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, 2002

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)

Telephone Number: (713) 420-2600
Internet Website: www.elpaso.com

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 Pacific 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. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☑ No ☐.

State the aggregate market value of the voting and non-voting common equity 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 June 28, 2002, computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $12,055,450,292.

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 27, 2003: 599,435,088

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 2003 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
Bbl = barrels
BBtu = billion British thermal units
BBtue = billion British thermal unit equivalents
Bcf = billion cubic feet
Bcfe = billion cubic feet of gas equivalents
MBbls = thousand barrels
Mcf = thousand cubic feet
Mcfe = thousand cubic feet of gas equivalents
Mgal = thousand gallons
MMBbls = million barrels
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of gas equivalents
MMDth = million dekatherm
MTons = thousand tons
MW = megawatt
MWh = megawatt hours
MMWh = thousand megawatt hours
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 a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "El Paso", we are describing El Paso Corporation and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are an 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. Since 1996, we have grown into an international energy company whose operations extend from natural gas production and extraction to power generation. Our growth during this period has been accomplished through several significant acquisitions and internal growth initiatives, each of which has expanded our competitive abilities in energy markets in the United States and abroad. Some of the significant highlights during this period were:

Year	Transaction	Impact
1996	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 capabilities. Established us as the general partner for El Paso Energy Partners, L.P.
1999	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.
2001	Merger with The Coastal Corporation	Placed us as a top tier participant in every aspect of the wholesale energy marketplace.

Since the fourth quarter of 2001, our industry and business have been adversely impacted by a number of industry changing events, including:

- The bankruptcy of Enron Corp.;
- The decline in the energy trading industry;
- Credit ratings downgrades of us and other industry participants by Moody's and Standard & Poor's to "below investment grade" status, and we remain on negative outlook; and
- Regulatory and political pressure arising out of the western energy crisis of 2000 and 2001.

Beginning in December 2001 and continuing throughout 2002 and the first quarter of 2003, we responded to these industry developments by focusing on activities that would enhance our liquidity and strengthen our capital structure. These activities involved:

- selling marginally performing assets and businesses that were not core to our fundamental base business of natural gas and pipelines;
- exiting complex areas that require higher credit support, such as energy trading, and focusing instead on core cash generating businesses; and
- pursuing resolution of regulatory and litigation matters, which led to a March 2003 agreement in principle to settle our primary exposure to the western energy crisis (Western Energy Settlement).

In February 2003 we announced what we refer to as our 2003 Operational and Financial Plan. This plan is based upon five key principles:

- Preserving and enhancing the value of our core businesses;
- Exiting non-core businesses quickly, but prudently;
- Strengthening and simplifying our balance sheet while maximizing liquidity;

- Aggressively pursuing additional cost reductions; and
- Continuing to work diligently to resolve litigation and regulatory matters.

Our ongoing critical areas of focus are:

- *Pipelines:* Protecting and enhancing asset value in our natural gas transportation business through continuous efficiency gains and prudent and necessary capital spending.
- *Production:* Developing production opportunities in North America that maximize volumes produced and minimize costs, thereby optimizing cash flow per unit produced.
- *Field Services:* Optimizing stable cash flows from our investment in El Paso Energy Partners, L.P.
- *Global Power:* Enhancing cash flows from existing projects, while selling non-strategic power generation facilities.

We will also continue to focus on winding down our non-core businesses including energy trading and petroleum markets as well as other capital intensive businesses such as liquefied natural gas (LNG) operations.

Segments

Our operations are segregated into four primary business segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. We manage each segment separately, and each segment requires different technology and marketing strategies. As future developments in our businesses occur, and as we carry out our ongoing strategy and plans, we will continue to assess the appropriateness of our business segments. For the operating results and identifiable assets by segment, you should see Part II, Item 8, Financial Statements and Supplementary Data, Note 24, which is incorporated herein by reference.

Our Pipelines segment owns or has interests in approximately 60,000 miles of interstate natural gas pipelines in the U.S. and internationally. In the U.S., our systems connect the nation's principal natural gas supply regions to the five largest consuming regions in the U.S.: the Gulf Coast, California, the Northeast, the Midwest and the Southeast. These pipelines represent one of the largest integrated coast-to-coast mainline natural gas transmission systems in the U.S. Our U.S. pipeline systems also own or have interests in approximately 440 Bcf of storage capacity used to provide a variety of services to our customers and own and operate an LNG terminal at Elba Island, Georgia. Our international pipeline operations include access between our U.S. based systems and Canada and Mexico as well as interests in three operating natural gas transmission systems in Australia.

Our Production segment conducts our natural gas and oil exploration and production activities. Domestically, we lease approximately 4 million net acres in 16 states, including Louisiana, Oklahoma, Texas and Utah, and in the Gulf of Mexico. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey. During 2002, daily equivalent natural gas production exceeded 1.6 Bcfe/d, and our reserves at December 31, 2002, were approximately 5.2 Tcfe.

Our Field Services segment conducts our midstream activities. As part of our plan to strengthen our capital structure and enhance our liquidity, we completed a number of asset sales during 2002, including the sale of our San Juan Basin gathering, treating and processing assets and our Texas and New Mexico midstream assets, including the intrastate natural gas pipeline system we acquired from Pacific Gas & Electric in 2000, to El Paso Energy Partners. El Paso Energy Partners is a publicly traded master limited partnership for which our subsidiary serves as general partner. As a result of asset sales to the partnership and others during 2002, our remaining Field Services assets consist of 23 processing plants and related gathering facilities located in the south Texas, Louisiana, Mid-Continent and Rocky Mountain regions, as well as our interests in El Paso Energy Partners. The partnership provides natural gas, natural gas liquids (NGL) and oil gathering, transportation, processing, fractionation, storage and other related services.

Our Merchant Energy segment consists of three primary divisions: global power, petroleum and energy trading. We are a significant owner of electric generating capacity and own or have interests in 88 power plants in 18 countries. We operate three refineries that have the capacity to process approximately 438 MBbls of crude oil per day and produce a variety of petroleum products. We also produce agricultural and industrial chemicals at four facilities in the U.S. and one in Canada. On February 5, 2003, we announced our intent to sell our remaining petroleum and chemicals assets, except for our Aruba refinery, as well as reduce our involvement in the LNG business. On November 8, 2002, we announced our plan to exit the energy trading business and pursue an orderly liquidation of our trading portfolio as a result of diminishing business opportunities and higher capital costs for this activity. During 2002 and the first part of 2003, we also completed or announced several asset sales including the sale of our coal mining assets and operations, petroleum assets and interests in power projects.

Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage, gathering and related services in the U.S. and internationally. We conduct our activities primarily through seven wholly owned and seven partially owned interstate transmission systems along with six underground natural gas storage entities and an LNG terminalling facility. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

		As of December 31, 2002			Average Throughput(1)		
Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity	Storage Capacity	2002	2001	2000
			(MMcf/d)	(Bcf)		(BBtu/d)	
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.	14,200	6,487	97	4,596	4,405	4,354
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,600	6,450	207	3,691	3,776	3,807
El Paso Natural Gas (EPNG)	Extends from the San Juan, Permian and Anadarko Basins to California, which is EPNG's single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	10,600	5,330(2)	—	3,799	4,253	3,937
Southern Natural Gas (SNG)	Extends from Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham.	8,000	2,963	60	2,020	1,877	2,132

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity is comprised of 4,530 MMcf/d of west-flow capacity (which includes 230 MMcf/d added by our Line 2000 expansion project) and 800 MMcf/d of east-end delivery capacity.

Transmission System	Supply and Market Region	As of December 31, 2002			Average Throughput[(1)]		
		Miles of Pipeline	Design Capacity	Storage Capacity	2002	2001	2000
			(MMcf/d)	(Bcf)		(BBtu/d)	
Colorado Interstate Gas (CIG)	Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest.	4,000	3,100	29	1,563	1,448	1,383
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,860	—	1,194	1,017	832
Mojave Pipeline (MPC)	Connects with the EPNG and Transwestern transmission systems at Topock, Arizona, and the Kern River Gas Transmission Company transmission system in California, and extends to customers in the vicinity of Bakersfield, California.	400	400	—	266	283	407

(1) Includes throughput transported on behalf of affiliates.

Partially Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2002			Average Throughput[(1)]		
		Ownership Interest	Miles of Pipeline	Design Capacity[(1)]	2002	2001	2000
		(Percent)		(MMcf/d)		(BBtu/d)	
Florida Gas Transmission	Extends from south Texas to Florida.	50	4,804	1,950	2,004	1,616	1,524
Alliance Pipeline[(2)]	Extends from western Canada to Chicago.	2	2,345	1,537	1,476	1,479	105
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,378	2,224	2,477
Dampier-to-Bunbury pipeline system	Extends from Dampier to Bunbury in western Australia.	33	1,152	570	573	555	523
Moomba-to-Adelaide pipeline system	Extends from Moomba to Adelaide in southern Australia.	33	685	383	271	261	231
Ballera-to-Wallumbilla pipeline system	Extends from Ballera to Wallumbilla in southwestern Queensland, Australia.	33	470	115	72	71	71
Portland Natural Gas Transmission	Extends from the Canadian border near Pittsburg, New Hampshire to Dracut, Massachusetts.	30[(3)]	294	214	144	123	110

(1) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.

(2) The Alliance pipeline project commenced operations in the fourth quarter of 2000. We sold 12.3 percent of our equity interest in the system during the fourth quarter of 2002, and the remaining 2.1 percent equity interest in the first quarter of 2003.

(3) Our ownership interest increased from 19 percent to 30 percent effective June 2001.

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage entities:

Underground Natural Gas Storage Entities

Storage Entity	As of December 31, 2002 Ownership Interest (Percent)	Storage Capacity[1] (Bcf)	Location
Bear Creek Storage	100	58	Louisiana
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage	50	13	Michigan
Steuben Gas Storage	50	6	New York
Young Gas Storage	48	6	Colorado

(1) Includes a total of 139 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

In addition to our operations of natural gas pipeline systems and storage facilities, we own an LNG receiving terminal located on Elba Island, near Savannah, Georgia. The facility is capable of achieving a peak send-out of 675 MMcf/d and a base load send-out of 446 MMcf/d. The terminal was placed in service and began receiving deliveries in December 2001. The capacity at the terminal is currently contracted to our affiliate, El Paso Merchant Energy, under a contract that extends through 2023. In September 2001, we announced plans to expand the peak send out capacity of the Elba Island facility by 540 MMcf/d and the base load send out by 360 MMcf/d (for a total peak send out capacity once completed of 1,215 MMcf/d and a base load send out of 806 MMcf/d). The expansion will cost approximately $145 million and has a planned in-service date of late 2005.

We have a number of transmission system expansion projects that have been approved by the Federal Energy Regulatory Commission (FERC) as follows:

Transmission System	Project	Capacity (MMcf/d)	Description[1]	Anticipated Completion Date
TGP	CanEast	127	Extend TGP's mainline system through a combination of lease capacity and facilities modifications, to the Leidy Hub.	April 2003
TGP	South Texas Expansion	312	Construct pipeline, compression and border crossing facilities to fuel four electric power generation plants in the Northern Mexico Municipalities of Rio Bravo and Valle Hermoso, State of Tamaulipas.	September 2003
ANR	Westleg Wisconsin Expansion	218	To increase capacity of ANR's existing system by looping the Madison lateral and by enlarging the Beloit lateral through abandonment and replacement.	November 2004
SNG	South System I (Phase 2)	196	Installation of compression and pipeline looping to increase firm transportation capacity along SNG's south mainline in Alabama, Georgia and South Carolina.	June 2003
SNG	South System II	330	Installation of compression and pipeline looping to increase firm transportation capacity along SNG's south mainline to Alabama, Georgia and South Carolina.	June 2003, November 2003 and May 2004
SNG	North System II	33	Installation of compression and additional pipeline looping to increase capacity along SNG's north mainline in Alabama.	June 2003
CIG	Valley Line	92	Installation of additional natural gas compression and air blending facilities to expand the deliverability of the Front Range system.	December 2003

(1) Pipeline looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases the transmission system's capacity.

Our transportation, storage and related services (transportation services) revenues consist of reservation and usage revenues. In 2002, approximately 87 percent of our transportation services revenues were attributable to a capacity reservation or a demand charge paid by firm customers. These firm customers are obligated to pay a monthly demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. The remaining 13 percent of our transportation services revenue was attributable to usage charges, based largely on the volumes of gas actually transported or stored on our pipeline systems.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each of our pipeline systems and storage facilities operates under FERC-approved tariffs that establish rates, terms and conditions for services to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage, terminalling and related services;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and marketing affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital. Consequently, our financial results have historically been relatively stable. However, these results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the creditworthiness of our customers.

In Canada, our pipeline activities are regulated by the National Energy Board. Similar to the FERC, the National Energy Board governs tariffs and rates, and the construction and operation of natural gas pipelines in Canada. In Australia, various regional and national agencies regulate the tariffs, rates and operating activities of natural gas pipelines.

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations. Our systems have ongoing programs designed to keep our facilities in compliance with pipeline safety and environmental requirements. We believe that our systems are in material compliance with the applicable requirements.

A discussion of significant rate and regulatory matters is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 20, and is incorporated herein by reference.

Markets and Competition

The following table details our markets and competition on each of our wholly owned pipeline systems as of December 31, 2002:

Transmission System	Customer Information[1]	Contract Information	Competition
TGP	Approximately 434 firm and interruptible customers Major Customers: None of which individually represents more than 10 percent of revenues	Approximately 436 firm contracts Contracted capacity: 93% Weighted average remaining contract term of approximately five years	TGP faces strong competition in the Northeast, Appalachian, Midwest and Southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at multiple connection points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. It also competes with pipelines and local distribution companies to deliver increased quantities of natural gas to our market areas. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and at the Canadian border.
ANR	Approximately 238 firm and interruptible customers Major Customer: We Energies (1,138 BBtu/d)	Approximately 643 firm contracts Contracted capacity: 98% Weighted average remaining contract term of approximately four years Contract terms expire in 2003-2010.	In the Midwest markets, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast markets, ANR competes with other interstate pipelines serving electric generation and local distribution companies. Also, Wisconsin Gas, which operates under the name We Energies, is a sponsor of Guardian Pipeline, which was placed in service in December 2002. Guardian will serve a portion of We Energies transportation requirements and will compete directly with ANR.
EPNG	Approximately 230 firm and interruptible customers Major Customer: Southern California Gas Company (1,235 BBtu/d) (95 BBtu/d)	Approximately 180 firm contracts Contracted capacity:[2] Weighted average remaining contract term of approximately five years Contract term expires in 2006. Contract terms expire in 2004-2007.	EPNG faces competition from other pipelines that deliver natural gas to California and the southwestern U.S., as well as alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
SNG	Approximately 260 firm and interruptible customers Major Customers: Atlanta Gas Light Company (959 BBtu/d) Alabama Gas Corporation (394 BBtu/d) Scana Resources Inc. (253 BBtu/d)	Approximately 170 firm contracts Contracted capacity: 100% Weighted average remaining contract term of approximately five years Contract terms expire in 2005-2007. Contract terms expire in 2005-2008. Contract terms expire in 2003-2017.	Competition is strong in a number of SNG's key markets. SNG's three largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of many of its other customers.

(1) Includes natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies.

(2) A discussion of significant rate and regulatory matters regarding EPNG's capacity is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 20.

Transmission System	Customer Information[1]	Contract Information	Competition
CIG	Approximately 125 firm and interruptible customers	Approximately 170 firm contracts Contracted capacity: 100% Weighted average remaining contract term of approximately seven years	CIG serves two major markets, the "on-system" market, consisting of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming, and the "off-system" market, consisting of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. Competition for the on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for the off-system market consists of other interstate pipelines that are directly connected to CIG's supply sources and transport these volumes to markets in the West, Northwest, Southwest and Midwest.
	Major Customer: Public Service Company of Colorado		
	(1,095 BBtu/d)	Contract term expires in 2007.	
	(462 BBtu/d)	Contract terms expire 2008-2025.	
WIC	Approximately 43 firm and interruptible customers	Approximately 47 firm contracts Contracted capacity: 100% Weighted average remaining contract term of approximately six years	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply. The Overthrust supply basin, which historically supplies the WIC mainline, has been declining and there has been increased competition from the pipelines serving the West and Northwest market areas for this gas supply. To replace these volumes, WIC is pursuing access to new supply sources. Additionally, WIC's one Bcf expandable Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply. Currently there are two other interstate pipelines that transport limited volumes out of this basin. Upon the approval and construction of the new Cheyenne Plain project[2], WIC will have an increased outlet to mid-continent markets.
	Major Customers: Williams Energy Marketing and Trading		
	(340 BBtu/d)	Contract terms expire in 2003-2013.	
	Western Gas Resources		
	(272 BBtu/d)	Contract terms expire in 2003-2013.	
	Colorado Interstate Gas Company		
	(247 BBtu/d)	Contract terms expire in 2003-2007.	
	CMS Field Services		
	(234 BBtu/d)	Contract terms expire in 2004-2013.	
MPC	Approximately 35 firm and interruptible customers	Eight firm contracts Contracted capacity: 98% Weighted average remaining contract term of approximately four years	MPC faces competition from other pipelines that deliver natural gas to California and the southwestern U.S. as well as alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
	Major Customers: Texaco Natural Gas Inc.		
	(185 BBtu/d)	Contract term expires in 2007.	
	Burlington Resources Trading Inc.		
	(76 BBtu/d)	Contract term expires in 2007.	
	Los Angeles Department of Water and Power		
	(50 BBtu/d)	Contract term expires in 2007.	

(1) Includes natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies.

(2) The Cheyenne Plain project is a new 30-inch diameter pipeline proposed by us to transport natural gas from the Cheyenne hub to the confluence of several pipelines near Greensburg, Kansas. This pipeline is anticipated to be in service in mid-2005 depending on the timing of regulatory approval.

Electric power generation is one of the fastest growing demand sectors of the natural gas market. The potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency and more effective use of surplus electric capacity as a result of open market access. In addition, in several regions of the country, new capacity additions have exceeded load growth and transmission capabilities out of those regions. This will result in lower growth in the gas demand in those regions associated with new power generation facilities.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing the delivery capabilities and operational flexibility and complementing traditional supply and market areas. These LNG delivery systems also may compete with pipelines for transportation of gas into market areas.

As our pipeline contracts expire, our ability to extend our existing contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

As a result of the rating agencies downgrading the credit rating of several members of the energy sector, including energy trading companies, and placing them on negative credit watch, the creditworthiness of some customers has deteriorated. We have taken actions to mitigate our exposure by requesting these companies provide us with letters of credit or prepayments as permitted by our tariffs. Our tariffs permit us to request additional credit assurance from our shippers equal to the cost of performing transportation services for various periods as specified in each tariff. If these companies experience financial difficulties, or file for Chapter 11 bankruptcy protection, and our contracts are not assumed by other counterparties, or if the capacity is unavailable for resale, it could have a material adverse effect on our financial position, operating results or cash flows.

Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., we have onshore and coal seam operations and properties in 16 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

Strategically, Production emphasizes disciplined investment criteria and manages its existing production portfolio to maximize volumes and minimize costs. It employs geophysical technology and seismic data processing to identify economic hydrocarbon reserves. Production's deep drilling capabilities and hydraulic fracturing technology allow it to optimize production with high-rate completions at competitive reserve replacement costs. Production maintains an active drilling program that capitalizes on its land and seismic holdings. It also acquires production properties subject to acceptable investment return criteria.

Natural Gas and Oil Reserves

The table below details Production's proved reserves at December 31, 2002. Information in this table is based on the reserve report dated January 1, 2003, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 465,783

MMcfe of production delivery commitments under financing arrangements that extend through 2042. The financing arrangement supported by these reserves matures in 2006. Total proved reserves on the fields with this dedicated production were 919,265 MMcfe. In addition, the table excludes the following equity interests: Production's interest in UnoPaso (Pescada in Brazil); Merchant Energy's interests in Sengkang in Indonesia, CAPSA and CAPEX in Argentina and Aguaytia in Peru; and Field Services' interest in El Paso Energy Partners. Combined proved natural gas reserves balances for these equity interests were 435,713 MMcf, liquids reserves were 39,693 MBbls and natural gas equivalents were 673,871 MMcfe, all net to our ownership interests.

	Net Proved Reserves[(1)]		
	Natural Gas (MMcf)	**Liquids[(2)] (MBbls)**	**Total (MMcfe)**
United States			
Producing	2,235,877	50,712	2,540,145
Non-Producing	448,303	20,094	568,868
Undeveloped	1,528,726	45,923	1,804,267
Total proved	4,212,906	116,729	4,913,280
Canada			
Producing	89,144	4,213	114,422
Non-Producing	14,555	233	15,953
Undeveloped	26,701	1,694	36,865
Total proved	130,400	6,140	167,240
Other Countries[(3)]			
Producing	—	—	—
Non-Producing	—	—	—
Undeveloped	76,032	12,652	151,944
Total proved	76,032	12,652	151,944
Worldwide			
Producing	2,325,021	54,925	2,654,567
Non-Producing	462,858	20,327	584,821
Undeveloped	1,631,459	60,269	1,993,076
Total proved	4,419,338	135,521	5,232,464

(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.
(3) Includes international operations in Brazil, Hungary and Indonesia.

During 2002, as a result of our efforts to enhance our liquidity position, we sold reserves totaling 1.8 Tcfe to various third parties. The reserves sold were primarily located in Colorado, Texas, Utah and western Canada.

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 Production's 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 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. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that 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 on the accuracy of the assumptions on 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 Part II, Item 8, Financial Statements and Supplementary Data, Note 28.

Wells and Acreage

The following table details Production's gross and net interest in developed and undeveloped onshore, offshore, coal seam and international acreage at December 31, 2002. Any acreage in which Production's interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
United States						
Onshore	1,142,805	445,427	1,278,683	928,135	2,421,488	1,373,562
Offshore	626,705	407,121	1,026,358	952,736	1,653,063	1,359,857
Coal Seam	217,412	119,674	1,204,020	781,462	1,421,432	901,136
Total	1,986,922	972,222	3,509,061	2,662,333	5,495,983	3,634,555
International						
Australia	—	—	1,770,364	677,350	1,770,364	677,350
Bolivia	—	—	154,840	19,355	154,840	19,355
Brazil	—	—	6,757,164	4,690,446	6,757,164	4,690,446
Canada	338,971	174,533	881,353	698,905	1,220,324	873,438
Hungary	—	—	568,100	568,100	568,100	568,100
Indonesia	—	—	1,213,170	378,397	1,213,170	378,397
Turkey	—	—	4,047,508	2,023,754	4,047,508	2,023,754
Total	338,971	174,533	15,392,499	9,056,307	15,731,470	9,230,840
Worldwide Total	2,325,893	1,146,755	18,901,560	11,718,640	21,227,453	12,865,395

(1) Gross interest reflects the total acreage we participated in, regardless of our ownership interests in the acreage.
(2) Net interest is the aggregate of the fractional working interest that we have in our gross acreage.

The U.S. domestic net developed acreage is concentrated primarily in the Gulf of Mexico (42 percent), Oklahoma (15 percent), Utah (14 percent), Texas (12 percent), and Louisiana (10 percent). Approximately 20 percent, 21 percent and 12 percent of our total U.S. net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2003, 2004 and 2005. During 2002, we sold approximately 421,316 net developed and 887,391 net undeveloped acres primarily in Colorado, Texas, Utah and western Canada as a result of our efforts to enhance our liquidity position.

The following table details Production's working interests in onshore, offshore, coal seam and international natural gas and oil wells at December 31, 2002:

	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
United States								
Onshore	1,937	1,502	335	257	2,272	1,759	47	36
Offshore	386	167	93	36	479	203	11	9
Coal Seam	1,756	1,001	—	—	1,756	1,001	6	4
Total	4,079	2,670	428	293	4,507	2,963	64	49
International								
Canada	267	170	135	77	402	247	6	5
Other	1	1	—	—	1	1	—	—
Total	268	171	135	77	403	248	6	5
Worldwide Total	4,347	2,841	563	370	4,910	3,211	70	54

(1) Gross interest reflects the total number of wells we participated in, regardless of our ownership interests in the wells.
(2) Net interest is the aggregate of the fractional working interest that we have in our gross wells.

During 2002, as a result of our efforts to enhance our liquidity position, we sold approximately 2,055 net wells located primarily in Colorado, Texas, Utah and western Canada.

The following table details Production's exploratory and development wells drilled during the years 2000 through 2002:

	Net Exploratory Wells Drilled			Net Development Wells Drilled		
	2002	2001	2000	2002	2001	2000
United States						
Productive	15	17	16	523	449	424
Dry	10	8	17	9	23	18
Total	25	25	33	532	472	442
Canada						
Productive	18	21	3	5	38	10
Dry	27	35	3	1	3	1
Total	45	56	6	6	41	11
Other Countries[1]						
Productive	1	—	—	—	—	—
Dry	1	9	1	—	1	—
Total	2	9	1	—	1	—
Worldwide						
Productive	34	38	19	528	487	434
Dry	38	52	21	10	27	19
Total	72	90	40	538	514	453

(1) Includes international operations in Australia, Brazil, Hungary, Turkey and Indonesia.

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, Sales Prices, Transportation and Production Costs

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

	2002	2001	2000
Net Production Volumes			
United States			
Natural Gas (Bcf)	470	552	516
Oil, Condensate and Liquids (MMBbls)	17	13	12
Total (Bcfe)	569	634	586
Canada			
Natural Gas (Bcf)	17	13	1
Oil, Condensate and Liquids (MMBbls)	1	1	—
Total (Bcfe)	23	17	1
Worldwide			
Natural Gas (Bcf)	487	565	517
Oil, Condensate and Liquids (MMBbls)	18	14	12
Total (Bcfe)	592	651	587
Natural Gas Average Sales Price (per Mcf)[(1)]			
United States			
Price excluding hedges	$ 3.19	$ 4.26	$ 3.97
Price including hedges	$ 3.64	$ 3.57	$ 2.73
Canada			
Price excluding hedges	$ 2.85	$ 2.86	$ 4.27
Price including hedges	$ 2.84	$ 2.85	$ 4.27
Worldwide			
Price excluding hedges	$ 3.16	$ 4.23	$ 3.97
Price including hedges	$ 3.61	$ 3.56	$ 2.73
Oil, Condensate, and Liquids Average Sales Price (per Bbl)[(1)]			
United States			
Price excluding hedges	$21.38	$23.08	$28.39
Price including hedges	$21.28	$22.39	$21.97
Canada			
Price excluding hedges	$21.56	$17.68	$ —
Price including hedges	$21.55	$18.52	$ —
Worldwide			
Price excluding hedges	$21.39	$22.87	$28.39
Price including hedges	$21.30	$22.24	$21.97

(1) Prices are stated before transportation costs.

	2002	2001	2000
Average Transportation Cost (per Mcfe)			
United States			
Natural gas	$ 0.18	$ 0.11	$ 0.11
Oil, condensate and liquids	$ 0.97	$ 0.57	$ 0.15
Canada			
Natural gas	$ 0.19	$ 0.17	$ 0.17
Oil, condensate and liquids	$ 0.39	$ 0.26	$ —
Worldwide			
Natural gas	$ 0.18	$ 0.12	$ 0.11
Oil, condensate and liquids	$ 0.93	$ 0.56	$ 0.15
Average Production Cost and Production Taxes (per Mcfe)[1]			
United States			
Average Production Cost	$ 0.50	$ 0.51	$ 0.41
Average Production Taxes	$ 0.08	$ 0.14	$ 0.12
Canada			
Average Production Cost	$ 0.80	$ 0.74	$ 0.66
Worldwide			
Average Production Cost	$ 0.51	$ 0.52	$ 0.41
Average Production Taxes	$ 0.08	$ 0.14	$ 0.12

[1] Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field 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 for each of the three years ended December 31:

	2002	2001 (In millions)	2000
United States			
Acquisition Costs:			
Proved	$ 362	$ 91	$ 201
Unproved	29	44	171
Development Costs	1,520	1,529	1,229
Exploration Costs:			
Delay Rentals	7	14	12
Seismic Acquisition and Reprocessing	35	37	64
Drilling	204	126	214
Total	$2,157	$1,841	$1,891
Canada			
Acquisition Costs:			
Proved	$ 6	$ 232	$ 3
Unproved	7	16	6
Development Costs	80	105	69
Exploration Costs:			
Seismic Acquisition and Reprocessing	21	10	10
Drilling	49	9	32
Total	$ 163	$ 372	$ 120

	2002	2001	2000
		(In millions)	
Other Countries[1]			
Acquisition Costs:			
Proved	$ —	$ —	$ —
Unproved	10	26	—
Development Costs	3	14	—
Exploration Costs:			
Seismic Acquisition and Reprocessing	34	6	18
Drilling	24	97	17
Total	$ 71	$ 143	$ 35
Worldwide			
Acquisition Costs:			
Proved	$ 368	$ 323	$ 204
Unproved	46	86	177
Development Costs	1,603	1,648	1,298
Exploration Costs:			
Delay Rentals	7	14	12
Seismic Acquisition and Reprocessing	90	53	92
Drilling	277	232	263
Total	$2,391	$2,356	$2,046

[1] Includes international operations in Australia, Brazil, Hungary, Indonesia and Turkey.

The table below details approximate amounts spent to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year:

Cost to Develop Proved Undeveloped Reserves	2002	2001	2000
		(In millions)	
United States	$482	$559	$286
Canada	11	17	24
Total	$493	$576	$310

Regulatory and Operating Environment

Production's natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world in which Production does business. These regulations include, but are not limited to, the 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 domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts 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. Production's international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international 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 believe that our operations are in material compliance with the applicable requirements. In addition, we maintain 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, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage on behalf of Production with respect to potential losses resulting from these operating hazards.

Markets and Competition

Our Production segment primarily sells its natural gas to third parties through our Merchant Energy segment at spot market prices. As a result of our plan to exit the energy trading business announced in November 2002, our Production segment is currently evaluating how it will sell its production in the future. Alternatives being considered include whether to cancel its agreement with Merchant Energy and assume responsibility for natural gas sales to third parties or enter into new marketing agreements with third parties engaged in the marketing of natural gas. Production 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 also engages in hedging activities on its natural gas and oil production to stabilize its cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved primarily through natural gas and oil swaps. Under our hedging program, we may hedge up to 50 percent of our anticipated production for a rolling 12-month forward period.

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 natural gas liquids. Production's competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and quality of service. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Field Services Segment

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and NGL. It also provides well-ties and real-time information services, including electronic wellhead gas flow measurement.

Field Services' assets include natural gas gathering and NGL pipelines, treating, processing and fractionation facilities, in the south Texas, Louisiana, Mid-Continent and Rocky Mountain regions.

El Paso Energy Partners Company, a subsidiary in our Field Services segment serves as the sole general partner of El Paso Energy Partners. We currently own 26.5 percent, or 11,674,245 of the partnership's common units and the one percent general partner interest. The remaining 73.5 percent of the common units of the limited partnership are owned by public unit holders (including small amounts owned by the general partner's management and employees), none of which exceeds a 10 percent ownership interest. Field Services also owns all 125,392 of the outstanding Series B preference units and all 10,937,500 of the outstanding Series C units issued in November 2002, which are non-voting. Our overall voting interest in El Paso Energy Partners is 26.5 percent.

As the general partner, Field Services manages the partnership's daily operations. Employees of Field Services perform all of the limited partnership's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. El Paso Energy Partners contributes to our income through our general partner interest and our ownership of common and preference units. We do not have any loans to or from El Paso Energy Partners. In addition, we have not provided any guarantees, either monetary or performance, on behalf of or for the benefit of El Paso Energy Partners nor do we have any other liabilities other than those arising in the normal course of business or those arising out of our role as the general partner in El Paso Energy Partners.

El Paso Energy Partners provides a capital-efficient means of expanding our midstream business, and through our general partner relationship, we have used the partnership as our primary means of growth of our midstream natural gas business. El Paso Energy Partners manages a balanced, diversified portfolio of interests and assets related to the midstream energy sector, which includes:

- offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas;
- onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas;
- onshore NGL pipelines and fractionation facilities in Texas; and
- onshore natural gas and NGL storage facilities in Mississippi, Louisiana and Texas.

We enter into transactions with El Paso Energy Partners in the normal course of business for the purchase of natural gas and for services such as transportation and fractionation, storage, processing and other types of operational services. For a further discussion of these activities and the impact of El Paso Energy Partners on our Field Services operations, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following tables provide information on Field Services' natural gas gathering and transportation facilities, its processing facilities and the facilities of its equity method investees:

	As of December 31, 2002		Average Throughput		
Gathering & Treating	**Miles of Pipeline**	**Throughput Capacity**	**2002**	**2001**	**2000**
		(MMcfe/d)		**(BBtue/d)**	
El Paso Field Services	4,048	1,563	3,023[1]	6,109[2]	3,868
El Paso Energy Partners[3]	15,764	10,345	6,686[1]	1,946	1,714

	As of December 31, 2002	Average Inlet Volume			Average Natural Gas Liquids Sales		
Processing Plants	**Inlet Capacity**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
	(MMcfe/d)		**(BBtue/d)**			**(Mgal/d)**	
El Paso Field Services	4,911	3,920	4,360	2,930	6,635[1]	7,122[2]	4,664
El Paso Energy Partners[3]	950	729	—	—	266	—	—

(1) During 2002, we sold a number of assets to El Paso Energy Partners including gathering and processing assets in the San Juan Basin of New Mexico and our Texas midstream assets, most of which we acquired in December 2000.

(2) The increase in activity from 2000 to 2001 is a result of our acquisition of PG&E's Texas Midstream operations in December 2000.

(3) All volumetric information for El Paso Energy Partners reflects 100 percent of El Paso Energy Partners' interest. Mileage and volumetric information have not been reduced to reflect our net ownership.

Regulatory Environment

Some of Field Services' operations are subject to regulation by the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each entity subject to the FERC's regulation operates under separate FERC approved tariffs with established rates, terms and conditions of service.

Some of Field Services' operations are also subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of Field Services' operations, owned directly or through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and various environmental statutes and regulations. Each of the pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and Field Services believes that these systems are in material compliance with the applicable requirements.

Markets and Competition

Field Services competes with major interstate and intrastate pipeline companies in transporting natural gas and NGL. 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 NGL. 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.

Merchant Energy Segment

Our Merchant Energy segment consists of three primary divisions: global power, petroleum and energy trading.

Global Power

Our global power division includes the ownership and operation of domestic and international power generation facilities. Our commercial focus in the power generation business has been to either develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing attractive power purchase agreements. Under this strategy, we have become a significant U.S.-based independent power generator and currently own or have interests in 88 power plants in 18 countries. These plants represent 20,665 gross megawatts of generating capacity, 72 percent of which is sold under power purchase or tolling agreements with terms in excess of five years. Of these facilities, 60 percent are natural gas fired, 11 percent are geothermal and the remaining 29 percent use coal or NGL as fuel or are hydroelectric plants. As part of our 2003 Operational and Financial Plan, we have announced the planned sales of some of these power generation assets. Most of our power plants are partially owned by us through either a direct equity investment or through our unconsolidated affiliates, Chaparral Investors, L.L.C. (Chaparral) and Gemstone. As of December 31, 2002, we had a direct investment in the following power plants:

Project	Gross Megawatts[1]	El Paso Ownership Interest
		(Percent)
Aguaytia Energy	155	24
Bastrop Company, LLC	534	50
Berkshire Power Company L.L.C.[2]	261	25
CAPSA/CAPEX	650	27
CDECCA[2]	62	50
CE Generation[3]	823	50
Costanera	2,302	12
Eagle Point Cogeneration Partnership[2]	233	84
East Asia Power	236	46
EGE Fortuna	300	25
EGE Itabo	513	25
Enfield Power	378	25
Fauji Kabirwala	157	42

(1) Gross megawatts represent tested generating capacity of these facilities.
(2) Chaparral also owns an interest in these projects.
(3) These projects were sold in 2003.

Project	Gross Megawatts[(1)]	El Paso Ownership Interest
		(Percent)
Habibullah Power	136	50
Kladno Power[(2)]	365	18
Korea Independent Energy Corporation	1,720	50
Manaus[(3)]	238	100
MASSPOWER[(4)]	270	18
Meizhou Wan Generating	734	25
Mid-Georgia Cogeneration	308	50
Midland Cogeneration Venture	1,575	44
Milford Power Company[(4)(5)]	540	25
Nejapa Power	144	87
PPN	325	26
Rio Negro[(3)]	158	100
Saba Power Company	128	93
Sengkang	135	48
Other projects	1,271	various
Total	14,651	

(1) Gross megawatts represent tested generating capacity of these facilities.
(2) These projects were sold in 2003.
(3) Gemstone also owns an interest in these projects.
(4) Chaparral also owns an interest in these projects.
(5) This plant is under construction.

We conduct a significant portion of our domestic power activity through our investment in Chaparral. At December 31, 2002, we owned 20 percent of Chaparral, and Limestone Electron Trust (Limestone), an unrelated party capitalized by private equity and debt, owned the remaining 80 percent. Limestone is controlled by investment affiliates of Credit Suisse First Boston Corporation. In March 2003, we notified Limestone that we will exercise our right under the partnership agreements to acquire all of the outstanding third party equity in Limestone. On March 17, 2003, we contributed $1 billion to Limestone in exchange for a non-controlling interest. Limestone used the proceeds from the contribution to pay off $1 billion of the Limestone notes that matured on that date. Following our additional investment of $1 billion in Limestone, our effective ownership of Chaparral increased to approximately 90 percent, but neither our rights nor the rights of Limestone to participate in the operating decisions of Chaparral changed. As a result, we continue to account for our investment in Chaparral as an equity investment. We will consolidate Chaparral upon the purchase of the remaining third party equity interest in Limestone, which we expect to occur in May 2003.

Chaparral was formed during 1999 to obtain low-cost financing to fund the growth of our unregulated domestic power generation and related businesses. During 2002, Chaparral's primary focus was on restructuring power contracts. A power contract restructuring is accomplished typically by amending an above-market power contract that requires delivery of power from a dedicated power plant and replacing it with low-cost power obtained from the market. Chaparral also operates power plants whose contracts have been previously restructured on a merchant basis, which means that these plants operate and sell power to the wholesale market in periods where power prices are high enough that it is economical to do so. Through Chaparral, we have investments in 34 U.S. power generation facilities with a total generating capacity of approximately 5,592 gross megawatts. Most of Chaparral's plants provide power under long-term contracts. We serve as the manager of Chaparral under a management agreement that expires in 2006, and we were paid a management fee for the services we performed under this agreement through the end of 2002. This fee was based on how well we performed as the manager of Chaparral, and was determined by evaluating the present value of the portfolio of power assets held by Chaparral. Our management fee is subject to the approval of our joint venture partner annually. In 2002, the management fee was $205 million consisting of a $185 million performance fee plus a $20 million annual cost reimbursement. We will not earn a fee from Chaparral in 2003.

As of December 31, 2002, Chaparral owned or had interests in the following power plants:

Project	Gross Megawatts[1]	Chaparral Ownership Interest
		(Percent)
Berkshire Power Company L.L.C.[2]	261	31
Cambria Cogen Company, G.P.	80	100
CDECCA[2]	62	50
Dartmouth Power Associates, L.P.	68	100
Eagle Point Cogeneration Partnership[2]	233	16
East Coast Power L.L.C.[3]	1,131	82
El Paso Golden Power, L.L.C.[3]	435	32
Front Range[4]	500	50
Juniper Generation, L.L.C.[3]	682	25
Linden 6 Expansion	169	99
MASSPOWER[2]	270	33
Milford Power Company[2][4]	540	70
Nevada Cogeneration Associates #1	85	50
Newark Bay Cogeneration Partnership L.P.	147	100
Orlando CoGen Limited, L.P.	115	50
Pawtucket Power Associates L.P.	69	100
Prime Energy Limited Partnership	52	50
San Joaquin CoGen L.L.C.	48	100
Vandolah	645	100
Total	5,592	

(1) Gross megawatts represent the tested generating capacity of these facilities.
(2) We also own a direct interest in these projects.
(3) These project companies own interests in multiple plants.
(4) These plants are under construction.

Internationally, our focus has been on building and acquiring energy infrastructure in developed economies, and to a lesser degree in selected emerging markets. Our primary areas of focus historically have included Brazil, Europe and Asia. We principally conduct our Brazilian development activities within an investment that we refer to as Gemstone. We own approximately 50 percent of Gemstone, and Gemstone Investors, an unrelated party capitalized by private equity (Rabobank International) and debt, owns the remaining 50 percent. Gemstone Investor Limited also indirectly purchased preferred interests in two of our consolidated power projects in Brazil. The Gemstone structure owns or has interests in five Brazilian power generation facilities with a total generating capacity of approximately 2,184 gross megawatts. We serve as the manager of Gemstone under a management agreement that expires in 2004, under which we are paid a fee that reimburses us for the cost to provide the management services, which cannot exceed $2 million on an annual basis. Our activities as manager of Gemstone include:

- management of the operations and commercial activities of the facilities;
- project financings, sales and acquisitions; and
- daily administration activities of accounting, tax, legal and treasury functions.

As of December 31, 2002, Gemstone owned or had interests in the following power plants:

Project	Gross Megawatts[(1)]	Gemstone Ownership Interest
Macae	895	100%
Porto Velho[(2)]	409	50%
Araucaria	484	60%
Rio Negro	158	[(3)]
Manaus	238	[(3)]
Total	2,184	

(1) Gross megawatts represent the tested generating capacity of these facilities.

(2) The second phase of this project is under construction.

(3) These are consolidated power projects in which Gemstone owns a preferred ownership interest.

Rabobank International, the third party investor in Gemstone, has the right to remove us as manager of Gemstone. In January 2003, Rabobank notified us that it planned to remove us as manager. We retained our management rights by agreeing to purchase Rabobank's $50 million of equity in Gemstone on or before April 17, 2003. We will consolidate Gemstone, its related power plants and its debt on the purchase date, unless we replace Rabobank with another partner.

For a further discussion of both Chaparral's and Gemstone's activities, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 26.

Detailed below are our power generation projects, by region (segregated by those that are consolidated and those that are not) as of December 31, 2002:

Consolidated Power Projects

Region	Project Status	Number of Facilities	Gross Megawatts[(1)]	Net Megawatts[(2)]
North America				
East Coast	Operational	4	429	429
South America	Operational	2	396	396
Asia	Operational	2	108	95
Central America	Operational	1	144	125
Europe	Operational	1	69	35
Total		10	1,146	1,080

(1) Gross megawatts represent the tested generating capacity of these facilities.

(2) Net megawatts represent our net ownership in the facilities.

Unconsolidated Power Projects

Region	Project Status	Number of Facilities	Gross Megawatts[(1)]	Net Megawatts[(2)]
North America				
East Coast	Operational	20	4,050	2,891
	Under Construction	1	540	513
Central	Operational	3	2,309	1,052
	Under Construction	1	500	250
West Coast	Operational	25	1,363	514
South America	Operational	6	4,698	1,780
	Under Construction	1	197	99
Asia	Operational	13	4,023	1,842
Central America	Operational	5	1,046	294
	Under Construction	1	50	11
Europe	Operational	2	743	159
Total		78	19,519	9,405

(1) Gross megawatts represent the tested generating capacity of these facilities.
(2) Net megawatts represent our net ownership in the facilities.

Petroleum

In February 2003, we announced our intent to sell substantially all of our petroleum business (with the exception of our Aruba refinery) since it is not core to our primary natural gas business. In addition, we also announced our intent to minimize our involvement in a developing LNG business because the significant capital and credit requirements associated with this business were in excess of our current financial capacity.

Our existing petroleum division: (i) owns or has interests in four crude oil refineries and five chemical production facilities; (ii) has petroleum terminalling and related marketing operations; and (iii) has blending and packaging operations that produce and distribute a variety of lubricants and automotive related products. Of the four refineries we own, we operate three of them. The three refineries we operate have a throughput capability of approximately 438 MBbls of crude oil per day to produce a variety of gasolines, diesel fuels, asphalt, industrial fuels and other products. Our chemical facilities have a production capability of 3,800 tons per day and produce various industrial and agricultural products.

In 2002, our refineries operated at 64 percent of their average combined capacity, at 70 percent in 2001 and at 93 percent in 2000. The aggregate sales volumes at our wholly owned refineries were approximately 110 MMBbls in 2002, 131 MMBbls in 2001 and 182 MMBbls in 2000. Of our total refinery sales in 2002, 38 percent was gasoline, 41 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 21 percent was heavy industrial fuels and other products.

The following table presents average daily throughput and storage capacity at our wholly owned refineries at December 31:

Refinery	Location	Average Daily Throughput 2002	2001	2000	At December 31, 2002 Daily Capacity	Storage Capacity
		(In MBbls)				
Aruba	Aruba	146	178	229	280	15,320
Eagle Point	Westville, New Jersey	127	118	143	140	8,492
Corpus Christi[(1)]	Corpus Christi, Texas	—	38	99	—	—
Mobile	Mobile, Alabama	9	10	12	18	600
Total		282	344	483	438	24,412

(1) In June 2001, we leased our Corpus Christi refinery to Valero Energy Corporation for 20 years. In February 2003, Valero exercised its option to purchase the plant and related assets. These volumes only reflect those produced prior to our lease of the facilities.

Our chemical plants produce agricultural fertilizers, gasoline additives and other industrial products from facilities in Nevada, Oregon and Wyoming. The following table presents sales volumes from our wholly owned chemical facilities in the U.S. for each of the three years ended December 31:

	2002	2001	2000
		(MTons)	
Industrial	512	492	547
Agricultural	380	378	389
Gasoline additives	199	173	214
Total	1,091	1,043	1,150

Since January 2003, we have sold the majority of our interests in our Florida petroleum terminals, our tug and barge operations, our leasehold crude business and asphalt operations and all of our interests in the Corpus Christi refinery. We expect to sell the rest of the assets associated with our petroleum business in 2003, with the exception of the Aruba refinery.

Our LNG business contracts for LNG terminalling and regasification capacity, coordinates short and long-term LNG supply deliveries and, prior to our announced intent to minimize our involvement in this business, was developing an international LNG supply, marketing and infrastructure business. As of December 31, 2002, our LNG business had contracted for 163 Bcf per year of LNG regasification capacity at the Elba Island location in Georgia, which is contracted through 2023.

We have contracted for 103 Bcf per year of LNG supplies at market sensitive prices, under the terms of a long-term Caribbean supply agreement. Initial deliveries under this agreement are scheduled to commence in June 2003. In May 2002, we received final approval from the Norwegian and United States governments for an LNG purchase and sale agreement signed in October 2001 with Snøhvit, which is a consortium of natural gas production companies led by Statoil ASA. In the fourth quarter of 2002, we completed a sale of our position in the LNG purchase and sale agreement and an assignment of our capacity rights at the Cove Point LNG regasification facility to Statoil for $210 million.

During 2001 and 2002, we contracted to charter four LNG tankers, with an option to charter a fifth ship, to transport LNG from supply areas to domestic and international market centers. In February 2003, following our announced plan to minimize our involvement in the LNG business, we entered into various agreements with the ship owners under which all four of the ship charters and our option for chartering the fifth ship were cancelled in consideration of payments by us totaling $24 million. On two of the ship charters, the ship owners assumed responsibility for the charter of those vessels, and we paid $20 million for the capital costs associated with fitting those two ships with regasification capabilities. In connection with transferring the chartering responsibilities back to the ship owners, we agreed to provide letters of credit, fully collateralized by cash, equal to $120 million that could be drawn on by the ship owners. These letters of credit are intended to cover additional capital costs and any shortfalls in the rates at which they are able to charter the vessels, compared to the rates provided for in the original charter agreements, as adjusted for capital costs we have already paid. In the event that the ship owners are able to charter the ships at rates in excess of the original rates, as adjusted, we will share in the benefits. We also retained rights to charter some of the vessels for our use in potential future LNG activities. In connection with these transactions, our future exposure to the ship arrangements is limited to $120 million. We also transferred our interest in our Baja LNG development project to an unaffiliated third party in connection with these transactions. We are exploring our options with respect to the remainder of our LNG business, including the sales of assets and supply and sales contracts, and participating in joint ventures that would use our Energy Bridge technology (technology which uses regasification capability on board the LNG transport ships in combination with or instead of using land-based facilities).

Energy Trading

At the beginning of 2002, we were one of the largest energy marketers in North America. Our trading activities included providing both short and long-term supplies of energy commodities to a broad range of wholesale customers worldwide. We traded natural gas, power, crude oil, other energy commodities and related financial instruments in North America and Europe and provided pricing and valuation analysis for the entire Merchant Energy segment. Detailed below is our marketed and traded energy commodity sales volumes that were settled during each of the three years ended December 31:

Volumes	2002	2001	2000
Physical			
Natural gas (BBtu/d)	11,879	9,230	7,768
Power (MMWh)	469,477	217,387	115,303
Financial settlements (BBtue/d)	188,467	143,095	98,630

Due to deterioration of the energy trading environment, we decided in November 2002 to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. We anticipate this liquidation will continue through 2004. Our liquidation strategy is intended to:

- maximize cash flow from the trading portfolio;
- reduce our risk in an uncertain environment; and
- avoid inefficient sales of the portfolio in the current distressed environment.

We will execute this strategy in several ways, including:

- negotiating early settlements pursuant to contractual terms with counterparties;
- actively pursuing the sales of transactions or the entire portfolio with third parties;
- matching and transferring offsetting positions with different counterparties;
- transferring activities to other El Paso segments or divisions; and
- liquidating through scheduled settlements.

In late 2002, we began actively liquidating our trading portfolio. As of December 31, 2002, we had approximately 40,000 transactions to be settled in the future. Included in our portfolio at that time was approximately 4.4 Bcf/d of natural gas transportation capacity and natural gas storage rights of approximately 125 Bcf. As of December 31, 2002, we had contracted to sell 2.1 Bcf/d of this transportation capacity and 70 Bcf of those gas storage rights. Additionally, in the first quarter of 2003, we sold our European natural gas trading portfolio and completed the liquidation of all of our open trading positions in Europe. We are continuing to work with numerous counterparties to liquidate the remainder of our portfolio through 2004.

Historically, our energy trading division purchased a significant portion of the Production segment's natural gas production and a smaller amount of the Field Services segment's natural gas and NGL volumes, as well as power generated from the global power division's merchant power plants. These purchases comprised approximately 20 percent and 1 percent of the energy trading division's 2002 natural gas and power volumes included in the above table. With our announcement that we will exit the trading business, these affiliated activities are being evaluated to determine if they should be assumed by the individual segment or whether each segment will separately contract for those services with third parties that are actively engaged in that business.

Regulatory Environment

Merchant Energy's domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to its rates, terms and conditions of service. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Merchant Energy's cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act (PURPA) with respect to rates, procurement and provision of services and operating standards. Its power generation and refining, chemical and petroleum activities are also subject to federal, state and local environmental regulations. We believe that our operations are in material compliance with the applicable requirements.

Merchant Energy's foreign operations are regulated by numerous governmental agencies in the countries in which these projects are located. 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 material compliance with all environmental laws and regulations in the applicable foreign jurisdictions.

Markets and Competition

During 2002, Merchant Energy's activities served over 2,200 suppliers and 3,800 customers around the world.

Merchant Energy's 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;
- independent energy marketers and power producers with varying scopes of operations and financial resources; and
- independent refining and chemical companies.

Merchant Energy competes on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served by Merchant Energy is influenced directly or indirectly by energy market economics.

Many of Merchant Energy's power generation facilities sell power pursuant to long-term agreements with investor-owned utilities in the U.S. The terms of its power purchase agreements for its facilities are such that Merchant Energy's revenues from these facilities are not significantly impacted by competition from other sources of generation. 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.

As a part of our strategy to exit the energy trading business, we will seek to sell a portion or all of our trading price risk management assets and liabilities to other energy marketers or financial institutions which engage in energy trading activities. With the deterioration of the profitability and credit standing of entities in the energy trading business, many industry participants have announced their decision to exit the energy trading business. We may face competition for limited resources in liquidating our trading price risk management assets and liabilities from these other energy trading companies, and this competition may impact the amounts we will be able to realize through our liquidation efforts.

Corporate and Other Operations

Through our corporate group, we perform management, legal, accounting, 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 telecommunications business and discontinued operations, including coal and retail, are also included in Corporate and Other Operations.

Telecommunications

Our on-going telecommunication business, which we conduct through our subsidiary, El Paso Global Networks, focuses on providing Texas-based metro transport services and collocation and cross-connect services in Chicago. Our Texas-based metro transport services business provides bandwidth transport services to wholesale and commercial customers in Austin, San Antonio, Dallas, Ft. Worth and Houston. Our collocation and cross-connect services are available through space we lease in Lakeside Technology Center, a Chicago-based telecommunications facility. This facility provides space for telecommunication carriers that is designed for their unique equipment needs and provides access to multiple network connections of various telecommunication carriers.

Regulatory Environment

The passage of the 1996 Telecommunications Act created a legal framework for competitive telecommunications companies to provide local, analog and digital communications services in competition with the traditional telephone companies. The 1996 Telecommunications Act eliminated a substantial barrier to entry for competitive telecommunications companies by enabling them to leverage the existing infrastructure built by the traditional telephone companies rather than constructing a competing infrastructure at significant and uneconomic cost.

A critical aspect of our Texas-based metro business is our interconnection agreement with SBC Communications Inc. (SBC). We have pending arbitration proceedings in Texas relating to the various terms of our new interconnection arrangements. Although we have received a favorable decision from an administrative law judge (ALJ) that supports the requirements needed in our current business plan, the Public Utility Commission of Texas (PUC) is reviewing the new language of the interconnection arrangement and is having ongoing proceedings to determine the rates, charges and terms, and conditions for collocation and unbundled network elements. Unbundled network elements are the various portions of a traditional telephone company's network that a competitive telecommunications company can lease for purposes of building a facilities-based competitive network, including end loops, central office collocation space, and interoffice transport. The interconnection agreement is ultimately subject to PUC, Federal Communications Commission (FCC) and judicial oversight. These government authorities may modify the terms of the interconnection agreements in a way that significantly disadvantages our business.

The FCC has commenced a rulemaking proceeding as part of its triennial review of its unbundling rules. In this proceeding, the FCC has undertaken a reexamination of its unbundling rules. These rules provide the legal means by which we obtain access to collocation, interoffice transport, and other unbundled network elements that are vital to our business plan and our ability to serve current and future customers. In particular, we rely on unbundled network elements, leased from SBC pursuant to FCC rules, in order to reach customers. Should the FCC decide to change its rules to limit our access to such elements, our ability to provide our Texas-based metro services could be significantly impacted. Additionally, legislative changes, either from Congress or the Texas legislature, may occur, which could also limit our access to unbundled network elements and significantly impact our business.

Markets and Competition

The markets for wholesale and commercial telecommunication services are intensely competitive, and we expect that these markets will continue to be competitive in the future. In the Texas markets, SBC offers similar services to ours and represents competition in all of our target service areas.

Not many competitive telecommunications companies offer services using a business strategy similar to ours. However, some competitive telecommunications companies have adopted the same or modified versions of our interconnection agreement, and other companies may continue to do so in the future. As a result, some of these competitors offer similar services and are likely to do so in the future.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 20, and is incorporated herein by reference.

Employees

As of March 26, 2003, we had approximately 11,855 full-time employees, of which 900 are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of March 28, 2003, 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
Ronald L. Kuehn, Jr.	Chairman and Chief Executive Officer of El Paso	2003	67
H. Brent Austin	President and Chief Operating Officer of El Paso	1992	48
D. Dwight Scott	Executive Vice President and Chief Financial Officer of El Paso	2002	39
John W. Somerhalder II	Executive Vice President of El Paso and President of El Paso's Pipeline Group	1990	47
Peggy A. Heeg	Executive Vice President and General Counsel of El Paso	1997	43
Robert W. Baker	Executive Vice President of El Paso and President of El Paso Global Power	1996	46
Greg G. Jenkins	Executive Vice President of El Paso	1996	45
David E. Zerhusen	Executive Vice President of El Paso	2000	47
Rodney D. Erskine	President of El Paso Production	2001	58
Robert G. Phillips	President of El Paso Field Services	1995	48
Clark C. Smith	President of El Paso's Trading Group	2000	48

Mr. Kuehn has been Chairman of the Board and Chief Executive Officer since March 2003. From September 2002 to March 2003, Mr. Kuehn was the Lead Director of El Paso. From January 2001 to March 2003, he was a business consultant. Mr. Kuehn served as non-executive Chairman of the Board of El Paso from October 1999 to December 2000. Mr. Kuehn served as President and Chief Executive Officer of Sonat Inc. from June 1984 until his retirement in October 1999. He was Chairman of the Board of Sonat Inc. from April 1986 until his retirement. He is a director of AmSouth Bancorporation, Praxair, Inc. and The Dun & Bradstreet Corporation.

Mr. Austin has been President and Chief Operating Officer of El Paso since October 2002. He was an Executive Vice President of El Paso from May 1995 to September 2002 and was Chief Financial Officer of El Paso from April 1992 to September 2002. Prior to that period, he served in various positions with Burlington Resources Inc. and Burlington Northern Inc.

Mr. Scott has been Executive Vice President and Chief Financial Officer of El Paso since October 2002. Mr. Scott served as Senior Vice President of Finance and Planning for El Paso from July 2002 to September 2002. He has held various other positions within El Paso since October 2000. Prior to that time, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

Mr. Somerhalder has been an Executive Vice President of El Paso since April 2000, and President of our Pipelines 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 Senior Vice President of El Paso from August 1992 to April 1996.

Ms. Heeg has been Executive Vice President and General Counsel of El Paso since January 2002. She was Senior Vice President and Deputy General Counsel from April 2001 to December 2001 and Vice President and Associate General Counsel for regulated pipelines from 1997 to 2001. Ms. Heeg has held various positions in the legal department of Tenneco Energy and El Paso since 1989.

Mr. Baker has been Executive Vice President of El Paso and President of El Paso Global Power since February 2003. He was Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time he held various positions in the legal department of Tenneco Energy and El Paso since 1983.

Mr. Jenkins has been Executive Vice President of El Paso since January 2002. He was President of El Paso Global Networks from August 2000 to January 2002. He was President of El Paso 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. Zerhusen has been Executive Vice President of El Paso since November 2002. He was Senior Vice President and Deputy General Counsel of El Paso from April 2001 to November 2002. Prior to joining El Paso, Mr. Zerhusen served as Vice President of Law for Tenneco Europe in London and held various positions with Tenneco in Houston. Prior to that time, he was a litigation partner with the law firm of Jenner and Block.

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. 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 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. Phillips is the Chairman of the Board of Directors of El Paso Energy Partners Company, the general partner of El Paso Energy Partners, L.P.

Mr. Smith has been President of El Paso's Trading Group since January 2003. He was President of El Paso Merchant Energy North America from August 2000 to January 2003. 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.

Executive officers hold offices until their successors are elected and qualified, subject to their earlier removal. Each of these elected officers also hold officer and/or director positions with our affiliated entities.

Available Information

Our website is http://www.elpaso.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the Securities and Exchange Commission (SEC). Information contained on our website is not part of this report.

ITEM 2. PROPERTIES

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

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 20, and 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 and the Pacific Exchange under the symbol EP. As of March 27, 2003, we had 52,489 stockholders of record, which does not include beneficial owners 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	Dividends
		(Per share)	
2002			
Fourth Quarter	$11.91	$ 4.39	$0.2175
Third Quarter	21.07	5.30	0.2175
Second Quarter	46.80	18.88	0.2175
First Quarter	46.89	31.70	0.2175
2001			
Fourth Quarter	$54.05	$36.00	$0.2125
Third Quarter	54.48	38.00	0.2125
Second Quarter	71.10	49.90	0.2125
First Quarter	75.30	57.25	0.2125

In February 2003, our Board of Directors declared a quarterly dividend of $0.04 per share of common stock, payable on April 7, 2003, to stockholders of record on March 7, 2003. Future dividends will be dependent upon business conditions, earnings, our cash requirements and other relevant factors.

We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. This 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. This 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 at 1-877-453-1503.

Equity Compensation Plan Information

The following table provides information concerning our equity compensation plans as of December 31, 2002. The table is divided into two categories: plans that have been approved by stockholders and equity compensation plans that have not been approved by stockholders. The table includes (a) the number of securities to be issued upon exercise of options, warrants and rights outstanding under the equity compensation plans, (b) the weighted-average exercise price of all outstanding options, warrants and rights and (c) additional shares available for future grants under all of our equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1]	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	7,820,635	$40.904	7,087,410[2]
Equity compensation plans not approved by stockholders	32,107,007	$52.562	19,775,268[3]
Total	39,927,642		26,862,678

(1) Amounts do not include 3,279,772 shares with a weighted-average exercise price of $35.788 per share which we assumed under the Executive Award Plan of Sonat Inc. as a result of the merger with Sonat in October 1999. The Executive Award Plan of Sonat Inc. has been terminated and no future awards can be made under it.

(2) Amount includes 2,831,050 shares available for future issuance under the Employee Stock Purchase Plan.

(3) Amount includes 69,250 shares available for future awards granted under the Restricted Stock Award Plan for Management Employees.

Non-Stockholder Approved Plans

The following is a discussion of the plans that have not been approved by our stockholders:

Strategic Stock Plan. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted common stock to non-employee members of our Board of Directors, officers and key employees primarily in connection with our strategic acquisitions. As the plan administrator, we determine which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of the grant. If a change in control, as it is defined in the plan, occurs: (1) all outstanding stock options become fully exercisable (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted common stock automatically lapse.

Restricted Stock Award Plan for Management Employees. The plan provides for the granting of restricted shares of our common stock to our management employees (other than executive officers and directors) for specific accomplishments beyond that which are normally expected and which will have a significant and measurable impact on our long-term profitability. As the plan administrator, we designate which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of the grant.

Omnibus Plan for Management Employees. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted common stock to our salaried employees (other than employees covered by a collective bargaining agreement). If a change in control, as it is defined in the plan, occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted common stock automatically lapse.

For a further discussion of these plans, as well as plans that have been approved by our stockholders, see our proxy statement for the 2003 Annual Meeting of Stockholders, which has been incorporated by reference into this Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$12,194	$13,649	$19,271	$13,318	$13,399
Income (loss) from continuing operations before preferred stock dividends[1]	(1,289)	72	1,237	251	176
Income (loss) from continuing operations available to common stockholders[1]	(1,289)	72	1,237	251	170
Basic earnings (loss) per common share from continuing operations	$ (2.30)	$ 0.14	$ 2.50	$ 0.51	$ 0.35
Diluted earnings (loss) per common share from continuing operations	$ (2.30)	$ 0.14	$ 2.43	$ 0.51	$ 0.34
Cash dividends declared per common share[2]	$ 0.87	$ 0.85	$ 0.82	$ 0.80	$ 0.76
Basic average common shares outstanding	560	505	494	490	487
Diluted average common shares outstanding	560	516	513	497	495

	As of December 31,				
	2002	2001	2000	1999	1998
	(In millions)				
Financial Position Data:					
Total assets	$46,224	$48,546	$46,903	$32,090	$26,759
Long-term financing obligations	16,106	12,891	11,603	10,021	7,691
Non-current notes payable to affiliates	201	368	343	—	—
Securities of subsidiaries	3,420	4,013	3,707	2,444	999
Stockholders' equity	8,377	9,356	8,119	6,884	6,913

(1) In March 2003, we entered into an agreement in principle to settle claims associated with the western energy crisis of 2000 and 2001. We also incurred losses related to impairments of assets and equity investments and incurred restructuring charges related to industry changes. We also incurred a ceiling test charge on our full cost natural gas and oil properties. During 2001, we merged with The Coastal Corporation and incurred costs and asset impairments related to this merger. In 1999, we incurred $557 million of merger charges primarily related to our merger with Sonat, Inc. and incurred $352 million of ceiling test charges. In 1998, we incurred $1,035 million of ceiling test charges. For a further discussion of events affecting comparability of our results in 2002, 2001 and 2000, See Item 8, Financial Statements and Supplementary Data, Notes 2, 4, 5, 6 and 7.

(2) Cash dividends declared per share of common stock represent the historical dividends declared by El Paso for all periods presented.

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

Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed beginning on page 76.

Overview

We are an energy company whose operations encompass natural gas and oil production; gathering, processing and interstate and intrastate transmission of natural gas; power generation; petroleum refining; and energy trading. Our business is divided into four distinct business segments: Pipelines, Production, Field Services and Merchant Energy.

During the last five years, we experienced substantial growth from mergers and acquisitions, and organic growth of our marketing and trading and global power businesses. Growth through mergers and acquisitions has included significant transactions, such as our DeepTech International acquisition in 1998, Sonat merger in 1999, and the Coastal merger in 2001. These transactions, the growth of trading and power activities and the capital needs of our other businesses required substantial financial resources. During this five-year period, we frequently accessed the capital markets to fund our growth through a wide variety of financings.

During 2002, we experienced dramatic changes in our industry as well as in the financial markets on which we rely, and we continue to operate in a very challenging environment. In response to industry events, the credit rating agencies, including Moody's and Standard & Poor's, re-evaluated the ratings of companies involved in energy trading activities. As a result, the ratings of many of the largest participants in the energy trading industry, including us, were downgraded to below investment grade. Several experienced significant financial distress. Also impacting us was a preliminary decision reached by a FERC ALJ that one of our subsidiaries withheld pipeline capacity from the California market during 2000 and 2001. Reacting to the changes in the market, our leverage and a preliminary decision related to our California matters, Moody's and Standard & Poor's initiated a series of ratings actions lowering our senior unsecured debt rating to Caa1 and B (both ''below investment grade'' ratings), and we remain on negative outlook.

Several negative outcomes resulted from these downgrades. First, cash generated in 2002 from the sales of assets, which had originally been identified for debt reductions, was instead: required to be posted as additional cash collateral in connection with our commercial trading activities; paid to satisfy financial guarantees; and used to retire other arrangements. Additionally, our access to capital markets and commercial paper markets became much more restricted because of our lower credit ratings. Finally, the credit downgrades resulted in the net cash generated by assets and businesses that collateralize two of our minority interest financing arrangements being largely unavailable to us for general corporate purposes. Instead, we were required to use this cash to redeem preferred securities issued in connection with those arrangements and for the operation of those assets and businesses. In March 2003, we issued a $1.2 billion two-year term loan. The proceeds were used to retire the outstanding amounts under the Trinity River preferred interest financing arrangement, partially freeing up these cash usage restrictions. For a further discussion of this redemption, see Item 8, Financial Statements and Supplementary Data, Note 19.

Since the fourth quarter of 2001, we have taken several steps to address the issues affecting us, and we have made significant progress in our plans to meet the demands on our liquidity and to strengthen our capital structure.

Some of our more significant accomplishments include:

- The sale of over $2.5 billion of equity or equity-linked securities;
- The completion or execution of contracts for the sale of over $5.5 billion of non-core assets and investments;

- The removal of rating triggers from over $4 billion of our investment and financing programs, which, because of our credit rating downgrades, would have resulted in the issuance of our stock or the liquidation of assets, the proceeds from which would have been used to repay those arrangements;

- The issuance of $700 million in senior unsecured notes at Southern Natural Gas Company ($400 million) and ANR Pipeline Company ($300 million);

- The completion in March 2003 of a new $1.2 billion term loan, which enabled the retirement of our Trinity River preferred interest financing arrangement and eliminated the cash restrictions and accelerated amortization of that arrangement;

- The establishment of an exit strategy for our trading business, including the planned orderly liquidation of our existing trading portfolio;

- The substantial reduction of our credit exposure to our LNG business;

- The repayment of over $1.9 billion of financial obligations, including Electron and Trinity River; and

- The achievement of the Western Energy Settlement in March 2003, which was designed to resolve our principal exposure relating to the western energy crisis while minimizing the impact on our current liquidity.

On February 5, 2003, we announced our 2003 Operational and Financial Plan. This plan is based on five key principles:

- Preserve and enhance the value of our core businesses;

- Exit non-core businesses quickly but prudently;

- Strengthen and simplify the balance sheet while maximizing liquidity;

- Aggressively pursue additional cost reductions; and

- Continue to work diligently to resolve litigation and regulatory matters.

In the following sections of our Management's Discussion and Analysis, we address these events and our outlook in greater detail. In the section entitled Liquidity and Capital Resources, we discuss the impact of changes in our credit standing and our current liquidity, including our ability to generate cash from operations and capital market transactions. In the section entitled Off-Balance Sheet Arrangements and Contractual Obligations, we discuss the various financing and contractual arrangements in which we are involved that commit us under guarantees and other commercial and contractual obligations. In Results of Operations, we analyze operating results for each of our business segments and identify unusual and infrequent events that have impacted and, in some cases, may continue to impact, the operations of our business segments.

Our discussions of Liquidity and Capital Resources, Off-Balance Sheet Arrangements and Contractual Obligations and Results of Operations are based on our consolidated financial statements, which have been prepared through the application of accounting principles that are generally accepted in the U.S. The preparation of our financial statements reflect the selection and application of accounting policies, many of which require us to use assumptions, estimates and judgments that involve complex processes. Actual results can, and often do, differ from these estimates. Beginning on page 70 is a discussion of our Critical Accounting Policies, which discuss those policies that are significant to our financial position and operating results that are presented in our financial statements. You should also read our significant accounting policies in Item 8, Financial Statements and Supplementary Data, Note 1, to understand all of the policies that impact our financial presentation included in this discussion and analysis and in the presentation of our financial statements as a whole.

Liquidity and Capital Resources

Liquidity

Overview of Current Liquidity

We rely on cash generated from our internal operations as our primary source of liquidity, as well as available credit facilities, bank financings, asset sales and the issuance of long-term debt, preferred securities and equity securities. From time to time, we have also used structured financings sometimes referred to as off-balance sheet arrangements. We expect that our future funding for working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources. Each of these sources are impacted by factors that influence the overall amount of cash generated by us and the capital available to us. For example, cash generated by our business operations may be impacted by changes in commodity prices or demands for our commodities or services due to weather patterns, competition from other providers or alternative energy sources. Collateral demands or recovery of collateral posted are impacted by natural gas prices, hedging levels and our credit quality and that of our counterparties. Liquidity generated by future asset sales may depend on the overall economic conditions of the industry served by these assets, the condition and location of the assets and the number of interested buyers. In addition, our credit ratings or general market conditions can restrict our ability to access capital markets, which can have a significant impact on our liquidity.

The following tables, which reflect our available liquidity at the beginning of the year and estimated sources and uses of liquidity throughout 2003, indicate the adequacy of our liquidity to meet our immediate needs.

At the beginning of 2003, our available liquidity was as follows (in billions):

Sources	
Available cash	$1.1
Availability under 364-day bank facility[1]	1.5
Availability under multi-year bank facility[1][2]	0.5
Net available liquidity	$3.1

[1] Our 364-day bank facility matures in May 2003, with amounts outstanding at that time becoming due in May 2004, and our multi-year bank facility matures in August 2003.

[2] An additional $0.5 billion was drawn in February 2003.

Other sources of cash we expect for 2003 include (in billions):

Cash flow from operating activities before working capital and non-working capital changes	$2.1 - $2.4
Return of working capital	0.3
Debt issuances[1]	3.1
Other financings	0.4
Asset sales[2]	3.1 - 3.3
Total	$9.0 - $9.5

[1] Issuances of $1.9 billion occurred in March 2003.

[2] As of March 31, 2003, we have completed or executed contracts for the sale of over $1.7 billion of non-core assets and investments.

For 2003, our anticipated cash needs include (in billions):

Debt repayments	$3.0
Minority interest redemptions[1]	1.6
Other financing obligations[2]	1.2
Maintenance capital	1.8
Discretionary capital	0.7
Dividends	0.2
Anticipated cash needs	$8.5

(1) Includes redemption of Trinity River preferred interest of $980 million that occurred in the first quarter of 2003.

(2) Includes repayment of Limestone notes of $1 billion that occurred in March 2003 and the purchase of Limestone's equity for $175 million that is expected to occur in May 2003.

Our anticipated requirements may change significantly, and our analysis is intended to provide you with an understanding of our cash needs, both required and discretionary, to better understand our liquidity outlook. The factors that could impact our outlook are identified beginning on page 76.

Overview of Cash Flow Activities for 2002

For the years ended December 31, 2002 and 2001, our cash flows are summarized as follows:

	2002	2001
	(In millions)	
Cash flows from operating activities		
Net income (loss)	$(1,467)	$ 93
Non-cash income adjustments	3,516	2,320
Cash flows before working capital and non-working capital changes	2,049	2,413
Working capital changes	(1,436)	1,914
Non-working capital changes and other	(177)	(207)
Cash flows from operating activities	436	4,120
Cash flows from investing activities	(1,255)	(5,023)
Cash flows from financing activities	1,272	1,300
Change in cash	$ 453	$ 397

During the year ended December 31, 2002, our cash and cash equivalents increased by approximately $0.5 billion to approximately $1.6 billion. We generated a substantial amount of cash from various sources, including cash flows from our principal operations, sales of assets and financing transactions, including long-term debt and equity securities issuances. We also used a major portion of that cash to fund our capital expenditures, to repay maturing financial obligations and to meet the increased demand for cash collateral as a result of our credit downgrade.

In summary, we generated cash from our principal business operations (before working capital demands and other changes) of $2.0 billion. We also raised $5.4 billion of cash through the issuance of debt and equity securities and borrowings under our revolving credit facility. Cash proceeds from the sale of assets and investments amounted to approximately $2.9 billion. With the cash we received from these sources, we invested approximately $4.0 billion in our property, plant and equipment and equity investments and we paid $2.8 billion on maturing long-term debt and other obligations. Additionally we paid $0.5 billion in dividends and $0.9 billion to redeem minority and preferred interests. We also met net working capital and other demands of $1.6 billion primarily for margin payments related to our energy trading activities, hedging activities on our natural gas production and other collateral requirements. A more detailed analysis of our cash flows from operating, investing and financing activities follows.

Cash From Operating Activities

We generated almost $2.0 billion in cash from operations in 2002 before working capital and other changes, as compared to $2.4 billion in 2001. Net cash provided by operating activities was $0.4 billion for the year ended December 31, 2002, compared to net cash provided by operating activities of $4.1 billion for the same period in 2001.

Margin call requirements and trading activities have been a volatile source, or use, of working capital for us, and are the primary reasons for the significant differences in our 2002 operating cash flows compared to 2001. Where we had substantial net cash outflows for margins in 2002 of $0.9 billion, we had net cash inflows in 2001 for margins of almost $0.3 billion. Operating cash flows in 2002 also reflected significantly lower cash inflows from settlements of trading positions of $0.3 billion compared to $1.5 billion in 2001.

Our margin positions are significantly impacted by two factors: credit and commodity prices. Following our downgrade, credit extended to us by our counterparties was lowered requiring us to post additional margins. Many of our counterparties also posted letters of credit with us requiring us to return their margin deposits. In addition, the impact on our operating cash flows from changes in commodity prices depends on whether our hedged prices are above or below market prices. For most of 2001, our hedged prices were above market, which resulted in margins being deposited with us. When our hedged prices go below market, as they did in 2002, we are required to make margin deposits. However, the margin deposits will be recovered when we sell the underlying commodities and settle the positions or when natural gas prices decrease. At December 31, 2002, we held $0.1 billion of cash and $0.4 billion of letters of credit as collateral from third parties related to our price risk management activities and have provided $1.0 billion of cash and $0.2 billion letters of credit to third parties related to those activities.

Cash From Investing Activities

Net cash used in our investing activities was $1.3 billion for the year ended December 31, 2002. Our investing activities consisted primarily of capital expenditures and equity investments of $4.0 billion offset by net proceeds from sale of assets and investments and cash received for repayment of notes receivable of $2.9 billion. Our capital expenditures and equity investments included the following (in billions):

Production exploration, development and acquisition expenditures	$2.2
Pipeline expansion, maintenance and integrity projects	0.9
Investments in and net advances to unconsolidated affiliates	0.3
Other (primarily petroleum and power projects)	0.6
Total capital expenditures and equity investments	$4.0

Cash received from our investing activities includes $2.9 billion from the sale of assets and investments. Our asset sales proceeds are primarily attributable to the sale of natural gas and oil properties in Texas, Colorado, Utah and western Canada for $1.3 billion, the sales of Texas and New Mexico midstream assets for $0.5 billion and San Juan assets of $0.4 billion to El Paso Energy Partners and the sale of other power, petroleum and processing assets of $0.7 billion.

Cash From Financing Activities

Net cash provided by our financing activities was $1.3 billion for the year ended December 31, 2002. Cash provided from our financing activities included the net proceeds from the issuance of long-term debt of $4.3 billion, including $0.8 billion of nonrecourse debt issued in connection with our Utility Contract Funding, L.L.C. (UCF) power contract restructuring and $0.6 million associated with an equity security units issuance. Additionally, we issued $1.0 billion of common stock. We also received net proceeds under our commercial paper and short-term credit facilities of $0.2 billion. Cash used by our financing activities included payments made to retire third party long-term debt and other financing obligations of $2.3 billion. We also redeemed $700 million of preferred securities previously issued by our subsidiaries and made other minority interest payments of $161 million, primarily to Chaparral which holds a 16 percent minority interest in the UCF project. Further, we repaid $513 million of notes payable to affiliates and paid dividends of $470 million. Also, during the year ended December 31, 2002, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of approximately $25 million on our Series A cumulative preferred stock that accrues at a rate of 8¼% per year (2.0625% per quarter).

A summary of our significant borrowing and repayment activities during 2002 and 2003 is presented below. These amounts do not include borrowings or repayments on our short-term financing instruments with an original maturity of three months or less, which are referred to above under cash from financing activities.

Issuances

Company	Interest Rate	Principal	Net Proceeds[1]	Due Date
		(In millions)		
2002				
El Paso	6.14%-7.875%	$2,707[2]	$2,580	2007-2032
SNG	8.00%	300	297	2032
EPNG	8.375%	300	297	2032
TGP	8.375%	240	238	2032
Mohawk River Funding IV[3]	7.75%	92	90	2008
Utility Contract Funding[3]	7.944%	829	792	2016
Total		$4,468	$4,294	
2003				
ANR	8.875%	$ 300	$ 288	2010
SNG	8.875%	400	385	2010
EPC[4]	LIBOR+4.25%	1,200	1,179	2004-2005
Total		$1,900	$1,852	

(1) Net proceeds were primarily used to repay maturing long-term debt, short-term borrowings, for repayment of intercompany borrowings, to meet capital requirements of the borrower, to redeem preferred interests in consolidated subsidiaries and for general corporate purposes.

(2) Includes $82 million change in value on our €500 million Euro notes from May 2002 to December 2002 due to a change in the Euro to U.S. dollar foreign currency exchange rate.

(3) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to our other consolidated subsidiaries. The Mohawk River Funding IV financing relates to our Capitol District Energy Center Cogeneration Associates power restructuring transaction, and the Utility Contract Funding financing relates to our Eagle Point Cogeneration power restructuring transaction.

(4) We have collateralized this term loan with natural gas and oil reserves of approximately 2.3 Tcfe. The minimum LIBOR rate is 3.5%.

Retirements

Company	Interest Rate	Principal	Net Payments	Due Date
		(In millions)		
2002				
El Paso	6.75%-8.78%	$ 109	$ 89[1]	2002-2011
El Paso CGP	6.20%-8.125%	720	284[2]	2002-2004
El Paso CGP	Variable	1,262	1,262	2002-2028
El Paso Tennessee	7.88%	12	12	2002
SNG	7.85%-8.625%	200	200	2002
EPNG	7.75%	215	215	2002
El Paso Oil and Gas Resources	Variable	215	216	2002-2005
Other	Various	51	50	2002
Total		$2,784	$2,328	
2003				
El Paso CGP	4.49%	$ 240	$ 240	2004
Other	Various	47	47	2003
Total		$ 287	$ 287	

(1) We bought back $109 million of our bonds in the open market during the second half of the year for $89 million. We anticipate we will continue to repurchase debt, subject to available liquidity and ongoing market opportunities.

(2) Includes exchange of $435 million of senior debentures for common stock as discussed below.

In June 2002, we issued 51.8 million shares of our common stock at a public offering price of $19.95 per share. Net proceeds from the offering were approximately $1 billion and were used to repay short-term borrowings and other financing obligations and for general corporate purposes.

In June 2002, we issued 11.5 million, 9% equity security units. Equity security units consist of two securities: (i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86% and that requires its holder to buy our common stock to be settled on August 16, 2005, and (ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14% beginning August 16, 2002. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders' obligation to purchase shares of our common stock under the purchase contracts.

When the purchase contracts are settled in 2005, we will issue common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 24 million shares and up to a maximum of 28.8 million shares on the settlement date, depending on our average stock price. We recorded approximately $43 million of other non-current liabilities to reflect the present value of the quarterly contract adjustment payments that we are required to make on these units at an annual rate of 2.86% of the stated amount of $50 per purchase contract with an offsetting reduction in additional paid-in capital. The quarterly contract adjustment payments are allocated between the liability recognized at the date of issuance and additional paid-in capital based on a constant rate over the term of the purchase contracts.

Fees and expenses incurred in connection with the equity security units offering were allocated between the senior notes and the purchase contracts based on their respective fair values on the issuance date. The amount allocated to the senior notes is recognized as interest expense over the term of the senior notes. The amount allocated to the purchase contracts is recorded as additional paid-in capital.

In August 2002, we issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES[sm] program. In return for the issuance of the stock, we received approximately

$25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004 that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

Credit Facilities

We have historically used commercial paper programs to manage our short-term cash requirements. Under our programs we could borrow up to $3 billion through a combination of individual corporate, TGP and EPNG commercial paper programs of $1 billion each. However, as a result of our credit downgrade, we are not currently issuing commercial paper to meet our liquidity needs.

In May 2002, we renewed our existing $3 billion 364-day revolving credit and competitive advance facility. EPNG and TGP are also designated borrowers under this facility and, as such, are jointly and severally liable for any amounts outstanding. This facility matures in May 2003 and provides that amounts outstanding on that date are not due until May 2004. We also maintain a 3-year, $1 billion, revolving credit and competitive advance facility under which we can conduct short-term borrowings and other commercial credit transactions. In June 2002, we amended this facility to permit us to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003. Our subsidiaries, El Paso CGP Company (formerly Coastal), EPNG and TGP, are designated borrowers under the facility and, as such, are jointly and severally liable for any amounts outstanding. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of December 31, 2002, borrowings under the facility have a rate of LIBOR plus 1.00% plus a 0.25% utilization fee. At December 31, 2002, we had $1.5 billion outstanding under the $3 billion facility and issued approximately $456 million letters of credit under the $1 billion facility. In February 2003, we borrowed $500 million under the $1 billion facility.

We are currently negotiating an amendment to our $3 billion 364-day revolving credit facility. If we are successful in negotiating this amendment, we expect the terms and conditions of the amended revolving credit facility to include an extension of the maturity date, an increase in the unused commitment fee and margin, collateral to support the financing, and new and amended financial ratios and covenants. It is expected that ANR, TGP and EPNG would also be borrowers under this facility. We are also currently negotiating an amendment to our $1 billion multi-year facility, which we expect to be conformed to the amended $3 billion 364-day revolver, except for the commitment amount, the identity of lenders and the maturity.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which 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.

Restrictive Covenants. We and our subsidiaries have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross-payment default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our revolving credit facilities, the significant debt covenants and cross defaults are:

(a) the ratio of consolidated debt and guarantees to capitalization (excluding certain project financing and securitization programs and other miscellaneous items as defined in the agreement) cannot exceed 70 percent;

(b) the consolidated debt and guarantees (other than excluded items) of our subsidiaries cannot exceed the greater of $600 million or 10 percent of our consolidated net worth;

(c) we or our principal subsidiaries cannot permit liens on the equity interest in our principal subsidiaries or create liens on assets material to our consolidated operations securing debt and guarantees (other than excluded items) exceeding the greater of $300 million or 10 percent of our consolidated net worth, subject to certain permitted exceptions; and

(d) the occurrence of an event of default for any non-payment of principal, interest or premium with respect to debt (other than excluded items) in an aggregate principal amount of $200 million or more; or the occurrence of any other event of default with respect to such debt that results in the acceleration thereof.

We were in compliance with the above covenants as of the date of this filing, including our ratio of debt to capitalization (as defined in our credit facilities), which was 63.2% at December 31, 2002.

We have also issued various guarantees securing financial obligations of our subsidiaries and unconsolidated affiliates with similar covenants as in the above credit facilities.

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also maintain a $30 million cross-acceleration provision. El Paso CGP's net worth at December 31, 2002, was $4.3 billion.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These cross-acceleration provisions generally state that if an event of default occurs that exceeds $5 million, then amounts outstanding for the securities that contain these indentures also become due and payable.

Available Capacity Under Shelf Registration Statements

In February 2002, we filed a new shelf registration statement with the SEC that allows us to issue up to $3 billion in securities. Under this registration statement, we can issue a combination of debt, equity and other instruments, including trust preferred securities of two wholly owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities. As of December 31, 2002, we had $818 million remaining capacity under this shelf registration statement.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2002, we had outstanding letters of credit of approximately $852 million versus $465 million as of December 31, 2001. The increase is primarily due to the issuance of letters of credit in connection with the management of our trading activities. At December 31, 2002, $456 million of our outstanding letters of credit were supported by our revolving credit facility.

Off-Balance Sheet Arrangements and Contractual Obligations

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. The following discusses first those contingent obligations, often referred to as off-balance sheet arrangements, that are not part of the consolidated obligations reflected in our financial statements. Second, we present aggregated information on our contractual cash obligations, some of which are reflected in our financial statements, such as short and long-term debt, and others, such as operating leases and capital commitments, which are not reflected in our financial statements.

Off-Balance Sheet Arrangements

The following table summarizes our off-balance sheet arrangements by date of expiration as of December 31, 2002. These commitments are discussed in further detail below:

Off-Balance Sheet Arrangements	Total Amounts Committed
	(In millions)
Credit facilities	$ 300
Guarantees	2,508
Residual value guarantees	570
Total	$3,378

Credit Facilities

We have a credit facility with Gemstone that allows Gemstone to borrow up to $300 million from us at a variable interest rate, which was 6.8% at December 31, 2002. Gemstone owed us $25 million under this facility as of December 31, 2002, and did not utilize this facility in 2001. We earned less than $1 million of interest income from this facility in 2002 and 2001.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas.

As of December 31, 2002, we had approximately $2.5 billion of both financial and performance guarantees outstanding. Of this amount, approximately $1.0 billion relates to our Chaparral investment and $950 million relates to our Gemstone investment, both of which are discussed below. The remaining $558 million relates to other global power equity investments, including some of the projects under Chaparral and Gemstone, and pipeline and petroleum activities.

Chaparral. We entered into the Chaparral investment (also referred to as Electron) in 1999 to expand our domestic power generation business. At the time Chaparral was formed, we were interested in participating in the deregulation of the power industry that was occurring across the U.S. Our objective was to acquire a number of nonregulated power plants that were built because of PURPA. With these plants and their related power contracts, there were opportunities to improve existing income and cash flows by lowering the cost of power sold to the regulated utility under the plant's power sales agreement. This was accomplished by purchasing the power supplied to the utility from the wholesale power market, rather than generating power at the plant. Consequently, Chaparral's investors, and our shareholders would benefit from these improved economics. In establishing this business, there were a number of objectives we hoped to achieve, including:

- *Portfolio management.* Our goal was to establish an investment, not unlike a mutual fund or other investment portfolio, that held a number of assets, and on which we could earn a performance-based management fee determined by the value we delivered to all investors. Furthermore, this portfolio approach allowed us to reduce the volatility of earnings and enhance the cash flows in this business.

- *Flexibility and efficiency.* Given the complexity of acquiring, managing and renegotiating existing power contracts, we sought investors whose business strategies were aligned with ours, to allow us maximum flexibility and efficiency.

- *Liability segregation and separation of non-recourse financing and other liabilities from our balance sheet.* Many of the power projects in which we would hold interests were funded through partnerships and non-recourse project financings which, on average, had higher leverage in terms of their debt to total equity. Had this business been developed on our balance sheet, it could have negatively impacted our ratios and possibly our credit ratings. Consequently, we did not want to reflect this higher leverage in our overall capitalization given that the debt is non-recourse to us. Furthermore, separation of these entities and their related debt and other obligations more appropriately reflected the nature of the recourse, which was solely to the projects.

Chaparral's corporate structure is a limited liability company that, at December 31, 2002, was owned approximately 20 percent by us and approximately 80 percent by an unaffiliated investor, Limestone. Limestone is capitalized by private equity contributions of $150 million from a group of unrelated financial investors through Credit Suisse First Boston Corporation and $1 billion of senior secured notes issued to institutional investors. Limestone is controlled by subsidiaries or affiliates of Credit Suisse First Boston Corporation.

In March 2003, we notified Limestone that we will exercise our right under the partnership agreements to purchase all of the outstanding third party equity in Limestone on May 31, 2003, for $175 million. On March 31, 2003, we contributed $1 billion to Limestone in exchange for a non-controlling interest. Limestone used the proceeds from the contribution to pay off $1 billion of the notes that matured on that date. With this note repayment, we cancelled our $1 billion guarantee related to our Chaparral investment. Following our additional investment of $1 billion in Limestone, our effective ownership of Chaparral increased to approximately 90 percent, but neither our rights nor the rights of Limestone to participate in the operating decisions of Chaparral changed. As a result, we continue to account for our investment in Chaparral under the equity method. We will consolidate Chaparral upon the purchase of the remaining third party equity interest in Limestone, which we expect to occur in May 2003. At that time, we will record the acquired assets and liabilities at their fair values. The fair value of assets and liabilities acquired will be impacted by changes in the unregulated power industry as a whole, as well as by changes in regional power prices in the U.S. Any excess of the proceeds paid over the fair value of net assets acquired will be reflected as goodwill. Goodwill is not subject to amortization but it will be tested for impairment. While we cannot currently estimate the ultimate amount of goodwill that will be recorded, we believe goodwill of up to $450 million may result. If goodwill were to be fully impaired we would report a charge to earnings of approximately $300 million after income taxes. If, on the other hand, the carrying amount of the acquired assets and liabilities, when aggregated with our other power assets and liabilities, is below the fair value of the reporting unit (reporting unit being defined as the entire global power business), there would be no impairment of goodwill.

As of December 31, 2002, Chaparral had $4.2 billion of total assets and $1.8 billion of consolidated third party debt. Chaparral's debt is related to specific assets it owns or has interests in, and is recourse solely to those assets. Our equity investment in Chaparral at December 31, 2002 was $256 million, but we also had additional net receivables from Chaparral which totaled $448 million, resulting in a total net investment in Chaparral of $704 million at December 31, 2002.

For a further discussion of Chaparral and its activities, see Item 8, Financial Statements and Supplementary Data, Note 26.

Gemstone. We entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. Gemstone was established to accomplish the following objectives:

- *Portfolio management.* Like Chaparral, our goal was to establish an investment portfolio that held a number of assets in which we participate in the earnings of these equity investments. Unlike Chaparral's performance-based management fee, however, our primary objective in this investment was to have the flexibility to acquire or sell additional assets into or out of the overall portfolio of projects.

- *Flexibility and efficiency.* Given the complexity of acquiring, operationally managing and negotiating power contracts with foreign governments, we sought investors whose interests were primarily financial (return driven), to allow us maximum flexibility and efficiency. Furthermore, this allowed us to share risk in a foreign country and partially mitigate our foreign investment risk.

Gemstone is a generic term used to describe several entities. The first is the joint venture in which we have an equity investment named Diamond Power Ventures, LLC (Diamond). Diamond is owned by us and Gemstone Investor. Gemstone Investor is 100 percent owned by a subsidiary of Rabobank International, which, in addition to its $50 million equity investment, issued $950 million of senior secured notes to institutional investors. Gemstone Investor used the entire $1 billion to (a) invest up to $700 million in Diamond, and (b) purchase a $300 million preferred interest in a company called Topaz Power Ventures LLC (Topaz), our consolidated subsidiary. Topaz indirectly owns and operates two Brazilian power plants. We account for Gemstone Investor's preferred investment in Topaz as minority interest. We do not consolidate Diamond, which owns three power plants in Brazil.

Gemstone owns interests in five power generation facilities in Brazil with a total power generation capacity of 2,184 megawatts. As of December 31, 2002, Gemstone had total assets of $1.7 billion, including a $304 million investment in Topaz, and $122 million in receivables from us. Our total investment in Gemstone at December 31, 2002, was $663 million, excluding the payables of $304 million and minority interest of $122 million mentioned above.

Our consolidated subsidiary, Gemstone Administracao Ltda, serves as the managing member of Diamond and provides management services to Diamond under a fixed-fee administrative services agreement. The fixed fee reimburses us for legal, accounting and general and administrative expenses incurred on behalf of Diamond.

In January 2003, Rabobank notified us that they planned to remove us as manager of Gemstone, in accordance with their rights under our partnership agreements. We, in turn, notified Rabobank that we were exercising our right under the partnership agreements to purchase all of Rabobank's $50 million of equity in Gemstone. We will consolidate Gemstone upon the purchase of Rabobank's equity in Gemstone by April 2003, unless we replace them with a new partner.

For a further discussion of Gemstone and its activities, see Item 8, Financial Statements and Supplementary Data, Note 26.

Residual Value Guarantees

Under two of our operating leases, we have provided residual value guarantees to the lessor. Under the leases, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is typically equal to the outstanding loan amounts owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The levels of our residual value guarantees range from 86.2 percent to 89.9 percent of the original cost of the leased assets. Accounting for these residual value guarantees will be impacted effective July 1, 2003, by our adoption of the new accounting rules on consolidations. For a discussion of the accounting impact of these new rules, see *New Accounting Pronouncements Issued But Not Yet Adopted* below.

As of December 31, 2002, we had purchase options and residual value guarantees associated with operating leases for the following assets:

Asset Description	Purchase Option	Residual Value Guarantee	Lease Expiration
	(In millions)		
Lakeside Technology Center telecommunications facility	$275	$237	2006
Facility at Aruba refinery	370	333	2006

Contractual Cash Obligations

The following table summarizes our contractual cash obligations as of December 31, 2002, for each of the years presented.

Contractual Cash Obligations	2003	2004	2005	2006	2007	Thereafter	Total
				(In millions)			
Long-term debt[1]	$ 575	$ 586	$ 610	$1,234	$1,133	$12,590	$16,728
Preferred interests of consolidated subsidiaries[2]	400	900	380	950	—	625	3,255
Western Energy Settlement[3]	100	132	129	67	67	1,072	1,567
Operating leases[4]	174	147	113	89	56	265	844
Transportation and storage capacity[5]	169	175	151	139	126	674	1,434
Commodity purchases[6]	4	3	3	3	3	20	36
Obligations to affiliates[7]	189	10	12	6	—	173	390
Other commitments and purchase obligations[8][9]	462	190	59	19	9	86	825
Total contractual cash obligations	$2,073	$2,143	$1,457	$2,507	$1,394	$15,505	$25,079

(1) See Item 8, Financial Statements and Supplementary Data, Note 18.

(2) See Item 8, Financial Statements and Supplementary Data, Note 19.

(3) See Item 8, Financial Statements and Supplementary Data, Notes 2 and 20.

(4) We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2003 until 2053.

(5) Amounts include payments for firm access to natural gas transportation and storage capacity.

(6) Amounts include purchase commitments for electricity that are not part of our trading activities.

(7) Amounts include obligations of $252 million to Chaparral, $122 million to Gemstone and $16 million to other affiliates. Our obligation to Chaparral consists of $79 million of debt securities and $173 million of contingent interest promissory notes. The debt securities are payable on demand and carry a fixed interest rate of 7.443%. The contingent interest promissory notes carry a variable interest rate not to exceed 12.75% and mature in 2019 through 2021. Our obligation to Gemstone consists of $122 million of debt securities, which are payable on demand and carry a fixed interest rate of 5.25%.

(8) Amounts include primarily other purchase and capital commitments such as maintenance contracts, engineering, procurement and construction costs.

(9) Other commitments exclude $2.5 billion associated with our LNG ship charter agreement. These obligations were restructured in March 2003 and resulted in issuance of letters of credit equal to $120 million, which was fully collateralized by cash.

Results of Operations

We use earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for earnings on equity investments, capitalized returns on equity and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, income taxes, discontinued operations, extraordinary items and cumulative effect of accounting changes. The following is a reconciliation of our operating results to EBIT and income (loss) from continuing operations for the years ended December 31:

	2002	2001	2000
		(In millions)	
Operating revenues	$ 12,194	$ 13,649	$ 19,271
Operating expenses	(12,266)	(12,728)	(16,856)
Operating income (loss)	(72)	921	2,415
Earnings (losses) from unconsolidated affiliates	(234)	450	428
Minority interest in consolidated subsidiaries	(58)	(2)	—
Other income	248	396	234
Other expenses	(109)	(136)	(57)
EBIT	(225)	1,629	3,020
Interest and debt expense	(1,400)	(1,156)	(1,040)
Returns on preferred interests of consolidated subsidiaries	(159)	(217)	(204)
Income taxes	495	(184)	(539)
Income (loss) from continuing operations	$ (1,289)	$ 72	$ 1,237

We believe EBIT is a useful measurement for our investors because it provides information that can be used to evaluate the effectiveness of our businesses and investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow.

Overview of Results of Operations

Below are our results of operations (as measured by EBIT), by segment for each of the years ended December 31. These results include the impacts of restructuring and merger-related costs, asset impairments, and other charges (including our estimated Western Energy Settlement) and gains on sales of assets, which are discussed further in Item 8, Financial Statements and Supplementary Data, Notes 2, 4, 5 and 26 See Item 8, Financial Statements and Supplementary Data, Note 24, for a reconciliation of our operating results to EBIT by segment.

EBIT by Segment	2002	2001	2000
		(In millions)	
Pipelines	$ 818	$ 1,038	$1,323
Production	534	920	609
Field Services	287	195	214
Merchant Energy	(1,638)	904	930
Segment EBIT	1	3,057	3,076
Corporate and other	(226)	(1,428)	(56)
Consolidated EBIT from continuing operations	$ (225)	$ 1,629	$3,020

Segment Results

Our four segments: Pipelines, Production, Field Services and Merchant Energy are strategic business units that offer a variety of different energy products and services, each requires different technology and marketing strategies. Below is a discussion and analysis of the operating results of each of our business segments. These results include the impact of our significant acquisitions and dispositions, the restructuring and merger-related costs, asset impairments and other charges discussed above for all years presented.

Pipelines

Our Pipelines segment consists of interstate natural gas transmission, storage, gathering and related services in the U.S. and internationally. Our interstate natural gas transportation systems face varying degrees of competition from other pipelines, as well as from alternate energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil. In addition, some of our customers have shifted from a traditional dependence solely on long-term contracts to a portfolio approach which balances short-term opportunities with long-term commitments. The shift is due to changes in market conditions and competition driven by state utility deregulation, local distribution company mergers, new supply sources, volatility in natural gas prices, demand for short-term capacity and new markets to supply power plants.

We are regulated by the FERC, which regulates the rates we can charge our customers. These rates are a function of our costs of providing services to our customers, and include a return on our invested capital. As a result, our financial results have historically been relatively stable; however, they can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the credit-worthiness of our customers. In addition, our ability to extend our existing customer contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

As discussed in Item 8, Financial Statements and Supplementary Data, Note 20 under the subheading *Rates and Regulatory Matters,* the FERC issued an order related to the allocation of capacity on the EPNG system. This order required EPNG to:

- give reservation charge credits prospectively to its firm shippers if it fails to schedule the shippers' confirmed volumes (except in the case of force majeure);
- refrain from entering into new firm contracts or remarketing turned back capacity under contracts terminating or expiring after May 31, 2002; and
- add additional compression to its Line 2000 project increasing the capacity by 320 MMcf/d without the opportunity to recover these costs in its rates until its next rate case which will be effective January 1, 2006.

Our Pipelines segment's future results of operations will be impacted as a result of the capacity allocation proceeding. The order prohibits EPNG from remarketing approximately 471 MMDth/d of its capacity, of which approximately 200 MMDth/d was rejected by Enron Corp. in May 2002 in its bankruptcy proceeding. The remaining 271 MMDth/d relates to capacity that EPNG is unable to remarket from contracts that expired within the time frame specified under the FERC's order. Prior to the rejection and expiration of the 471 MMDth/d contracts, EPNG was earning approximately $3.5 million per month, net of revenue credits, related to this capacity. EPNG has requested rehearing of the September 20 FERC order relating to this and other aspects of the order. This request for rehearing is pending before the FERC.

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. Enron's subsidiaries had transportation contracts on several of our pipeline systems (including the EPNG contract discussed above). All these transportation contracts have now been rejected, and our pipeline subsidiaries have filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included

$18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts, which EPNG is prohibited from remarketing under the capacity allocation orders discussed above. We have fully reserved for all amounts due from Enron through the date the contracts were rejected, and we have not recognized any revenues from these contracts since the rejection date.

In November 2002, we sold 12.3 percent of our 14.4 percent equity interest in the Alliance pipeline system, and net proceeds were $141 million. We completed the sale of our remaining equity interest in Alliance during the first quarter of 2003. Income earned on our investment in Alliance for the year ended December 31, 2002 and 2001, was approximately $21 million and $23 million.

Results of operations of the Pipelines segment were as follows for each of the three years ended December 31:

Pipelines Segment Results	**2002**	**2001**	**2000**
	(In millions, except volume amounts)		
Operating revenues	$ 2,605	$ 2,748	$ 2,741
Operating expenses	(1,815)	(1,862)	(1,591)
Operating income	790	886	1,150
Other income	28	152	173
EBIT	$ 818	$ 1,038	$ 1,323
Throughput volumes (BBtu/d)[(1)]			
TGP	4,596	4,405	4,354
EPNG and MPC	4,065	4,535	4,310
ANR	3,691	3,776	3,807
CIG and WIC	2,644	2,341	2,106
SNG	2,020	1,877	2,132
Equity investments (our ownership share)	2,731	2,470	2,315
Total throughput	19,747	19,404	19,024

(1) Throughput volumes exclude those related to pipeline systems sold in connection with Federal Trade Commission orders related to our Coastal and Sonat mergers including the Midwestern Gas Transmission, East Tennessee Natural Gas and Sea Robin systems; and the Destin, Empire State and Iroquois pipeline investments. Throughput volumes exclude intrasegment activities.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Operating revenues for the year ended December 31, 2002, were $143 million lower than in 2001. The decrease was due to lower natural gas and liquids sales of $49 million resulting from lower prices in 2002 and $67 million due to the impact of lower natural gas prices in 2002 on net natural gas recovered and used in operations. Also contributing to the decrease were lower revenues of $49 million from natural gas sales and from gathering and processing activities due to the sale of CIG's Panhandle field in July 2002, lower transportation revenues of $49 million due to lower revenues from capacity sold under short-term contracts and lower throughput due to lower electric generation demand and milder winter weather in 2002. In addition, an $11 million decrease in operating revenues was due to the favorable resolution of regulatory issues related to natural gas purchase contracts in 2001, a $4 million decrease was due to lower rates on the Mojave pipeline system as a result of a rate case settlement effective October 2001, and a $6 million decrease due to the sale of our Midwestern Gas Transmission system in April 2001. These decreases were partially offset by $51 million of additional revenues due largely to transmission system expansion projects placed in service in 2001 and 2002, $13 million due to a larger portion of EPNG's capacity contracted at maximum tariff rates in 2002, $32 million from the Elba Island LNG facility placed in service in December 2001 and $18 million from the favorable resolution of measurement issues at a processing plant serving the TGP system in 2002.

Operating expenses for the year ended December 31, 2002, were $47 million lower than in 2001 primarily as a result of $41 million lower fuel and system supply purchases costs resulting from lower natural gas volumes and prices in 2002, $22 million from the impact of price changes in natural gas imbalances, $27 million due to lower employee benefit costs in 2002 due to cost efficiencies following the merger with Coastal, lower amortization of goodwill of $18 million due to the adoption of SFAS No. 142 in January 2002, $22 million decrease related to the sale of CIG's Panhandle field in July 2002 and $27 million from lower electricity, legal, environmental and overhead costs. Also contributing to lower operating expenses was $11 million due to a gain on the sale of pipeline expansion rights in February 2002. Offsetting these lower costs were charges of $7 million to our reserve for bad debts in 2002 related to the bankruptcy of Enron Corp., $10 million in contributions to a charitable foundation associated with EPNG's pipeline rupture, $13 million of higher amortization of additional acquisition costs assigned to a utility plant in 2002 and higher operating expenses of $16 million due to the Elba Island LNG facility returning to service in 2002. Also during 2002, we accrued $412 million for our Western Energy Settlement, and in 2001 we had merger-related costs of $291 million in connection with our Coastal merger. For a discussion of these charges, see Item 8, Financial Statements and Supplementary Data, Notes 2 and 4.

Other income for the year ended December 31, 2002, was $124 million lower than in 2001 primarily due to a $153 million asset impairment charge associated with our western Australia investment. Offsetting this charge was $11 million due to the resolution of uncertainties associated with the sales of our interests in the Empire State, Iroquois pipeline systems, and our Gulfstream pipeline project in 2001 offset by lower equity earnings of $6 million on Empire State and Iroquois pipeline systems due to the sale of our interests in 2001. Also offsetting the lower income were higher equity earnings in 2002 of $16 million primarily due to higher equity earnings from our investment in Great Lakes Gas Transmission.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Operating revenues for the year ended December 31, 2001, were $7 million higher than in 2000. The increase was due to higher reservation revenues of $67 million on the EPNG system as a result of a larger portion of its capacity sold at maximum tariff rates versus the same period in 2000 and the impact of completed system expansions and new storage and transportation contracts during 2001 on CIG of $33 million. Also contributing to the increase were the impact of higher natural gas prices in the first and second quarters on sales of segment-owned production of $29 million, sales of excess natural gas and sales under regulated natural gas sales contracts of $27 million, as well as higher throughput from increased deliveries to California and other western states of $6 million. These increases were partially offset by lower 2001 revenues of $44 million from contract remarketing in the TGP system in late 2000 and $42 million from the impact of the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and the East Tennessee Natural Gas and Sea Robin systems in the first quarter of 2000. Also partially offsetting the increase were lower 2001 sales of $22 million related to base gas from abandoned storage fields, the favorable resolution in 2000 of natural gas price-related contingencies on CIG of $28 million, $11 million from lower transportation revenues in 2001 on TGP as a result of higher proportion of throughput earnings from short versus long hauls compared to 2000 and $6 million from lower remarketed rates on seasonal turned-back capacity in 2001 as a result of SNG's 2000 rate case settlement allowing some customers to partially reduce their firm transportation capacity.

Operating expenses for the year ended December 31, 2001, were $271 million higher than in 2000 primarily as a result of the merger-related and other charges of $334 million in 2001 discussed previously. Also contributing to the increase was the impact of higher natural gas prices in the first half of 2001 on natural gas purchase contracts of $12 million, higher purchase gas costs of $8 million due to a natural gas imbalance revaluation in 2001 as a result of falling gas prices during the second half of the year, increases to our reserve for bad debts as a result of our exposure in connection with the bankruptcy of Enron Corp., and a one-time favorable adjustment to depreciation expense during the first quarter of 2000 of $10 million resulting from the FERC approval to reactivate the Elba Island LNG facility. Also contributing to the increase was the impact of gains in 2000 from the sales of non-pipeline assets of $8 million. Partially offsetting the increase were lower operating and maintenance expenses of $83 million due to cost efficiencies following the merger with Coastal and reduced operating and lower depreciation expenses of $19 million due to the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and East Tennessee and Sea Robin in the first quarter of 2000.

Other income for the year ended December 31, 2001, was $21 million lower than in 2000 due to lower equity earnings of $13 million on our Australian pipelines and Citrus Corp., which owns the Florida Gas Transmission System. Also contributing to the decrease was the impact on equity earnings due to the sales of our investments in the Empire State and Iroquois pipeline systems in 2001 of $8 million and the sale of our one-third interest in Destin Pipeline Company in 2000 of $2 million. Partially offsetting the decrease was increased earnings from our investment in the Alliance pipeline project of $9 million which commenced operations in the fourth quarter of 2000.

Production

The Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at the lowest total cost level possible.

Production has historically engaged in hedging activities on its natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on its sales. This is achieved primarily through natural gas and oil swaps. In the past, our stated goal was to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. As a component of our strategic repositioning plan in May 2002, we modified this hedging strategy. Under our modified strategy, we may hedge up to 50 percent of our anticipated production for a rolling 12-month forward period. This modification of our hedging strategy will increase our exposure to changes in commodity prices which could result in significant volatility in our reported results of operations, financial position and cash flows from period to period. As of December 31, 2002, we have hedged approximately 215 million MMBtu's of our anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $3.43 per MMBtu before regional price differentials and transportation costs.

During 2002, we continued an active onshore and offshore development drilling program to capitalize on our land and seismic holdings. This development drilling was done to take advantage of our large inventory of drilling prospects and to develop our proved undeveloped reserve base. We also completed asset dispositions in Colorado, Utah, western Canada and Texas as part of our balance sheet enhancement plan. Primarily due to our asset dispositions, we have a lower reserve base at January 1, 2003 than we did at January 1, 2002. See Item 8, Financial Statements and Supplementary Data, Note 28, for a discussion of our natural gas and oil reserves. Since our depletion rate is determined under the full cost method of accounting, a lower reserve base coupled with additional capital expenditures in the full cost pool will result in a higher depletion rate in future periods. For the first quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $1.59 per Mcfe.

We currently expect to reduce our total capital expenditures from approximately $2.4 billion in 2002 to approximately $1.4 billion in 2003. We continually evaluate our capital expenditure program and this estimate is subject to change based on market conditions. We will continue to pursue strategic acquisitions of production properties and the development of projects subject to acceptable returns. In July 2002, we acquired natural gas properties in the Raton Basin for approximately $140 million. These properties were acquired to expand our interest in the current coal seam project in the area.

Below are the operating results and analysis of these results for each of the three years ended December 31:

Production Segment Results	**2002**	**2001**	**2000**
	(In millions, except volumes and prices)		
Operating Revenues:			
Natural gas	$ 1,758	$ 2,005	$ 1,412
Oil, condensate and liquids	373	320	255
Other	(5)	22	19
Total operating revenues	2,126	2,347	1,686
Transportation and net product costs	(113)	(97)	(78)
Total operating margin	2,013	2,250	1,608
Operating expenses[1]	(1,484)	(1,331)	(995)
Operating income	529	919	613
Other income (loss)	5	1	(4)
EBIT	$ 534	$ 920	$ 609
Volumes and Prices:			
Natural gas			
Volumes (MMcf)	486,923	564,740	516,917
Average realized prices with hedges ($/Mcf)[2]	$ 3.61	$ 3.56	$ 2.73
Average realized prices without hedges ($/Mcf)[2]	$ 3.16	$ 4.23	$ 3.97
Average transportation costs ($/Mcf)	$ 0.18	$ 0.12	$ 0.11
Oil, condensate and liquids			
Volumes (MBbls)	17,514	14,382	11,626
Average realized prices with hedges ($/Bbl)[2]	$ 21.30	$ 22.24	$ 21.97
Average realized prices without hedges ($/Bbl)[2]	$ 21.39	$ 22.87	$ 28.39
Average transportation costs ($/Bbl)	$ 0.93	$ 0.56	$ 0.15

(1) Includes production costs, depletion, depreciation and amortization, ceiling test charges, merger-related costs, asset impairments, changes in accounting estimates, corporate overhead, general and administrative expenses and severance and other taxes.

(2) Prices are stated before transportation costs.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

For the year ended December 31, 2002 operating revenues were $221 million lower than in 2001. A 14 percent decrease in natural gas volumes and a 25 percent decrease in natural gas prices before hedges and transportation costs account for $848 million of the decrease in revenues, offset by a $599 million favorable variance from natural gas hedging activity in 2002 when compared to 2001. The decline in natural gas volumes is primarily attributable to the sale of properties in Colorado, Utah, and Texas. The decrease in operating revenues is partially offset by a 22 percent increase in oil, condensate and liquids volumes, net of a six percent decrease in their prices before hedges and transportation costs, resulting in a $46 million increase in revenues. In addition, oil hedging activity had a $7 million favorable variance in 2002 when compared to 2001. Further decreasing operating revenues was a loss of $13 million in 2002 resulting from a mark-to-market adjustment of derivative positions that no longer qualify as cash flow hedges. These hedges no longer qualify for hedge accounting treatment since they were designated as hedges of anticipated future production from natural gas and oil properties that were sold in March 2002.

Transportation and net product costs for the year ended December 31, 2002, were $16 million higher than in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees, offset by lower costs incurred to meet minimum payment obligations under pipeline agreements.

Operating expenses for the year ended December 31, 2002, were $153 million higher than in 2001. Contributing to the increase in expenses were non-cash full cost ceiling test charges totaling $269 million incurred in 2002 for our Canadian full cost pool and other international properties, primarily in Brazil, Turkey and Australia, offset by 2001 non-cash full cost ceiling test charges on international properties totaling $135 million. The unit of production depletion expense was higher by $93 million with $153 million due to higher depletion rates in 2002, offset by a $60 million decrease resulting from lower production volumes in 2002. The higher depletion rate resulted from higher capitalized costs in the full cost pool and a lower reserve base. Also contributing to the increase in 2002 expenses were increased oilfield service costs of $9 million due primarily to higher labor, workovers and production processing fees, asset impairments of $4 million and higher corporate overhead allocations of $34 million. Partially offsetting the increase in expenses were merger-related costs of $63 million incurred in 2001 relating to our combined production operations and $10 million for write-downs of materials and supplies recognized in 2001 resulting from the reduction in inventory values due to the implementation of consistent operating standards, strategies and plans following the Coastal merger. For a discussion of these merger-related costs and changes in accounting estimates, see Item 8, Financial Statements and Supplementary Data, Notes 4 and 6. In addition, the increase in expenses was offset by $49 million of lower severance and other taxes in 2002. The severance taxes decreased primarily because of lower natural gas volumes and prices, and for tax credits taken in 2002 for qualified natural gas wells.

Other income for the year ended December 31, 2002, was $4 million higher than in 2001 primarily due to higher earnings in 2002 from Pescada, an equity investment in Brazil.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Operating revenues for the year ended December 31, 2001, were $661 million higher than in 2000. A nine percent increase in natural gas volumes and a six percent increase in natural gas prices before hedges and transportation costs, account for $335 million of the increase in revenues. In addition, natural gas hedging activity had a $261 million favorable impact in 2001 when compared to 2000. A 19 percent decrease in oil, condensate and liquids prices before hedges and transportation costs, net of a 24 percent increase in oil, condensate and liquids volumes, decreased revenues by $1 million. This decrease was offset by a $66 million favorable impact from oil hedging activities in 2001 versus 2000.

Transportation and net product costs for the year ended December 31, 2001, were $19 million higher than in 2000 primarily due to a higher percentage of gas volumes subject to transportation fees and costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the year ended December 31, 2001, were $336 million higher than in 2000. Contributing to the increase were full cost ceiling test charges of $135 million on international properties, higher depletion expense of $80 million, with $64 million resulting from increased production and $16 million from higher depletion rates due to higher capitalized costs in the cost pool. Also contributing to the higher expenses in 2001 were merger-related costs of $63 million related to our combined production operations and $10 million for write downs of materials and supplies resulting from the reduction in inventory values due to the implementation of consistent operating standards, strategies and plans following the Coastal merger. Also increasing expenses in 2001 were higher oilfield service costs of $8 million and higher severance and other production taxes of $40 million, resulting from higher production volumes and higher natural gas prices.

Field Services

Assets in our Field Services segment primarily consist of our investment in El Paso Energy Partners and gathering and processing facilities in the south Texas, Louisiana, Mid-Continent and Rocky Mountain regions.

As the general partner of El Paso Energy Partners, we manage the partnership's day-to-day operations. In addition, we own through various subsidiaries 26.5 percent of the partnership's common units, all of the Series B preference units and all of the Series C units acquired for $350 million in November 2002. We recognize earnings and receive cash from the partnership in several ways, including through a share of the partnership's cash distributions and through our ownership of limited, preferred and general partner interests.

We are also reimbursed for costs we incur to provide various operational and administrative services to the partnership. In addition, we are reimbursed for other costs paid directly by us on the partnership's behalf. During 2002, we were reimbursed approximately $59 million for expenses incurred on behalf of the partnership. At December 31, 2002, our common units had a market value of $325 million, our preference units had a liquidation value of $158 million, and our Series C units had a value of $351 million. During 2002, our earnings and cash from El Paso Energy Partners were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner's share of distributions	$ 42	$ 43
Proportionate share of income available to common unit holders	10	30
Series B preference units	15	—(1)
Series C units	2	—(2)
	$ 69	$ 73

(1) The partnership is not obligated to pay distributions on these units until 2010.

(2) We received our first cash distributions in February 2003 for the Series C units since we acquired these units in November 2002.

During 2000 through 2002, we entered into several asset sales transactions with El Paso Energy Partners. Specific procedures have been instituted for evaluating these transactions to ensure that they are in the best interests of us and the partnership and are based on fair values. These procedures require our Board of Directors to evaluate and approve, as appropriate, transactions with the partnership. In addition, a special committee comprised of the general partner's independent directors evaluates the transactions on the partnership's behalf. This typically involves engaging an independent financial advisor to assist with the evaluation and to opine on its fairness.

In 2000, we sold an intrastate pipeline system in Alabama and storage facilities in Mississippi for $197 million, which included $170 million of Series B preference units issued to us in exchange for the storage facilities.

During 2001, we also sold several assets to the partnership, including NGL transportation and fractionation assets we acquired from PG&E and an investment in Deepwater Holdings, an entity that owned several pipeline gathering systems in the Gulf of Mexico. During 2001, the partnership also acquired rights to the Chaco processing facility from its previous owners, and we leased this facility under an agreement that expired in December 2002.

In 2002, as part of our plan to strengthen our capital structure and enhance our liquidity, we entered into additional transactions to sell various midstream assets to El Paso Energy Partners. In April 2002, we sold gathering and processing assets, including the intrastate natural gas pipeline system we acquired in our acquisition of PG&E's midstream operations in December 2000. We also sold substantially all our natural gas gathering, processing and treating assets in the San Juan Basin in November 2002. One of the San Juan Basin assets included in this transaction was our remaining interests in the Chaco cryogenic natural gas processing plant. As part of this transaction, we have an agreement that requires us to repurchase the Chaco processing plant from El Paso Energy Partners for $77 million in October 2021, and at that time, El Paso Energy Partners has the right to lease the plant from us for a period of ten years with the option to renew the lease annually thereafter. In addition to $416 million of cash, we received approximately 11 million Series C units valued at $350 million. The Series C units represent a new class of the partnership's limited partner interests and have no voting rights. Including the Series C units, our limited partner ownership interest in El Paso Energy Partners has increased to approximately 41 percent. For a discussion of our other transactions with El Paso Energy Partners, see Item 8, Financial Statements and Supplementary Data, Note 26.

In 2002, we also identified midstream assets to be sold to third parties as part of our plan to strengthen our capital structure and enhance our liquidity. We have also received interest from a number of parties interested in merging with and/or purchasing all or a portion of our general partner interest in El Paso Energy Partners. At this time, we cannot predict the outcome of these discussions.

In December 2002, we announced the sale of our gathering systems located in Wyoming to Western Gas Resources, Inc. This transaction was completed in January 2003. In March 2003, we received approval from our Board of Directors to sell our assets in the Mid-Continent and north Louisiana regions. Our Mid-Continent assets primarily include our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. Our north Louisiana assets primarily include our Dubach processing plant and Gulf States interstate natural gas transmission system. We expect this sale to close before the end of 2003. After this sale is completed, our remaining assets will consist primarily of processing facilities in the south Texas, Louisiana and Rocky Mountain regions. See Part II, Item 8, Financial Statements and Supplementary Data, Note 3 for a discussion of our other asset sales to third parties during 2002.

As a result of our asset sales and the resulting decline in our gathering and treating activities, we expect our future EBIT to decrease considerably. However, we expect the increase in earnings from our interests in El Paso Energy Partners to partially offset the anticipated decrease in EBIT.

We attempt to balance our earnings from our operating activities through a combination of fixed-fee based and market-based services. A majority of our gathering and transportation operations earn margins from fixed-fee-based services. However, some of our operations earn margins from market-based rates. Revenues from these market-based rate services are the product of the market price, usually related to the monthly natural gas price index and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, we may have more sensitivity to price changes during periods when natural gas and NGL prices are volatile.

We provide a variety of midstream services, including gathering and transportation of natural gas, and processing and fractionation of natural gas, NGL and natural gas derivative products, such as butane, ethane and propane.

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

Field Services Segment Results	**2002**	**2001**	**2000**
	(In millions, except volumes and prices)		
Gathering, transportation and processing gross margins	$ 349	$ 561	$ 437
Operating expenses	(78)	(437)	(271)
Operating income	271	124	166
Other income	16	71	48
EBIT	$ 287	$ 195	$ 214
Volumes and prices			
Gathering and transportation			
Volumes (BBtu/d)	3,023	6,109	3,868
Prices ($/MMBtu)	$ 0.17	$ 0.14	$ 0.16
Processing			
Volumes (inlet BBtu/d)	3,920	4,360	2,930
Prices ($/MMBtu)	$ 0.10	$ 0.15	$ 0.18

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Total gross margins for the year December 31, 2002, were $212 million lower than in 2001. Margins decreased by approximately $134 million due to our sales of midstream assets to El Paso Energy Partners in April 2002 and November 2002. In addition, processing margins decreased $58 million due to lower NGL prices in 2002, which primarily impacted our margins and volumes in the San Juan Basin, south Louisiana, south Texas and Rocky Mountain regions. Higher processing costs associated with a new processing arrangement at the Chaco processing facility entered into in the fourth quarter of 2001 with El Paso Energy Partners and the sale of the Dragon Trail processing plant in May 2002 also reduced our processing margins by $18 million and $6 million. This processing agreement with El Paso Energy Partners was terminated in November 2002 in connection with El Paso Energy Partners' acquisition of our San Juan Basin assets. Lower natural gas prices in the San Juan Basin in 2002 also resulted in a $22 million decrease in our gathering and treating margins. Partially offsetting these decreases were favorable resolutions of fuel, rate and volume matters of $13 million in the first quarter of 2002, $8 million of unfavorable resolutions of fuel matters which occurred in 2001 and $14 million due to higher realized transportation rates and increased system efficiency related to the pipeline system acquired in our acquisition of PG&E's midstream operation in December 2000. This pipeline system was one of the assets sold to El Paso Energy Partners in April 2002.

Operating expenses for the year ended December 31, 2002, were $359 million lower than in 2001. This decrease was primarily due to the sales of our San Juan Basin assets, our Natural Buttes and Ouray gathering systems and our Dragon Trail processing plant, resulting in a net gain of $245 million, lower operating costs of $48 million and lower depreciation expense of $35 million. Also contributing to the decrease was $46 million of merger-related costs in 2001, which included payments to El Paso Energy Partners related to Federal Trade Commission ordered sales of assets owned by the partnership, and a $9 million increase in our estimated environmental remediation liabilities in 2001. In addition, our 2002 cost reduction plan contributed $17 million to our lower operating costs. Our depreciation expense was also lower by $9 million due to the assets held for sale classification of the San Juan Basin assets in 2002 and $9 million associated with lower amortization of goodwill due to the adoption of SFAS No. 142 in January 2002 (see Item 8, Financial Statements and Supplementary Data, Note 1). Partially offsetting these decreases was an impairment charge of our north Louisiana facilities in the fourth quarter of 2002 of $66 million. We believe that these facilities are likely to be sold before the end of their estimated useful lives. For a further discussion of the asset sales and merger-related costs, see Item 8, Financial Statements and Supplementary Data, Notes 3 and 4.

Other income for the year ended December 31, 2002, was $55 million lower than in 2001. The decrease was due to the losses on the sale in 2002 of our investment in the Aux Sable NGL plant and our investment in the Blacks Fork natural gas processing plant of $47 million and $3 million. Also contributing to the decrease in other income for 2002 was a $13 million gain on the sale of our investment in Deepwater Holdings in October 2001, a gain of $8 million recorded in May 2001 from the sale of our 1.01 percent non-managing interest in El Paso Energy Partners and $6 million of lower equity earnings from Deepwater Holdings as a result of the sale of our interest to El Paso Energy Partners in October 2001. Offsetting these decreases were higher earnings of $22 million in 2002 from our interests in El Paso Energy Partners.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Total gross margins for the year ended December 31, 2001, was $124 million higher than in 2000. An increase of $133 million was due to higher gathering and processing volumes following our acquisition of PG&E's Texas Midstream operations in December 2000. Higher volumes also increased our margin by $14 million as a result of our acquisition of the Indian Basin processing plant in the second quarter of 2000 combined with an increase in Indian Basin's treating capacity by 23 percent in 2001. The increase in margin was partially offset by higher processing costs of $5 million associated with the new processing arrangement with El Paso Energy Partners at the Chaco processing facility in the fourth quarter of 2001. For the year ended December 31, 2001, lower average gathering, treating and processing rates resulted in a reduction in total margins of $17 million compared to 2000 due primarily to the different mix of assets and contract terms resulting from the acquisition of PG&E's Texas Midstream operations.

Operating expenses for the year ended December 31, 2001, were $166 million higher than in 2000. The increase was due to higher operating, depreciation and other expenses of $117 million primarily resulting from the acquisition of PG&E's Texas Midstream operations, as well as merger-related costs and other charges of $45 million. For a discussion of merger-related costs, see Item 8, Financial Statements and Supplementary Data, Note 4.

Other income for the year ended December 31, 2001, was $23 million higher than in 2000. The increase was primarily due to increased earnings from El Paso Energy Partners of $27 million and $13 million from a gain on the sale of our interest in Deepwater Holdings in October 2001, partially offset by lower 2001 equity earnings from Deepwater Holdings of $3 million as a result of the sale. The increase was also partially offset by equity investment losses of $7 million from our Mobile Bay and Aux Sable liquids processing facilities due to lower natural gas liquids prices and a decrease in equity earnings in other projects of $8 million.

Merchant Energy

Our Merchant Energy segment consists of three primary divisions: global power, petroleum and energy trading. In May 2002, we announced plans to limit our energy trading and mitigate our exposure to working capital demands. Our credit downgrades in the third and fourth quarter and a further deterioration of the energy trading environment led to our decision in November 2002 to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. We anticipate this liquidation may occur through 2004. Our liquidation strategy is intended to maximize cash flow from the trading portfolio and reduce our cash liquidity risk in an uncertain environment. Early in 2003, we also announced our intent to reduce our involvement in the LNG business and exit substantially all of our petroleum activities (excluding our Aruba refinery).

Below are Merchant Energy's operating results and an analysis of those results for each of the three years ended December 31:

Merchant Energy Segment Results	Division				Total Merchant Energy Segment
	Global Power	Petroleum	Energy Trading	Eliminations	
			(In millions)		
2002					
Gross margin	$ 1,139	$ 687	$ (862)	$(49)	$ 915
Operating expenses	(716)	(906)	(678)	49	(2,251)
Operating income (loss)	423	(219)	(1,540)	—	(1,336)
Other income (expense)	(429)	112	15	—	(302)
EBIT	$ (6)	$ (107)	$(1,525)	$ —	$(1,638)
2001					
Gross margin	$ 421	$ 894	$ 604	$ —	$ 1,919
Operating expenses	(329)	(1,055)	(137)	—	(1,521)
Operating income (loss)	92	(161)	467	—	398
Other income	369	111	26	—	506
EBIT	$ 461	$ (50)	$ 493	$ —	$ 904
2000					
Gross margin	$ 367	$ 895	$ 441	$ —	$ 1,703
Operating expenses	(271)	(796)	(64)	—	(1,131)
Operating income	96	99	377	—	572
Other income	298	39	21	—	358
EBIT	$ 394	$ 138	$ 398	$ —	$ 930

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities. In most cases, we partially own our power generating facilities and account for them using the equity method. We conduct most of our domestic power business through Chaparral. Internationally, we have invested in the Brazil power market through our equity investment in Gemstone. For a further discussion of our Chaparral and Gemstone investments, see *Off-Balance Sheet Arrangements and Contractual Obligations* above and Item 8, Financial Statements and Supplementary Data, Note 26. We also have interests in a number of other power facilities in Asia, Central America and Europe.

Power Contract Restructuring Activities. Many of our domestic power plants, and the power plants owned by Chaparral, have long-term power sales contracts with regulated utilities that were entered into under PURPA. The power sold to the utility under these PURPA contracts is required to be delivered from a specified power generation plant at power prices that are usually significantly higher than the cost of power in the wholesale power market. Our cost of generating power at these PURPA power plants is typically higher than the cost we would incur by obtaining the power in the wholesale power market, principally because the PURPA power plants are less efficient than newer power generation facilities.

In the past, we have been successful at renegotiating or restructuring these long-term power contracts. Typically, in a power contract restructuring, the PURPA power sales contract is amended so that the power sold to the utility does not have to be provided from the specific power plant. Because we have been able to buy lower cost power in the wholesale power market, we had the ability to reduce the cost paid by the utility, thereby inducing the utility to enter into the power contract restructuring transaction. Following a contract restructuring, the power plant operates on a merchant basis, which means that it is no longer dedicated to one buyer and will operate only when power prices are high enough to make operations economical. In addition, we may assume, and in the case of Eagle Point Cogeneration we did assume, the business and economic risks of supplying power to the utility to satisfy the delivery requirements under the restructured power contract over its term. When we assume this risk, we manage these obligations by entering into transactions to buy power from third parties that mitigate our risk over the life of the contract. These activities are reflected as part of our trading activities and reduce our exposure to changes in power prices from period to period. Power contract restructurings generally result in a higher rate of return on our investment in our power generation business because we can deliver reliable power at lower prices than our cost to generate power at these PURPA power plants. In addition, we can use the restructured contracts as collateral to obtain financing at a cost that is comparable to, or lower than, our existing financing costs.

During the last three years, we have successfully completed the restructuring of a number of long-term power contracts held by unconsolidated affiliates or, in some cases, held by us. As a result of our credit downgrades, our decision to exit the energy trading business, and disruption in the capital markets, it is unlikely we will pursue additional power contract restructurings in the near term. For a further discussion of these activities, see Item 8, Financial Statements and Supplementary Data, Note 13.

Global Power Division Results	2002	2001	2000
		(In millions)	
Gross margin	$ 1,139	$ 421	$ 367
Operating expenses	(716)	(329)	(271)
Operating income	423	92	96
Other income (expense)	(429)	369	298
EBIT	$ (6)	$ 461	$ 394

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Gross margin consists of revenues from our power plants and the net results from our power restructuring activities. The cost of fuel used in the power generation process is included in operating expenses. For the year ended December 31, 2002, gross margin for the global power division was $718 million higher than in 2001. Gross margin from power contract restructurings comprised $628 million of the increase. During 2002, we completed power contract restructurings or contract terminations at our Eagle Point Cogeneration, Mount Carmel and Nejapa power plants. The Eagle Point restructuring transaction, completed in March 2002, was our most significant power contract restructuring transaction and contributed $476 million to our net 2002 results.

The Eagle Point restructuring involved several steps and all revenues, expenses, fees and impairments were reported in our 2002 gross margin. First, we amended the existing PURPA power sales contract with Public Service Electric and Gas (PSEG) to eliminate the requirement that power be delivered specifically from the Eagle Point power plant. This amended contract has fixed prices with stated increases over the 14-year term that range from $85 per MWh to $126 per MWh. We entered into the amended power sales contract through a consolidated subsidiary, UCF. UCF was created to hold and execute the restructured power sales contract, to enter into a supply contract to meet the requirements of the restructured agreement and to monetize the net cash flows of these contracts by issuing debt. In keeping with its purpose, UCF entered into a power supply agreement with our energy trading division (EPME) who usually participates in our power restructuring activities by taking on the obligation to supply power. The terms of the EPME power supply contract were identical to the amended power sales contract, with the exception of price, which was set at $37 per MWh over its 14-year term.

For credit enhancement purposes, in anticipation of the financing transaction associated with the restructuring, UCF terminated the EPME supply contract in the second quarter of 2002 and replaced it with a supply contract with a Morgan Stanley affiliate. UCF entered into the Morgan Stanley contract solely for the purpose of reducing the cost of debt UCF would issue. EPME continued to supply power for the restructured transaction by entering into a power supply agreement with the Morgan Stanley affiliate. As a result of the steps we have taken in this transaction, we have replaced the high-cost of the power generated from the Eagle Point plant, which had averaged over $75 per MWh, with power that we purchased in the open market at an average cost of $31 per MWh. We have also shifted the collection and credit risks to third parties over the term of the restructured power sales agreement. The estimated improvement in margins associated with this restructuring is approximately $136 million over the life of the contracts.

The actions taken to restructure the contract required us to mark the contract to its fair value. As a result, we recorded non-cash revenue representing the estimated fair value of the derivative contract of approximately $978 million. We also amended or terminated other ancillary agreements associated with the cogeneration facility, such as gas supply and transportation agreements, a steam contract and existing financing agreements. We also paid $103 million to the utility to terminate the original PURPA contract. Also included in our operating results for 2002 were a $98 million non-cash charge to adjust the Eagle Point Cogeneration plant to fair value based on its new status as a peaking merchant plant and a non-cash charge of $230 million to write off the book value of the original PURPA contract. The transaction included closing and other costs of $21 million and the minority interest owner's share of this transaction of $50 million. Total operating cash flows from this transaction amounted to approximately $124 million of cash paid to the utility to amend the original contract and other costs and total financing cash flows included $829 million of proceeds from the issuance of 7.944% senior notes collateralized solely by the contracts and cash flows of UCF.

The other two power restructuring transactions during 2002 were the Nejapa and the Mount Carmel transactions. In 2002, an arbitration award panel approved the termination of the power purchase agreement between Comision Ejecutiva Hydroelectrica del Rio Lempa and the Nejapa Power Company, one of our consolidated subsidiaries, in exchange for a cash payment of $90 million. We recorded, as gross margin, a $90 million gain and also recorded $13 million in other expense for the minority owner's share of this gain. We applied the proceeds of the award to retire a portion of Nejapa's debt. The Mount Carmel restructuring involved the termination of the existing PURPA power purchase contract for a fee from the utility of $50 million. In addition, we recorded a non-cash adjustment to reflect fair value of the Mount Carmel facility of $25 million, resulting in a total net benefit on the restructuring transaction of $25 million.

Due to increasing market power prices in 2002, the net increase in gross margin from power contract restructurings of $628 million from our initial power restructuring transactions was partially offset by a decrease in the fair value of our restructured power contracts and related power supply contracts of $114 million from the initial gains through December 31, 2002. In addition to the net increase in gross margin relating to restructuring activities discussed above, gross margin increases of $147 million were realized from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002, partially offset by decreased revenues from the sale of the ManChief facility in 2001 to Chaparral. Also contributing to the increase were higher management fees in 2002 of $42 million primarily from Chaparral. Partially offsetting these increases were increased losses in other investments of $22 million during 2002.

Operating expenses include the cost of fuel used in the power generation processes, asset impairments and other costs we incur in operating and maintaining our power plants. Operating expenses for the year ended December 31, 2002, were $387 million higher than in 2001 primarily as a result of asset impairments that were recorded in 2002. In 2002, we wrote down our capitalized turbine costs by $162 million as we reduced our capital expenditure plans related to future power development as a result of our liquidity concerns, and accordingly our ability and intent to use the turbines in international and domestic power development projects changed. These reduced capital expenditure plans also impacted our ability to fund future financial investments, resulting in a $44 million impairment of goodwill by EnCap and Enerplus, our investment management subsidiaries. Plant operation and maintenance expenses increased by $156 million primarily resulting from the consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002, and the expansion of our South America, Central America and Mexico operations in 2002.

Other income for the year ended December 31, 2002, was $798 million lower than in 2001 primarily due to higher write downs on our equity investments over those that were recorded in 2001. Due to weak economic conditions in Argentina in 2002, we recorded a $342 million impairment of our CAPSA/CAPEX equity investment and Costanera cost investment. Also in 2002, we recorded a writedown of our PPN equity investment in India of $41 million due to PPN's sole customer failing to pay for power generated by the plant and significant difficulties encountered with operating the plant, and a $17 million impairment of our Milford equity investment where construction problems and disputes with our contractors and lenders have further delayed completion of the plant. In addition, we recognized a $74 million writedown of our CE Generation equity investment in December 2002 resulting from the sale of the underlying power plants, which was completed in the first quarter of 2003. The 2002 write downs were partially offset by impairments of $74 million on our Fife and East Asia equity investments in 2001. Contributing to the overall decrease was a decrease in equity earnings from Chaparral of $136 million, from Enfield due to unexpected plant shutdowns of $22 million, and from projects consolidated in the fourth quarter of 2001 and first quarter of 2002 of $52 million. Other income also decreased by $51 million due to the minority owner's interest in income of projects consolidated by us in 2002, and a $22 million decrease in operating lease income as a result of the consolidation of Nejapa in 2002. Other income also decreased due to $75 million in fees earned for engineering, construction management and other services for the Macae power project during 2001 that did not recur in 2002 because the power plant became operational after it was contributed to Gemstone in late 2001. These decreases were partially offset by higher equity earnings of $107 million from Gemstone during 2002.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Gross margin for the year ended December 31, 2001, was $54 million higher than in 2000. This increase was primarily due to an increase of $67 million in management fees earned from Chaparral during 2001. Also contributing to the increase were higher margins of $55 million from a Philippine power project that was consolidated in the first quarter of 2001. Partially offsetting these increases was a decrease of $61 million in margins associated with our West Georgia facility, which we sold to Chaparral in the fourth quarter of 2000.

Operating expenses for the year ended December 31, 2001, were $58 million higher than in 2000. This increase was primarily due to an increase in plant operation and maintenance expenses of $100 million resulting from the consolidation of a Philippine power project in 2001 and expansion of our operations in Mexico and Brazil during 2001. In addition, we recorded $12 million in merger-related costs and other charges in 2001 associated with combining our operations with Coastal's operations. See Item 8, Financial Statements and Supplementary Data, Notes 4 and 5, for a discussion of these merger-related costs and asset impairments of our long-lived assets. These increases were partially offset by lower costs of $33 million at our West Georgia facility, which was sold in the fourth quarter of 2000.

Other income for the year ended December 31, 2001, was $71 million higher than in 2000. This increase was primarily due to $75 million of fees earned for engineering, construction management and other services related to the development of the Macae power project in Brazil in 2001. Also contributing to this increase was an increase in equity earnings from Chaparral of $80 million during 2001 and from other equity investments of $28 million during 2001. Partially offsetting these increases were an impairment of $74 million of our Fife and East Asia equity investments in 2001 and gains of $36 million from the sale of our interests in East Asia and Guatemalan power projects in 2000.

Petroleum

In addition to exiting our energy trading business, we announced in February 2003 our intent to reduce our involvement in the LNG business and exit substantially all of our petroleum businesses, except for our Aruba refinery. We currently own or have interests in oil refineries, chemical production facilities, petroleum terminalling and marketing operations, and blending and packaging operations for lubricants and automotive products. Our refinery operations are cyclical in nature and sensitive to movements in the price of crude oil. During the last two years, we have operated in an environment where the differences in the price of our crude oil input and the price we can realize for the resulting products output has been so narrow that we have experienced losses in our refinery operations. While the condition has improved during the first quarter of 2003, our results in the future may continue to be volatile. Also contributing to losses in 2002 and 2001 were operational difficulties following a fire at our Aruba facility in 2001.

Petroleum Division Results	**2002**	**2001**	**2000**
		(In millions)	
Gross margin	$ 687	$ 894	$ 895
Operating expenses	(906)	(1,055)	(796)
Operating income (loss)	(219)	(161)	99
Other income	112	111	39
EBIT	$(107)	$ (50)	$ 138

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Gross margin consists of revenues from our refineries and commodity trading activities, less costs of the feedstocks used in the refining process and the costs of commodities sold. For the year ended December 31, 2002, our gross margin was $207 million lower than in 2001. This decrease was primarily due to a $67 million decline in the fair value of our LNG supply contract derivatives in 2002 compared to a $86 million increase in the fair value of these contracts in 2001. Also contributing to this decrease was lower refining margins of $84 million resulting from lower throughput at our Aruba refinery. Also, we recorded $57 million of insurance claims and recoveries in 2001 related to our refinery losses associated primarily with a fire at our Aruba facility in April 2001, a decrease of $143 million in marine revenues resulting from lower marine freight rates and number of operating vessels and a decrease of $86 million associated with the lease of our Corpus Christi refinery and related assets to Valero in June 2001. These decreases were partially offset by increased refining margins of $74 million at our Eagle Point refinery and a gain of $210 million from the sale of a long-term LNG supply contract and capacity rights at a regasification terminal to Snøhvit during 2002.

Operating expenses for the year ended in December 31, 2002, were $149 million lower than in 2001. The decrease was primarily due to $244 million of merger-related costs, asset impairments and other charges in

2001 primarily associated with combining our operations with Coastal's operations. See Item 8, Financial Statements and Supplementary Data, Notes 4 and 5 for a discussion of our merger-related costs and asset impairments. This decrease was partially offset by a $91 million impairment of our MTBE chemical processing plant in 2002 and a $7 million increase in operating costs associated with the expansion of our LNG operations during 2002.

Other income for the year ended December 31, 2002, was $1 million higher than in 2001. The increase was primarily due to $46 million of insurance claims and recoveries from our insurers recorded in 2002 compared to $40 million, net of writeoffs of damaged properties in 2001, primarily associated with the assets destroyed in a fire at our Aruba facility in April 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

For the year ended December 31, 2001, our gross margin was $1 million lower than in 2000. The decreases from year to year were the result of a $105 million decrease in margins in crude based refined products and lower margins and throughput at the Eagle Point refinery as a result of decreased demand for jet fuel following the events of September 11, 2001. Also contributing to the decrease was a $48 million decrease in margins associated with the lease of our Corpus Christi refinery and related assets to Valero in June 2001. Partially offsetting these decreases was a $86 million increase in the fair value of our LNG supply contract derivatives during 2001 compared to a $54 million decrease in the fair value of these contracts in 2000, and $22 million of margins earned on Coastal Liquid Partners, which was consolidated during early 2001. Also offsetting these decreases were $57 million of insurance claims and recoveries from our insurers on losses incurred related primarily to a fire at our Aruba facility in April 2001. This fire was the primary reason for a 25 percent decrease in output between 2000 and 2001 resulting in a $53 million reduction, year over year, in refining margins.

Operating expenses for the year ended in December 31, 2001, were $259 million higher than in 2000. The increase was primarily due to $249 million of merger-related costs, asset impairments and other charges in 2001 associated with combining our operations with Coastal's operations. See Item 8, Financial Statements and Supplementary Data, Notes 4 and 5 for a discussion of our merger-related costs and asset impairments of our long-lived assets. Also contributing to this increase was a $26 million increase in operating expenses associated with our LNG business in 2001 and higher fuel costs of $29 million at our refineries due to higher natural gas prices. These increases were partially offset by lower operating expenses of $64 million resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001.

Other income for the year ended December 31, 2001, was $72 million higher than in 2000. The increase was primarily the result of $77 million of insurance claims and recoveries, net of writeoffs of damaged properties of $37 million, from our insurers associated primarily with the assets destroyed in the Aruba fire.

Energy Trading

Our energy trading activities have historically included actively managing the inherent risk across Merchant Energy's asset portfolios as well as providing customers with risk management solutions involving natural gas, power, crude oil, refined products, chemicals and coal. This division also conducted a substantial energy trading business that executed proprietary trading strategies and managed the segment's risk across multiple commodities and over seasonally fluctuating energy demands using consistent methodologies. In November 2002 we announced that we would exit the energy trading business due to the increasing and volatile cash demands inherent in that business, which were magnified by our credit downgrade. We are in the process of liquidating our trading price risk management portfolio and anticipate that this effort will continue through 2004.

Our liquidation strategy is being executed in a variety of ways including:

- negotiating early settlements pursuant to contractual terms with our counterparties;
- actively pursuing the sale of transactions or the entire portfolio to third parties;

- matching and transferring offsetting positions with different counterparties;
- transferring transactions to other El Paso segments or divisions; and
- liquidating through scheduled settlements.

In late 2002, we began actively liquidating our trading portfolio. As of December 31, 2002, we had approximately 40,000 transactions to be settled in the future. Included in our portfolio at that time was approximately 4.4 Bcf/d of natural gas transportation capacity and natural gas storage rights of approximately 125 Bcf. As of December 31, 2002, we had contracted to sell 2.1 Bcf/d of that transportation capacity and 70 Bcf of those gas storage rights. The sale resulted in a loss of approximately $25 million. Additionally, in the first quarter of 2003, we sold our European natural gas trading portfolio and completed the liquidations of all of our open trading positions in Europe. We incurred a loss of approximately $4 million on this sale and liquidation. We are continuing to work with numerous counterparties to liquidate the remainder of our portfolio through 2004.

Fair Value of Price Risk Management Contracts as of December 31, 2002

The following table details the net estimated fair value of our energy contracts (both trading and non-trading) by year of maturity and valuation methodology as of December 31, 2002. We classify as trading activities those price risk management activities that we enter into with the objective of generating profits or benefiting from exposure to shifts or changes in market prices. We classify all other derivative-related activities, including those related to power restructuring activities, as non-trading price risk management activities.

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Trading contracts						
Exchange-traded positions[1]	$ (16)	$ (80)	$ 3	$ 3	$ —	$(90)
Non-exchange traded positions[2]	42	77	(12)	(52)	(24)	31
Total trading contracts, net	26	(3)	(9)	(49)	(24)	(59)
Non-trading contracts[3]						
Non-exchange traded positions[2]	(148)	(35)	122	329	191	459
Total energy contracts	$(122)	$ (38)	$113	$280	$167	$400

(1) Exchange-traded positions include positions that are traded on active exchanges such as the New York Mercantile Exchange, International Petroleum Exchange and London Clearinghouse.

(2) Non-exchange traded positions include positions based on exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts.

(3) Non-trading energy contracts include derivatives from our power contract restructuring activities of $968 million and derivatives related to our natural gas and oil producing activities of $(509) million. Earnings related to the natural gas and oil producing activities are included in our Production segment results.

The energy trading industry experienced dramatic changes during 2002, especially in the fourth quarter. These changes included the credit downgrades of many of the major industry participants and actions taken by most of the major industry participants to reduce their trading activities or completely exit the business. Because of our own actions to limit our trading activities and exit the trading business, our accessibility to reliable forward market data for purposes of estimating fair value was significantly limited in late 2002. As a result, we obtained valuation assistance from a third party valuation specialist in determining the fair value of our trading and non-trading price risk management activities as of December 31, 2002. Based upon the specialist's input, our estimates of fair value are based upon price curves derived from actual prices observed in the market, pricing information supplied by the specialist and independent pricing sources and models that rely on this forward pricing information. These estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable time under present market conditions, modeling risk, credit risk of our counterparties and operational risks, as needed. We have discontinued applying our ten-year liquidity valuation allowance that we had instituted during the first quarter of 2002 in circumstances where there was uncertainty related to our forward prices in less liquid markets. To the extent that the forward market data received from the third party specialist indicates value beyond ten years, we now include that value in the fair value of our trading and non-trading price risk management activities.

The income impacts of both our trading and non-trading price risk management activities are included in all divisions of our Merchant Energy segment and our Production segment. A reconciliation of these trading and non-trading activities for the years ended December 31, 2002 and 2001, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2000	$ 2,200	$ —	$ 2,200
Cumulative effect of accounting change[1]	—	(1,921)	(1,921)
Fair value of contract settlements during the period	(1,973)	744	(1,229)
Initial recorded value of new contracts	160	—	160
Change in fair value of contracts[2]	680	1,636	2,316
Other[3]	228	—	228
Net change in contracts outstanding during the period	(905)	459	(446)
Fair value of contracts outstanding at December 31, 2001	1,295	459	1,754
Cumulative effect of accounting change	(343)	—	(343)
Inventory-related reclassifications as a result of accounting change	(254)	—	(254)
Fair value of contract settlements during the period	(185)	(274)	(459)
Initial recorded value of new contracts[4]	84	991	1,075
Change in fair value of contracts	(635)	(717)	(1,352)
Other[3]	(21)	—	(21)
Net change in contracts outstanding during the period	(1,354)	—	(1,354)
Fair value of contracts outstanding at December 31, 2002	$ (59)	$ 459	$ 400

(1) On January 1, 2001, we adopted SFAS No. 133 and recorded a cumulative effect of accounting change of $1,921 million related to our hedging price risk management activities.

(2) Includes a net loss of $109 million related to changes in the market values of contracts transferred to our trading portfolio as a result of a change in the manner in which these contracts were managed following the Coastal merger.

(3) Includes option premiums and storage capacity transactions.

(4) The initial recorded value of new contracts for trading primarily comes from completing our Snøhvit LNG supply contract in the second quarter of 2002 and for non-trading primarily comes from our Eagle Point Cogeneration restructuring transaction completed in the first quarter of 2002. See the discussion of these transactions under results of operations in our global power and petroleum divisions.

(5) As a result of the discontinuance of our ten-year liquidity valuation allowance, we have reversed $29 million which represents the remaining balance of our initial valuation allowance of $61 million.

Our trading price risk management assets and liabilities changed significantly in the fourth quarter of 2002 partly because we adopted EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* The adoption of EITF Issue No. 02-3 had the following impacts on our financial statements:

- We eliminated the mark-to-market value for contracts that do not meet the definition of a derivative, including transportation, storage and other contracts, which we reported as a cumulative effect of change in accounting principle of $225 million;

- We adjusted the carrying value of our natural gas inventory to its weighted average cost and the value of inventory exchanges to their expected settlement price assuming they had been accounted for under that basis since their acquisition, which we reported as a cumulative effect of change in accounting principle of $118 million; and

- We reclassified $254 million of our natural gas inventory and inventory exchanges from price risk management assets to inventory and accounts receivable and payable on our balance sheet.

Overall, the adoption of EITF Issue No. 02-3 reduced our net assets from price risk management activities by approximately $597 million, lowered our pre-tax net income by $343 million and lowered our net income by $222 million. Those contracts for which the mark-to-market value was eliminated are now accounted for under the accrual method of accounting.

The fair value of contract settlements during the period represents the amounts of traded contracts settled in cash, through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The initial recorded value of new contracts includes the fair value of origination transactions at the time the transaction is initiated.

The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination, until their settlement or, if not settled, until the end of the period. One of the most significant factors affecting the declines in fair value of our trading and non-trading price risk management activities was the decrease in option value, especially in longer-dated and complex transactions. Despite the commodity price volatility seen in the market over recent months, we are finding that the remaining market participants are ascribing very little option value to these types of transactions. Additionally, because of the significant reductions in the creditworthiness of many of our counterparties, we were required to adjust our valuation allowances. Because of these and other market changes, particularly those experienced in the fourth quarter, we recognized a loss in our petroleum and energy trading divisions due to changes in fair value of $635 million in 2002.

In accordance with generally accepted accounting principles, we have reflected our trading portfolio at estimated fair value, which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. However, the value we ultimately receive in settlement of our trading activities may be less than our estimates. As disclosed previously, we are actively liquidating our trading portfolio, which included approximately 40,000 transactions as of December 31, 2002. We believe the net realizable value of our trading portfolio may be less than their currently estimated fair value. Our belief is based on recent transactions completed at values below estimated fair value and bids received on transactions that were also below their fair value. Additionally, because of the adoption of EITF Issue No. 02-3, a portion of the transactions that we plan to liquidate are accounted for under the accrual method and are not recorded on our balance sheet. We believe that the amount we may ultimately realize from the liquidation of our total portfolio (including our accrual-based portfolio) could result in future losses of up to $200 million.

See Item 8, Financial Statements and Supplementary Data, Note 1 for our revenue recognition policy related to these activities. The operating results of our energy trading division are presented below:

Energy Trading Division Results	2002	2001	2000
		(In millions)	
Gross margin	$ (862)	$ 604	$ 441
Operating expenses	(678)	(137)	(64)
Operating income (loss)	(1,540)	467	377
Other income	15	26	21
EBIT	$(1,525)	$ 493	$ 398

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our energy trading portfolio. For the year ended December 31, 2002, gross margin was $1.5 billion lower than in 2001. The decrease was due to a combination of factors related to changes in the energy trading environment. Approximately $1.3 billion of this decrease relates to a general market decline in energy trading resulting from lower price volatility in the natural gas and power markets and a generally weaker trading and credit environment in 2002. Additionally, in the fourth quarter of 2002, many of the participants in the trading industry, including us, publicly announced their intent to discontinue or significantly reduce trading operations, which we believe, along with other factors caused a further deterioration of the market valuations of trading and marketing assets. The decrease in fair value of our trading and non-trading price risk management activities was largely related to reduced option value, with the remainder of the decrease resulting from the volatility of forward prices and reductions in creditworthiness of our counterparties. The decline in the energy trading environment caused us to reduce our trading and origination operations which resulted in a decrease of $135 million in the gains from transactions we originated in 2002 compared to 2001 primarily associated with transportation, storage and gas supply contracts.

Operating expenses for the year ended December 31, 2002, were $541 million higher than in 2001. This significant increase relates primarily to a charge of $487 million related to our Western Energy Settlement and a charge of $20 million related to our Commodities Futures Trading Commission (CFTC) settlement. See Item 8, Financial Statements and Supplementary Data, Note 2 for a description of our Western Energy Settlement and Item 8, Financial Statements and Supplementary Data, Note 20 for a description of our CFTC settlement. Adding to this increase were additional costs of $5 million to expand our London operations in early 2002 and an $18 million increase in staffing and infrastructure costs in 2002. During 2003, we liquidated our European trading assets and will close these offices.

Other income for the year ended December 31, 2002, was $11 million lower than in 2001 primarily due lower interest rates and lower average outstanding balances on our interest-bearing margin deposits and notes receivable during 2002.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

For the year ended December 31, 2001, gross margin was $163 million higher than in 2000. The increase was due to higher trading margins in natural gas and power as a result of increased trading volumes and price volatility, net of the reserves established as a result of the bankruptcy of Enron Corp. in December 2001.

Operating expenses for the year ended December 31, 2001, were $73 million higher than in 2000. The increase was partially the result of $27 million of merger-related asset impairments in 2001. The remaining increase of $46 million related to increased personnel costs to support increased origination activity and expansion of our European operations in 2001 compared to 2000.

Other income for the year ended December 31, 2001, was $5 million higher than in 2000. This increase was primarily due to a $16 million increase in other income resulting from higher interest rates and higher average outstanding balances on our interest-bearing margin deposits and notes receivable during 2001. These increases were offset by $11 million of equity earnings in 2000 no longer being recorded upon termination of the Engage joint venture in October 2000.

Corporate and Other Expenses, Net

Our Corporate and Other operations includes our general and administrative activities, as well as the operations of our telecommunications and other miscellaneous businesses. During 2001, there was a significant downturn in the telecommunications market. As a result, we refocused our telecommunications strategy and reduced our capital investment in this start-up business. Our current business strategy involves primarily the development of wholesale metropolitan transport services, primarily in Texas. At December 31, 2002, our net investment in the telecommunications business was $388 million, which includes $163 million of goodwill.

Our telecommunications business consists of Texas-based metro transport services and collocation and cross-connect services. Our Texas-based metro transport services business provides bandwidth transport services to wholesale customers in Austin, San Antonio, Dallas, Ft. Worth and Houston. There are several new initiatives aimed at expanding our market share within existing markets. In 2003, we are expanding our business model to include commercial customers through the launch of our channel partners program, which utilizes third party entities as outside sales representatives in order to market our existing products to commercial customers. We will also offer to both wholesale and commercial customers additional products designed specifically to leverage our existing asset infrastructure, including gigabit ethernet. We provide a cost-effective service because of our ability to use parts of the telecommunications infrastructure of SBC under our interconnection agreement with them. We are currently involved in proceedings with SBC that could impact our cost of using their infrastructure, and possibly our ability to use this infrastructure in the future. For an additional discussion of this proceeding, see Item 8, Financial Statements and Supplementary Data, Note 20 under the subheading *Southwestern Bell Proceeding*. Because of the continuing decline in the telecommunications industry, we evaluate the fair value of our Texas-based assets, including our goodwill of $163 million, each quarter to determine if they are impaired. As of December 31, 2002, these assets were not impaired. We did, however, write off $15 million of right-of-way assets, primarily in the Northeast, due to decisions not to construct along these rights-of-way or expand the business into these market areas. There are a number of factors that could impact the valuation of our Texas-based metro transport business in the future, including a negative outcome of our SBC proceeding, judicial or legislative changes affecting the current regulatory framework, a decline in our forecasted demand for services in the areas we serve or a further decline in the telecommunications industry impacting our ability to expand this business.

In December 2002, we decided to exit our long-haul and metro dark fiber business because of the minimal contribution of the activities and the high cost of maintaining it. Under these circumstances, the value of our inventory is impaired and, accordingly, in the fourth quarter we reduced the carrying value of our inventory by $153 million to $5 million. This is in addition to a third quarter reduction of $8 million. The market value was determined by an independent appraiser who evaluated the dark fiber value based on market conditions existing in the fourth quarter of 2002 and recent liquidation values for dark fiber. Our remaining $4 million of value is attributable to our route from Houston, Texas to Los Angeles, California, which is the center of an arbitration proceeding between us and Broadwing Communications Services. For a further discussion of this matter, see Item 8, Financial Statements and Supplementary Data, Note 20.

Our collocation and cross-connect services are available through our Lakeside Technology Center, a Chicago-based telecommunications facility that provides space for telecommunications carriers designed for their unique equipment needs, as well as access to multiple network connections of various telecommunications carriers. We operate this facility under an operating lease that has a residual value guarantee of $237 million. In the second quarter of 2002, we reached a final settlement of a lease agreement at the facility with Exodus Communications, Inc., who has now filed for bankruptcy. Although we received some consideration, the settlement resulted in the termination of the lease and the loss of a significant tenant at the facility. The building design, which is beneficial for the heavy equipment, low staffing needs of a telecommunications provider, also limits the alternative uses for the facility putting pressure on the fair value of the building during this significant downturn in the telecommunications industry. Consequently, we analyzed the fair value of the building. Our analysis was completed in the third quarter of 2002, and we estimated that the fair value of the building was $162 million, which is significantly below the expected residual value originally anticipated and guaranteed under our lease agreement and results in a contingent loss of $113 million. Consequently, we are amortizing this deficiency over the remaining lease term. This resulted in a charge of $11 million in 2002, and will result in a charge of $8 million for each remaining quarter through May 2006. Upon the adoption of the new accounting pronouncement, Financial Accounting Standards Board Interpretation (FIN) No. 46, in July 2003, we anticipate that we will consolidate the lessor of this facility which will likely require an adjustment to the fair value of the facility (see New Accounting Pronouncements Issued But Not Yet Adopted below).

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Corporate and other net expenses for the year ended December 31, 2002, were $1,202 million lower than in 2001. The decrease was primarily a result of $1,175 million in merger-related charges and asset impairments incurred in 2001, in connection with our merger with Coastal and additional costs of $144 million incurred in 2001 related to increased estimates of environmental remediation costs, legal obligations and reductions in the fair value of spare parts inventories to reflect changes in usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the Coastal merger. For a discussion of these costs, see Item 8, Financial Statements and Supplementary Data, Notes 4 and 6. Also contributing to the decrease was a reduction in telecommunication expenses of $25 million in 2002 due to our 2001 telecommunication organizational restructuring and losses of $34 million in 2001 on our retail gas stations, substantially all of which were sold in 2001. In addition, in 2002, we recorded a $21 million gain on the early extinguishment of debt. Partially offsetting the decrease for the year ended December 31, 2002, were charges of $50 million for severance payments related to our second quarter 2002 employee restructuring, costs associated with the elimination of rating and stock-price triggers in the second quarter of 2002 in our Gemstone and Chaparral investments and a $21 million decrease in pre-tax pension income as a result of a reduced expected rate of return on our pension plan assets. In addition, in our telecommunication operations, in 2002, we recorded a $153 million valuation adjustment of our dark fiber inventory, a $15 million impairment of our right-of-way assets and a $11 million contingent loss on the Lakeside Technology Center facility, as discussed above.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Corporate and Other expenses for the year ended December 31, 2001, were $1,372 million higher than in 2000. The increase was primarily a result of additional $1,082 million incurred in 2001 compared to 2000 of merger-related costs and asset impairments incurred in 2001 in connection with our mergers with Coastal and Sonat and additional costs of $144 million incurred in 2001 related to increased estimates of environmental remediation costs, legal obligations and usability of spare parts inventories and $39 million in lower margins due to the sale of substantially all of our retail gas stations in 2001. Also contributing to our higher costs were operating losses associated with our telecommunications business during 2001 which were approximately $40 million.

Interest and Debt Expense

Over the past three years, our interest and debt expense has increased as a result of debt issued to finance the growth of our business segments. During this period, our average debt balances have increased from approximately $10.8 billion in 2000 to $16 billion as of December 31, 2002. During this growth period, we have raised funds in both domestic and international capital markets, the majority of which was fixed rate debt. In the future, our ability to access the capital markets and issue debt securities will be a function of market conditions at that time and our credit ratings. Based on rating actions during the latter part of 2002 and early 2003, we anticipate that the cost of future debt issuances will be higher for us. Furthermore, since some of our debt offerings have been in foreign markets, currency fluctuations can impact that cost of our debt. For example, in 2002, as a result of a weaker U.S. dollar, we incurred incremental interest costs of approximately $95 million on our Euro denominated debt.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Interest and debt expense for the year ended December 31, 2002, was $244 million higher than in 2001. Below is an analysis of our interest expense during the year ended December 31 (in millions):

	2002	2001	2000
Long term debt, including current maturities	$1,249	$ 952	$ 891
Commercial paper	42	98	90
Other interest	142	171	141
Less: Capitalized interest	(33)	(65)	(82)
Total interest expense	$1,400	$1,156	$1,040

Interest expense on long-term debt for the year ended December 31, 2002, was $297 million higher than in 2001. The increase was due to a higher average debt balance. During 2002, we issued long-term debt of approximately $4.4 billion that had an average interest rate of 7.9%. These issuances increased interest on long-term debt by approximately $233 million. During the same year, we retired approximately $1.6 billion of long-term debt that had an average interest rate of 5.1%, resulting in a decrease to interest expense from these retirements of approximately $36 million. In addition, we incurred $95 million of interest expense in 2002 related to foreign currency losses on Euro-denominated debt that was unhedged in 2002. The remaining increase was primarily due to various debt issuances during 2001 that were outstanding for the entire year in 2002.

Interest expense on commercial paper for the year ended December 31, 2002, was $56 million lower than in 2001. The decrease was due to lower average short-term interest rates on commercial paper activities and lower average short-term borrowings in 2002. The average short-term interest rate, which is based on daily ending rates, was 2.7% in 2002 versus 4.6% in 2001, and the average commercial paper and other short-term debt balances, which were based on daily ending balances, were approximately $963 million in 2002 versus $1.45 billion in 2001.

Other interest for the year ended December 31, 2002, was $29 million lower than in 2001. The decrease was primarily due to a $23 million decrease in interest resulting from retirement of our other financing obligations, an $8 million decrease in interest of receivable factoring, and an $8 million decrease in interest due to termination of a marketing sales contract during 2002. These decreases were partially offset by a $9 million increase in interest from the debt securities issued to Gemstone in November 2001.

Capitalized interest for the year ended December 31, 2002, was $32 million lower than in 2001 primarily due to the lower interest rates in 2002 than in 2001.

We expect to incur higher interest and debt expense on debt issuances in 2003 due to our credit downgrades below investment grade status.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Interest and debt expense for the year ended December 31, 2001, was $116 million higher than in 2000.

Interest expense on long-term debt for the year ended December 31, 2001, was $61 million higher than in 2000. The increase was due to higher average debt balance. During 2001, we issued long-term debt of approximately $4.1 billion that had an average interest rate of 6.1%. These issuances increased interest on long-term debt by approximately $125 million. During the same year, we retired approximately $1.6 billion of long-term debt that had an average interest rate of 6.8%, resulting in a decrease to interest expense from these retirements of approximately $68 million. The remaining increase was primarily due to fourth quarter 2000 debt issuances that were outstanding for the entire year in 2001.

Interest expense on commercial paper for the year ended December 31, 2001, was $8 million higher than in 2000. The increase was due to the higher average commercial paper balances. Average commercial paper and other short-term debt balances, which were based on daily ending balances, were approximately $1.45 billion in 2001. This increase was offset by lower average rates on commercial paper and other short-term borrowings during the year. The average interest rate, which is based on daily ending rates, was 4.6% in 2001.

Other interest for the year ended December 31, 2001, was $30 million higher than in 2000. The increase was primarily due to $9 million of interest expense associated with a swap agreement and $11 million of interest expense associated with other financing obligations.

Capitalized interest for the year ended December 31, 2001, was $17 million lower than in 2000 due to the completion of the West Georgia facility during the middle of 2000.

Minority Interest in Consolidated Subsidiaries

Expense associated with minority interests of consolidated subsidiaries for the year ended December 31, 2002, was $56 million higher than in 2001. This increase was primarily due to 2002 income of the minority owners of Eagle Point Cogeneration, Utility Contract Funding, CDECCA and Mohawk River Funding IV as a result of our consolidation of these companies during 2002. These consolidations contributed $38 million of the 2002 increase. An additional $13 million of the increase related to the minority owner's share of the gain from the termination of the Nejapa power purchase agreement.

Returns on Preferred Interests of Consolidated Subsidiaries

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Returns on preferred interests of consolidated subsidiaries for the year ended December 31, 2002, were $58 million lower than in 2001, primarily due to the redemptions of the preferred interests related to El Paso Oil & Gas Resources, El Paso Oil & Gas Associates, Coastal Limited Ventures and Capital Trust IV and the partial redemption of Clydesdale. The decrease was also due to lower interest rates in 2002. Most of the preferred returns are based on variable short-term rates, which were lower on average in 2002 than the same periods in 2001. Partially offsetting these decreases were higher returns on preferred interests issued as part of our Gemstone investment completed in November 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Returns on preferred interests of consolidated subsidiaries for the year ended December 31, 2001, were $13 million higher than in 2000. Higher balances in minority interests as a result of the issuance of additional preferred interests in Clydesdale and Topaz (part of our Gemstone transaction) in 2001 and a full year of costs on Clydesdale and Capital Trust IV, were significantly offset by lower interest rates. Clydesdale and Capital Trust IV were formed in May 2000.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Item 8, Financial Statements and Supplementary Data, Note 19.

Income Tax Expense

Income tax benefit for the year ended December 31, 2002, was $495 million resulting in an effective tax rate of 28 percent. For the year ended December 31, 2001, income tax expense was $184 million, resulting in an effective tax rate of 72 percent. Of this amount, $115 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges was 27 percent in 2001. For the year ended December 31, 2000, income tax expense was $539 million, resulting in an effective tax rate of 30 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent in all years were primarily a result of the following factors:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends;
- non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;
- foreign income taxed at different rates;
- utilization of deferred credits on loss carryovers;
- non-deductible dividends on the preferred stock of a subsidiary;
- non-conventional fuel tax credits; and
- depreciation, depletion and amortization.

For a reconciliation of the statutory rate of 35 percent to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 9.

Contingencies

For a discussion of our contingencies, see Item 8, Financial Statements and Supplementary Data, Note 20, incorporated herein by reference.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them, and often consult with our independent accountants about the appropriate interpretation and application of these policies. The preparation of our financial statements requires the selection and application of a number of accounting policies. For a discussion of our significant accounting policies, see Item 8, Financial Statements and Supplementary Data, Note 1. We have defined our critical accounting policies as those significant accounting policies that involve critical accounting estimates in the preparation of our financial statements.

We consider a critical accounting estimate to be an accounting estimate recognized in the financial statements that requires us to make assumptions about matters that may be highly uncertain at the time the estimate is made. We believe that an accounting estimate is only considered a critical accounting estimate if changes in those estimates are reasonably likely to occur or if we reasonably could have selected a different estimate, and either of these differences would have resulted in a material impact on our financial condition or results of operations.

Estimates and assumptions about future events and their effects cannot be determined with certainty. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. These estimates may change as new events occur and as additional information is obtained. In addition, management is periodically faced with uncertainties, the outcomes of which are not within our control and will not be known for prolonged periods of time. We have discussed the development and selection of the critical accounting policies and related disclosures with the audit committee of the Board of Directors.

Our critical accounting policies include policies that are related to specific business units, such as price risk management activities and accounting for natural gas and oil producing activities, as well as broad policies that include accounting for environmental reserves and pension and other post retirement benefits. Each of these areas involves complex situations and a high degree of judgment in both the application and interpretation of existing literature and in the development of estimates that impact our financial statements. These critical accounting policies have been identified for the current year, and there may be additional critical accounting policies as and when new accounting pronouncements are adopted. New accounting pronouncements are discussed in the section below entitled *New Accounting Pronouncements Issued But Not Yet Adopted.*

Price Risk Management Activities. We account for our price risk management activities in accordance with the requirements of SFAS No. 133, which requires that we determine the fair value of the derivative instruments we use and reflect them in our balance sheet at their fair values. Changes in the fair value from period to period of all derivative instruments, except cash flow hedges, are recorded in our income statement. Changes in the fair value of derivative instruments used to hedge our cash flows are generally recognized in our income statement when the hedge is settled. Over time, these methods will derive similar results. However, from period to period, income under these methods can differ significantly.

Some of our derivative instruments are traded on active exchanges such as the New York Mercantile Exchange, while others are valued using exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary factors that can have an impact on our results each period is the price assumptions used to value our derivative instruments. Because of our actions to limit our trading activities and exit the trading business, our accessibility to reliable forward market pricing data for purposes of estimating fair value was significantly limited in late 2002. As a result, we obtained valuation assistance from a third party valuation specialist in determining the fair value of our trading and non-trading price risk management activities as of December 31, 2002. Based upon the specialist's input, our estimates of fair value are based upon price curves derived from actual prices observed in the market, pricing information supplied by the specialist and independent pricing sources and models that rely on this forward pricing information. These estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable time under present market conditions, modeling risk, credit risk of our counterparties and operational risks, as needed. We have discontinued applying our ten-year liquidity valuation allowance that we had instituted during the first quarter of 2002 in circumstances where there was uncertainty related to our forward prices in less liquid markets. To the extent that the forward market data received from the third party specialist indicates value beyond ten years, we now include that value in the fair value of our trading and non-trading price risk management activities.

The amounts we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instrument and the transaction being hedged, both at the time we enter into the transaction and on an ongoing basis. By hedging risk, the derivative instrument's value is intended to offset value changes in the item being hedged. However, this is complicated in hedging energy commodities, because energy commodity prices have qualitative and locational differences that can be difficult to hedge effectively. Our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in market conditions.

We evaluate the risk in our trading and non-trading price risk management activities using a Value-at-Risk model to determine the maximum expected one-day unfavorable impact on our financial performance due to normal market movement. For a discussion of our methodology in calculating Value-at-Risk, please see Item 7A, Quantitative and Qualitative Disclosures About Market Risk. We believe that using this Value-at-Risk methodology captures many of the uncertainties associated with the estimates in our trading and non-trading activities.

We have reflected our trading portfolio at estimated fair value which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. However, the value we ultimately receive in settlement of our trading activities may be less than our fair value estimates. As disclosed previously, we are actively liquidating our trading portfolio, which include approximately 40,000 transactions as of December 31, 2002. We believe the net realizable value of our trading portfolio may be less than their currently estimated fair value. Our belief is based on recent transactions completed at values below estimated fair value and bids received on transactions that were also below their fair value. Additionally, because of the adoption of EITF Issue No. 02-3, a portion of the transactions that we plan to liquidate are accounted for under the accrual method and are not recorded on our balance sheet. Should we have to pay counterparties to assume these transactions, future losses will result. We believe that the amount we may ultimately realize from the liquidation of our total portfolio (including our accrual-based portfolio) could result in future losses up to $200 million.

Asset Impairments. The asset impairment accounting rules require us to determine if an event has occurred indicating that a long-lived asset may be impaired. In some cases, these events are clear. In most cases, however, a clearly identifiable triggering event does not occur. Rather, a series of individually insignificant events occur over time leading to an indication that an asset may be impaired. This can be further complicated where we have investments in foreign countries or where we have projects where we are not the operator. We continually monitor our businesses and the market and business environments in which we operate and make judgments and assessments about whether a triggering event has occurred. If an event occurs, we make an estimate of our future cash flows from these assets to determine if the asset is impaired. For investments, we evaluate whether events and possible outcomes indicate that a decline in the value of our investment has occurred that is other than temporary. The impairment analysis generally involves an assessment of project level cash flows that requires us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our estimates of impairment. In addition, further changes in the economic and business environment can impact our original and ongoing assessments of potential impairment.

Accounting for Environmental Reserves. We accrue for environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Estimates of our liabilities are based on 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 onsite, offsite and groundwater technical studies, and legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency or other organizations. These estimates are subject to revision in future periods based on actual costs or new or changing circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each exposure.

As of December 2002, we had accrued approximately $482 million for environmental matters, including approximately $463 million for expected remediation costs at current and former operating sites and associated onsite, offsite and groundwater technical studies, and approximately $19 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $15 million of the accrual was related to discontinued coal mining operations. The high end of our reserve estimates was approximately $620 million and the low end was approximately $427 million, and our accrual at December 31, 2002 was based on the estimated most likely reasonable amount of liability. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	December 31, 2002	
Sites	**Low**	**High**
	(In millions)	
Operating	$208	$287
Non-operating	193	286
Superfund	26	47

Accounting for Natural Gas and Oil Producing Activities. We use the full cost method to account for our natural gas and oil producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the exploration, acquisition and development of natural gas and oil reserves in full cost pools maintained by geographic areas, regardless of whether reserves are actually located. This method differs from the successful efforts method of accounting for these activities. The primary differences between these two methods are the treatment of exploratory dry hole costs and geological and geophysical costs and the recognition of gains or losses when properties are sold. Exploratory dry hole costs include exploration, acquisition and development costs on wells that do not yield measurable reserves. Under the successful efforts method, these costs are generally expensed when the determination is made that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts. Under the full cost method, both dry hole costs and geological costs are capitalized into the full cost pool. As a result, our financial statements will differ from companies that apply the successful efforts method since we could potentially reflect a higher level of capitalized costs as well as a higher depletion rate.

Under the full cost accounting method, we are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This impairment test is referred to as a ceiling test. Our total capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. 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. The primary factors that could result in a ceiling test write-down include lower prices, higher capitalized costs in the full cost pool, a lower reserve base, and the impact of our hedging program.

The ceiling test calculation assumes that the price in effect on the last day of the quarter is held constant over the life of the reserves. As a result of this pricing assumption, the resulting value is not indicative of the true fair value of the reserves. The prices of natural gas and oil are volatile and change from period to period. We attempt to realize more determinable cash flows through the use of hedges, but a decline in commodity prices can impact the results of our ceiling test. Ceiling test charges due to fluctuating prices, as opposed to reductions to the underlying reserve quantities, should not be considered an absolute indicator of the value of the related reserves.

The process of estimating natural gas and oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates. Our reserve estimates impact several financial calculations. If all other factors are held constant, an increase in estimated proved reserves decreases our unit of production depletion rate. Higher reserves can also reduce the likelihood of ceiling test impairments. Estimated reserves are used to calculate projected future cash flows from our natural gas and oil properties, which can often be used as collateral to secure financing for our operations. For further discussion of our reserves, see Part I, Item 1, Business, under Production segment and Item 8, Financial Statements and Supplementary Data, Note 28.

Accounting for Pension and Other Postretirement Benefits

Our accruals related to our pension and other postretirement benefits are based on actuarial calculations. In performing these calculations, our actuaries must use assumptions, including those related to the return that we expect to earn on our plan assets, discount rates used in calculating benefit obligations, the rate at which we expect the compensation of our employees will increase over the plan term, the cost of health care when benefits are provided under our plans and other factors.

Actual results may differ from the assumptions included in these actuarial calculations, and as a result our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future, with either a negative or positive effect on the costs we recognize and the accruals we make. The following table shows the impact of a one percent change in our primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2002 (in millions):

	Pension Benefits		Postretirement Benefits	
	Net Benefit Expense (Income)	Projected Benefit Obligation	Net Benefit Expense (Income)	Accumulated Postretirement Benefit Obligation
One percent increase in:				
Discount rates	$ 1	$(186)	$—	$(40)
Expected return on plan assets	(30)	—	(1)	—
Rate of compensation increase	2	5	—	—
Health care cost trends	—	—	1	20
One percent decrease in:				
Discount rates	$ (2)	$ 222	$—	$ 42
Expected return on plan assets	30	—	1	—
Rate of compensation increase	(1)	(5)	—	—
Health care cost trends	—	—	(1)	(19)

Our estimates for our net benefit expense (income) are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred and recognized over three years. Due to recent losses in our pension plan assets, the fair value of plan assets used to determine the 2002 net benefit expense (income) was less than the market-related value of plan assets. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit income would have been $51 million lower for the year ended December 31, 2002.

We have not recorded an additional pension liability for our primary pension plan because the fair value of plan assets exceeded the accumulated benefit obligation in that plan as of September 30, 2002, by approximately $130 million. Plan assets exceeded accumulated benefit obligations as of December 31, 2002, by a similar margin. If the accumulated benefit obligation exceeded plan assets under this primary pension plan as of September 30, 2002, we would have recorded a pre-tax additional pension liability of approximately $900 million plus an amount equal to the excess of the accumulated benefit obligation over plan assets of the primary pension plan. We would have also recorded an amount equal to this additional pension liability to accumulated other comprehensive loss, net of taxes, in our balance sheet.

For further details on these and our other significant accounting policies, and the estimates, assumptions and judgments we use in applying these policies, see Item 8, Financial Statements and Supplementary Data, Note 1.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2002, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Accounting for Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement requires companies to record a liability for the estimated retirement and removal costs of long-lived assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We expect that we will record a charge as a cumulative effect of accounting change of approximately $23 million, net of income taxes, upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of $184 million and non-current retirement liabilities of $214 million on January 1, 2003. Our liability relates primarily to our obligations to plug abandoned wells in our Production and Pipelines segments over the next one to 101 years.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Guarantees

In November 2002, the FASB issued FIN No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* This interpretation requires that companies record a liability for all guarantees issued after January 31, 2003, including financial, performance and fair value guarantees. This liability is recorded at its fair value upon issuance and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included these required disclosures in Item 8, Financial Statements and Supplementary Data, Note 20.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003, for all variable interest entities created before January 31, 2003. We are currently evaluating the effects of this pronouncement, but have reached several tentative conclusions about the possible impact of this interpretation on us. See Item 8, Financial Statements and Supplementary Data, Note 1, for a discussion of the conclusions reached.

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 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. All of our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Commission from time to time and 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 have substantial debt. The downgrades of our credit ratings to below investment grade have significantly impacted and will continue to significantly impact our liquidity.

We have substantial debt. As of December 31, 2002, we had total long-term capital market debt, bank debt and other financing obligations of approximately $16.7 billion, including approximately $8.5 billion of subsidiary debt. We also have guarantees of approximately $2.5 billion and preferred interests of consolidated subsidiaries of approximately $3.3 billion.

The ratings assigned to our outstanding senior unsecured indebtedness have been downgraded to below investment grade, currently rated Caa1 by Moody's and B by Standard & Poor's, and we remain on negative outlook at both agencies. These ratings have increased and will increase our cost of capital and collateral requirements, and could impede our access to capital markets. As a result of these recent downgrades, we have realized substantial demands on our liquidity, which demands have included:

- application of cash required to be withheld from our cash management program in order to redeem preferred membership interests at one of our minority interest financing structures; and
- cash collateral or margin requirements associated with contractual commitments of our subsidiaries.

These downgrades may subject us to additional liquidity demands in the future. These downgrades are a result, at least in part, of the outlook generally for our consolidated businesses and our liquidity needs.

In order to meet our short-term liquidity needs, we have embarked on our 2003 Operational and Financial Plan that contemplates drawing all or part of our availability under our existing bank facilities and consummating significant asset sales. In addition, we may take additional steps, such as entering into other financing activities, renegotiating our credit facilities and further reducing capital expenditures, which should provide additional liquidity. There can be no assurance that these actions will be consummated on favorable terms, if at all, or that even if consummated, that such actions will be successful in satisfying our liquidity needs. In the event our liquidity needs are not satisfied, we could be forced to seek protection from our creditors in bankruptcy. Such a development could materially adversely affect our financial condition.

Ongoing litigation and investigations could significantly adversely affect our business.

On March 20, 2003, we entered into an agreement in principle (the Western Energy Settlement) with various public and private claimants, including the states of California, Washington, Oregon, and Nevada, to resolve the principal litigation, claims, and regulatory proceedings against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the Western Energy Settlement. For further information on these matters, see Part II, Item 8, Financial Statements and Supplementary Data, Notes 2 and 20. If we are unable to negotiate definitive settlement agreements, or if the settlement is not approved by the courts or the FERC, the proceedings and litigation will continue.

Since July 2002, twelve purported shareholder class action suits alleging violations of federal securities laws have been filed against us and several of our officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge. The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 challenging the accuracy or completeness of our February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002. It has since been dismissed, in light of similar claims being asserted in the consolidated suits in Houston. Four shareholder derivative actions have also been filed. One shareholder derivative lawsuit was filed in federal court in Houston in August 2002. This derivative action generally alleges the same claims as those made in the shareholder class action, has been consolidated with the shareholder class actions pending in Houston and has been stayed. A second shareholder derivative lawsuit was filed in Delaware State Court in October 2002 and generally alleges the same claims as those made in the consolidated shareholder class action lawsuit. A third shareholder derivative suit was filed in state court in Houston in March 2002, and a fourth shareholder derivative suit was filed in state court in Houston in November 2002. The third and fourth shareholder derivative suits both generally allege that manipulation of California gas supply and gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. In December 2002, another action was filed in federal court in Houston on behalf of participants in the El Paso Corporation Retirement Savings Plan. At this time, our legal exposure related to these lawsuits and claims is not determinable.

If we do not prevail in these cases (or any of the other litigation, administrative or regulatory matters to which we are, or may be, a party described in Item 8, Financial Statements and Supplementary Data, Note 20), and if the remedy adopted in these cases substantially impairs our financial position, the long-term adverse impact on our credit rating, liquidity and our ability to raise capital to meet our ongoing and future investing and financing needs could be substantial.

We may not achieve all of the objectives set forth in our 2003 Operational and Financial Plan in a timely manner or at all.

Our ability to achieve the stated objectives of our 2003 Operational and Financial Plan, as well as the timing of their achievement, if at all, is subject to factors beyond our control, including our ability to raise cash from asset sales, which may be impacted by our ability to locate potential buyers in a timely fashion and obtain a reasonable price or by competing assets sales programs by our competitors. If we fail to timely achieve that plan, or if the plan, even if achieved, fails to have the effects on our liquidity and financial position that we anticipate, our liquidity or financial position could be materially adversely affected.

Our objectives in exiting the energy trading business and the petroleum business may not be achieved in the time period or in the manner we expect, if at all.

In November 2002, we announced our intention to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. In February 2003, we announced our intention to sell our remaining petroleum assets, excluding the Aruba refinery. If we are unable to achieve these objectives in the time period or the manner that we expect, it could have a substantial negative impact on our cash flows, liquidity and financial position. The ability to achieve our goals in the liquidation of our trading portfolio is subject to factors beyond our control, including, among others, liquidity constraints experienced by the counterparties in our energy trading business, obtaining maximum cash flow from our trading portfolio and isolating the credit and liquidity needs of the energy trading business from the rest of our business. Additionally, any amounts actually realized from the liquidation of the energy trading business could be significantly less than the amounts we currently expect from such liquidations. Ongoing losses from our trading business are expected to be incurred as positions are liquidated. The ability to achieve our goals in the sale of our petroleum assets is subject to factors beyond our control, including, among others, our ability to locate potential buyers in a timely fashion and obtain a reasonable price, and competing asset sales programs by our competitors.

The proxy contest initiated by Selim Zilkha to replace our board of directors could have a material adverse effect on us.

On February 18, 2003, Selim Zilkha, one of our stockholders, announced his intention to initiate a proxy solicitation to replace our entire board of directors with his own nominees, and on March 11, 2003, Mr. Zilkha filed his preliminary proxy statement to that effect with the SEC. This proxy contest may be disruptive and may negatively impact our ability to achieve the stated objectives of our 2003 Operational and Financial Plan. In addition, we may have difficulty attracting and retaining key personnel until such proxy contest is resolved. Therefore, this proxy contest, whether or not successful, could have a material adverse effect on our liquidity and financial condition.

Results of investigations into reporting of trading information could adversely affect our business.

In response to an October 2002 data request from the FERC, we conducted an investigation into the accuracy of information that employees of El Paso Merchant Energy, our subsidiary, voluntarily reported to trade publications. As a part of that investigation, we discovered that inaccurate information was submitted to the trade publications. One of El Paso Merchant Energy's former employees has been arrested and charged with knowingly submitting inaccurate data to a trade publication. We have continued our policy of cooperation with the office of the U.S. Attorney and the FERC and intend to take whatever remedial steps are necessary to ensure that our operations are conducted with integrity. However, these investigations are continuing, and there can be no assurance that penalties or sanctions will not be imposed on us, which, in turn, could adversely affect our business.

The success of our pipeline and field services businesses depends on factors beyond our control.

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 throughput, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity:

- future weather conditions, including those that favor alternative energy sources;
- price competition;
- drilling activity and supply availability;
- expiration and/or turn back of significant capacity;
- service area competition;
- changes in regulation and action of regulatory bodies;
- credit risk of customer base;
- increased cost of capital; and
- natural gas and liquids prices.

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 contracts which expire periodically and must be renegotiated and extended or replaced. We cannot assure 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 contracts could be adversely affected 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 or turn back their capacity when their contracts expire;
- reduced demand and market conditions;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

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 pipeline and field services businesses.

Revenues generated by our transmission, storage, 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. Increased prices could result in loss of load from our customers, such as power companies not dispatching gas fired plants, industrial plant shutdown or load loss to competitive fuels and local distribution companies' loss of customer base. The success of our transmission, gathering and processing operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional suppliers from interconnecting pipelines 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 transmission, gathering and processing through our systems or facilities. Fluctuations in energy prices 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;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

The agencies that regulate our pipeline businesses and their customers affect our profitability.

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. If our pipelines' tariff rates were reduced in a future proceeding, if our pipelines' volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition, the profitability of our pipeline businesses could be reduced.

Further, state agencies that regulate our pipelines' local distribution company customers could impose requirements that could impact demand for our pipelines' services.

The success of our natural gas and oil exploration and production businesses is dependent on factors that are beyond our control.

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

- fluctuations in natural gas and crude oil prices including basis differentials;
- 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;
- increased competition in the search for and acquisition of reserves;
- risks incident to operations of natural gas and oil wells;
- future drilling, production and development costs, including drilling rig rates and oil field services costs;
- future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;
- increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives; and
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

Estimates of natural gas and oil 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 natural gas and oil, and those variances may be material. The process of estimating natural gas and oil 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, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves may vary substantially from our estimates. In addition, we may be required to revise the reserve information, downward or upward, based on production history, results of future exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

The success of our power generation activities depends on many factors beyond our control.

The success of our domestic and international power projects 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;
- increases in the costs of generation, including increases in fuel costs;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the U.S. 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, excessive reserve margins and the implementation of conservation programs;
- risks incidental to the operation and maintenance of power generation facilities;
- 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 use of derivative financial instruments could result in financial losses.

Some of our subsidiaries use futures, swaps 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. We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments involve estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase, or interest rates were to change. The use of derivatives also requires the posting of cash collateral with our counterparties which can impact our working capital when commodity prices or interest rates change. For additional information concerning our derivative financial instruments, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Item 8, Financial Statements and Supplementary Data, Note 13.

Our foreign operations and 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 risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of 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 operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which 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 uncertainties in estimating clean up costs;
- the discovery of new sites or information;
- 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 20.

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

Terrorist attacks aimed at our energy operations could adversely affect our business.

On September 11, 2001, the U.S. was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, the U.S. government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be a future target of terrorist organizations. These developments have subjected our energy operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other energy companies, could have a material adverse effect on our business.

A breach of the covenants applicable to our long-term debt and other financial obligations could accelerate our long-term debt and other financial obligations and that of our subsidiaries.

Our long-term debt and other financial obligations contain restrictive covenants and cross-acceleration provisions. A breach of any of these covenants could accelerate our long-term debt and other financial obligations and that of our subsidiaries. If this were to occur, we may not be able to repay such long-term debt and other financing obligations upon such acceleration.

We are subject to financing and interest rate exposure risks.

Our future success depends on our ability to access capital markets and obtain financing at cost effective rates. In addition, our recent downgrades and current credit ratings have triggered higher cash requirements and operating costs for our energy trading business, which we are in the process of exiting pursuant to an orderly liquidation of our trading portfolio. Our ability to access financial markets and obtain cost-effective rates in the future are dependent on a number of factors, many of which we cannot control, including changes in:

- our credit ratings;
- interest rates;
- the structured and commercial financial markets;
- market perceptions of us or the natural gas and energy industry;
- tax rates due to new tax laws; and
- our stock price.

We will face competition from third parties to produce, transport, gather, process, fractionate, store or otherwise handle oil, natural gas, natural gas liquids and other petroleum products.

The natural gas and oil business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of natural gas and oil production. Our competitors include the major oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. If we are unable to compete effectively with services offered by other energy enterprises, our future profitability may be negatively impacted.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We use derivative financial instruments and energy related contracts to manage market risks associated with energy commodities, interest rates and foreign currency exchange rates. Our primary market risk exposures are those related to changing commodity prices. Our market risks are monitored by a corporate risk management committee to ensure compliance with the stated risk management policies approved by the Audit Committee of our Board of Directors. This committee operates independently from the business segments that create or manage these risks.

Commodity Price Risk

We are exposed to a variety of market risks in the normal course of our business activities. The nature of these market price risks varies based on our segments. Our Production segment has price risks related to the natural gas and oil it produces. Our Field Services segment has price risks related to the natural gas liquids it retains in its processing operations. The global power division of our Merchant Energy segment is exposed to price risks in both the fuel it uses, primarily natural gas and coal, as well as the power it sells. The petroleum division of our Merchant Energy segment is exposed to price risks in both the feedstocks it uses, primarily crude oil and petroleum-based products, as well as the refined products it sells. The energy trading division of our Merchant Energy segment is exposed to market price risks inherent in its contractual obligations to deliver or receive commodities and in the financial instruments it uses for trading energy and energy-related commodities.

We attempt to mitigate price risk associated with both our energy trading activities (included in our energy trading and petroleum divisions in Merchant Energy) and non-trading activities (power and commodity hedging activities) through the use of trading and non-trading financial instruments (including forwards, swaps, options and futures). We measure risks from our commodity and energy-related contracts on a daily basis using a Value-at-Risk model. This model allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to normal market movements, and monitors our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique values positions in every iteration of the simulation and captures risk from all types of financial positions. We also use other measures to monitor our risks on a daily basis, including sensitivity analysis, stress testing, credit risk management and other measures to monitor and measure risk exposure.

The following table presents our maximum expected one-day unfavorable impact on the fair values of our commodity and energy-related contracts as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period. The high and low valuations represent the highest and lowest of the month end values during 2002. The average valuation represents the average of the 2002 month end values. Actual losses in fair value may exceed those measured by Value-at-Risk:

	Value-at-Risk				
	2002				2001
	Year end	High	Low	Average	Year end
	(In millions)				
Trading Value-at-Risk	$ 8	$23	$ 8	$16	$18
Non-trading Value-at-Risk	8	10	4	7	15
Portfolio Value-at-Risk(1)	11	22	9	16	17

(1) Portfolio Value-at-Risk represents the combined Value-at-Risk for the trading and non-trading commodity and energy-related contracts. The separate calculation of Value-at-Risk for trading and non-trading commodity contracts ignores the natural correlation that exists between traded and non-traded commodity contracts and prices. As a result, the sum of the individually determined values will be higher than the combined Value-at-Risk in most instances. We manage our risks through a portfolio approach that balances both trading and non-trading risks.

The $10 million decrease in trading Value-at-Risk during 2002 is attributable to our efforts to limit and liquidate our trading activities during 2002. Our non-trading Value-at-Risk decreased by $7 million in 2002 due to a reduction of our hedged volumes of future natural gas production during 2002. We reduced these hedged volumes to reduce the cash requirements of our non-trading price risk management activities.

Interest Rate Risk

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted average interest rates on our interest-bearing securities, by expected maturity dates and the fair values of those securities. As of December 31, 2002, 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 securities has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2002								December 31, 2001	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(Dollars in millions)									
Liabilities:										
Short-term debt — variable rate	$1,500	—	—	—	—	—	$ 1,500	$ 1,500	$ 1,515	$ 1,515
Average interest rate	2.7%									
Long-term debt, including current portion — fixed rate	$ 362	$331	$497	$1,120	$1,122	$12,469	$15,901	$11,488	$12,533	$12,007
Average interest rate	7.8%	7.4%	8.5%	8.3%	7.7%	8.0%				
Long-term debt, including current portion-variable rate	$ 213	$253	$113	$ 113	$ 9	$ 79	$ 780	$ 780	$ 2,082	$ 2,082
Average interest rate	2.5%	4.4%	2.9%	2.7%	2.7%	6.1%				
Notes payable to unconsolidated affiliates — fixed rate	$ 189	$ 10	$ 12	$ 6	—	—	$ 216	$ 206	$ 515	$ 539
Average interest rate	4.4%	7.3%	7.3%	7.3%						
Notes payable to unconsolidated affiliates — variable rate	—	—	—	—	—	$ 174	$ 174	$ 174	$ 357	$ 357
Average interest rate						10.4%				
Company-obligated preferred securities:										
El Paso Energy Capital Trust I	—	—	—	—	—	$ 325	$ 325	$ 118	$ 325	$ 370
Average interest rate						4.8%				
Coastal Finance I	—	—	—	—	—	$ 300	$ 300	$ 160	$ 300	$ 378
Average fixed interest rate						8.4%				

The fair value of our long-term securities was significantly impacted by a series of ratings actions initiated by Moody's and Standard & Poor's that lowered our unsecured debt rating to Caa1 and B (both "below investment grade" ratings), and we remain on negative outlook. These rating actions decreased the fair value of all of our fixed rate long-term securities during 2002.

Foreign Currency Exchange Rate Risk

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. We have Euro-denominated debt with a principal amount of 1,050 million euros, or $1,100 million at a Euro/USD spot exchange rate of 1.0492 as of December 31, 2002. 550 million euros and 500 million euros of this debt mature in 2006 and 2009. We have a foreign currency swap that converts 275 million euros of this debt to U.S. dollars at a fixed rate of 0.9275. The remaining principal of 775 million euros is unhedged and is subject to foreign currency exchange risk. A ten percent increase or decrease in the Euro/USD exchange rate would increase or decrease the carrying value of our unhedged Euro-denominated debt by approximately $81 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

Below is an index to the financial statements and notes contained in 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,		
	2002	2001	2000
Operating revenues			
Pipelines	$ 2,605	$ 2,748	$ 2,741
Production	2,126	2,347	1,686
Field Services	2,029	2,553	1,439
Merchant Energy	5,590	6,075	13,000
Corporate and eliminations	(156)	(74)	405
	12,194	13,649	19,271
Operating expenses			
Cost of products and services	6,447	6,353	12,863
Operation and maintenance	2,606	2,876	2,408
Restructuring and merger-related costs	81	1,520	93
(Gain) loss on long-lived assets	282	183	(5)
Western Energy Settlement	899	—	—
Ceiling test charges	269	135	—
Depreciation, depletion and amortization	1,405	1,327	1,231
Taxes, other than income taxes	277	334	266
	12,266	12,728	16,856
Operating income (loss)	(72)	921	2,415
Earnings (losses) from unconsolidated affiliates	(234)	450	428
Minority interest in consolidated subsidiaries	(58)	(2)	—
Other income	248	396	234
Other expenses	(109)	(136)	(57)
Interest and debt expense	(1,400)	(1,156)	(1,040)
Returns on preferred interests of consolidated subsidiaries	(159)	(217)	(204)
Income (loss) before income taxes	(1,784)	256	1,776
Income taxes	(495)	184	539
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(1,289)	72	1,237
Discontinued operations, net of income taxes	(124)	(5)	(1)
Extraordinary items, net of income taxes	—	26	70
Cumulative effect of accounting changes, net of income taxes	(54)	—	—
Net income (loss)	$(1,467)	$ 93	$ 1,306
Basic earnings per common share			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (2.30)	$ 0.14	$ 2.50
Discontinued operations, net of income taxes	(0.22)	(0.01)	—
Extraordinary items, net of income taxes	—	0.05	0.14
Cumulative effect of accounting changes, net of income taxes	(0.10)	—	—
Net income (loss)	$ (2.62)	$ 0.18	$ 2.64
Diluted earnings per common share			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (2.30)	$ 0.14	$ 2.43
Discontinued operations, net of income taxes	(0.22)	(0.01)	—
Extraordinary items, net of income taxes	—	0.05	0.14
Cumulative effect of accounting changes, net of income taxes	(0.10)	—	—
Net income (loss)	$ (2.62)	$ 0.18	$ 2.57
Basic average common shares outstanding	560	505	494
Diluted average common shares outstanding	560	516	513

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,591	$ 1,148
Accounts and notes receivable		
Customer, net of allowance of $192 in 2002 and $130 in 2001	5,315	5,138
Affiliates	798	934
Other	464	649
Inventory	888	815
Assets from price risk management activities	1,027	2,702
Margin and other deposits on energy trading activities	1,003	872
Other	838	547
Total current assets	11,924	12,805
Property, plant and equipment, at cost		
Pipelines	18,049	17,595
Natural gas and oil properties, at full cost	14,940	14,466
Refining, crude oil and chemical facilities	2,556	2,524
Gathering and processing systems	1,101	2,628
Power facilities	1,058	834
Other	651	608
	38,355	38,655
Less accumulated depreciation, depletion and amortization	14,745	14,250
Total property, plant and equipment, net	23,610	24,405
Other assets		
Investments in unconsolidated affiliates	4,907	5,297
Assets from price risk management activities	1,844	2,118
Intangible assets, net	1,370	1,425
Other	2,569	2,496
	10,690	11,336
Total assets	$46,224	$48,546

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)

	December 31, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 4,699	$ 4,939
Affiliates	29	26
Other	777	959
Short-term financing obligations, including current maturities	2,075	3,239
Notes payable to affiliates	189	504
Liabilities from price risk management activities	1,073	1,868
Margin and other deposits from customers on energy trading activities	123	1,147
Western Energy Settlement	100	—
Other	1,285	1,254
Total current liabilities	10,350	13,936
Debt		
Long-term financing obligations	16,106	12,891
Notes payable to affiliates	201	368
	16,307	13,259
Other		
Liabilities from price risk management activities	1,376	1,231
Deferred income taxes	3,576	4,388
Western Energy Settlement	799	—
Other	2,019	2,363
	7,770	7,982
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	3,255	3,955
Minority interests of consolidated subsidiaries	165	58
	3,420	4,013
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares and issued 605,298,466 shares in 2002; authorized 750,000,000 shares and issued 538,363,664 shares in 2001	1,816	1,615
Additional paid-in capital	4,444	3,130
Retained earnings	2,942	4,902
Accumulated other comprehensive income (loss)	(529)	157
Treasury stock (at cost); 5,730,042 shares in 2002 and 7,628,799 shares in 2001	(201)	(261)
Unamortized compensation	(95)	(187)
Total stockholders' equity	8,377	9,356
Total liabilities and stockholders' equity	$46,224	$48,546

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities			
Net income (loss)	$(1,467)	$ 93	$ 1,306
Less loss from discontinued operations, net of income taxes	(124)	(5)	(1)
Net income (loss) from continuing operations	(1,343)	98	1,307
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	1,405	1,327	1,231
Western Energy Settlement	899	—	—
Ceiling test charges	269	135	—
Deferred income tax expense (benefit)	(520)	200	612
Non-cash portion of merger-related costs and changes in estimates	—	1,215	(21)
(Gain) loss on long-lived assets	282	183	(5)
Undistributed equity (earnings) losses from unconsolidated affiliates	547	(40)	(109)
Non-cash (gain) loss from trading and power restructuring activities	48	(852)	(443)
Other non-cash income items	372	140	(63)
Working capital changes, net of non-cash transactions	(1,436)	1,914	(2,334)
Non-working capital changes and other	(177)	(207)	(89)
Cash provided by continuing operations	346	4,113	86
Cash provided by discontinued operations	90	7	13
Net cash provided by operating activities	436	4,120	99
Cash flows from investing activities			
Additions to property, plant and equipment	(3,716)	(4,023)	(3,379)
Equity investments	(299)	(956)	(1,492)
Cash paid for acquisitions, net of cash acquired	45	(299)	(524)
Net proceeds from the sale of assets	2,554	548	787
Proceeds from the sale of investments	391	354	354
Net change in restricted cash	(244)	3	24
Net change in notes receivable from unconsolidated affiliates	4	(606)	466
Other	22	12	(1)
Cash used in continuing operations	(1,243)	(4,967)	(3,765)
Cash used in discontinued operations	(12)	(56)	(69)
Net cash used in investing activities	(1,255)	(5,023)	(3,834)
Cash flows from financing activities			
Net short-term borrowings (repayments)	60	(786)	309
Net long-term borrowings	1,457	1,277	2,419
Net proceeds from issuance of preferred securities	—	—	293
Payments to minority interest holders	(161)	—	—
Payments to preferred interest holders	(700)	—	—
Issuances of common stock	1,053	915	141
Dividends paid	(470)	(387)	(243)
Proceeds from issuance of minority interests	33	281	995
Contributions from (distributions to) discontinued operations	68	(43)	(57)
Cash provided by continuing operations	1,340	1,257	3,857
Cash provided by (used in) discontinued operations	(68)	43	57
Net cash provided by financing activities	1,272	1,300	3,914
Increase in cash and cash equivalents	453	397	179
Less increase (decrease) in cash and cash equivalents related to discontinued operations	10	(6)	1
Increase in cash and cash equivalents from continuing operations	443	403	178
Cash and cash equivalents			
Beginning of period	1,148	745	567
End of period	$ 1,591	$ 1,148	$ 745

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions)

	For the Years Ended December 31,					
	2002		2001		2000	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	538	$ 1,615	514	$ 1,541	507	$1,520
Compensation related issuances	2	5	3	10	6	18
Equity offering	52	155	20	61	—	—
Conversion of Coastal options	—	—	4	13	—	—
Conversion of FELINE PRIDES[SM]	12	37	—	—	—	—
Other	1	4	(3)	(10)	1	3
Balance at end of year	605	1,816	538	1,615	514	1,541
Additional paid-in capital:						
Balance at beginning of year		3,130		1,925		1,667
Compensation related issuances		57		188		171
Tax benefit of equity plans		15		31		60
Equity offering		846		802		—
Retirement of Coastal treasury shares		—		(132)		
Conversion of Coastal options		—		265		—
Conversion of FELINE PRIDES[SM]		423		—		—
Other		(27)		51		27
Balance at end of year		4,444		3,130		1,925
Retained earnings:						
Balance at beginning of year		4,902		5,243		4,180
Net income (loss)		(1,467)		93		1,306
Dividends ($0.870, $0.850 and $0.824 per share)		(493)		(434)		(243)
Balance at end of year		2,942		4,902		5,243
Accumulated other comprehensive income (loss):						
Balance at beginning of year		157		(65)		(37)
Other comprehensive income (loss)		(686)		222		(28)
Balance at end of year		(529)		157		(65)
Treasury stock, at cost:						
Balance at beginning of year	(8)	(261)	(14)	(400)	(14)	(405)
Compensation related issuances	3	79	1	11	—	3
Retirement of Coastal treasury shares	—	—	5	132	—	—
Other	(1)	(19)	—	(4)	—	2
Balance at end of year	(6)	(201)	(8)	(261)	(14)	(400)
Unamortized compensation:						
Balance at beginning of year		(187)		(125)		(41)
Issuance of new restricted stock		(36)		(144)		(82)
Amortization of restricted stock		73		67		13
Market price changes on variable restricted stock awards		40		11		(15)
Forfeitures of restricted stock		15		4		—
Balance at end of year		(95)		(187)		(125)
Total stockholders' equity	599	$ 8,377	530	$ 9,356	500	$8,119

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2002	**2001**	**2000**
Net income (loss)	$(1,467)	$ 93	$1,306
Foreign currency translation adjustments	(18)	(33)	(30)
Pension minimum liability accrual (net of income tax of $20)	(35)	—	—
Net gains (losses) from cash flow hedging activities:			
Cumulative-effect of transition adjustment (net of income tax of $673)	—	(1,280)	—
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $261 and $548 in 2002 and 2001)	(459)	1,042	—
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $96 and $283 in 2002 and 2001)	(174)	494	—
Other	—	(1)	2
Other comprehensive income (loss)	(686)	222	(28)
Comprehensive income (loss)	$(2,153)	$ 315	$1,278

See accompanying notes.

1. Summary of Significant Events and Accounting Policies

Significant Events

Overview of Industry Developments

During 2002, we experienced dramatic changes in our industry as well as in the financial markets on which we rely. In response to industry events, the credit rating agencies, including Moody's and Standard & Poor's, re-evaluated the ratings of companies involved in energy trading activities. As a result, the ratings of many of the largest participants in the energy trading industry, including us, were downgraded to below investment grade. Also impacting us was a preliminary decision reached by a FERC administrative law judge (ALJ) that one of our subsidiaries withheld pipeline capacity from the California market during 2000 and 2001. Reacting to the changes in the market, our leverage and a preliminary decision by the FERC on our California matters, Moody's and Standard & Poor's initiated a series of ratings actions lowering our senior unsecured debt rating to Caa1 and B (both "below investment grade" ratings), and we remain on negative outlook.

Several negative outcomes resulted from these downgrades. First, cash generated in 2002 from the sales of assets, which had originally been identified for debt reductions, was instead required to be posted as additional cash collateral in connection with our commercial trading activities, paid to meet financial guarantees and used to meet other arrangements. Additionally, our access to capital markets and commercial paper markets became more restricted because of our lower credit ratings. Finally, the credit downgrades have resulted in the net cash generated by the assets in two of our minority interest financing arrangements being largely unavailable to us for general corporate purposes. Instead, we were required to use this cash to redeem preferred securities issued in connection with those arrangements and for the operation of the businesses that collateralize those arrangements. In March of 2003, we redeemed the outstanding amounts under one of these financing arrangements, partially freeing up these cash usage restrictions. For a further discussion of this, see Note 19.

Liquidity Developments

We rely on cash generated from our operations as our primary source of liquidity. We also expect to rely on borrowings under available credit facilities, bank financings, asset sales and the issuance of long-term debt, preferred and equity securities to provide liquidity as needed and for overall flexibility. We believe that our future working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources of liquidity. Since the fourth quarter of 2001, we have taken a number of actions to address our liquidity issues, and have made progress in our plans to meet the demands on our liquidity and strengthen our capital structure.

Our accomplishments have included the sale of over $2.5 billion of equity or equity-related securities, the completion or announcement of over $5.5 billion of asset sales, the removal of over $4 billion of rating triggers from our investment and financing programs, which would have resulted in issuance of common stock or the accelerated repayment of these obligations, and the announcement of a plan to exit our trading business and minimize our involvement in the LNG business. On February 5, 2003, we announced our 2003 Operational and Financial Plan. This plan is based on five key principles:

- Preserving and enhancing the value of our core natural gas and pipeline businesses;
- Exiting non-core businesses quickly, but prudently;
- Strengthening and simplifying our balance sheet, while maximizing liquidity;

• Aggressively pursuing additional cost reductions; and

• Continuing to work diligently to resolve litigation and regulatory matters.

Through March 2003, we have made further progress in accomplishing our objectives under this plan, including (i) the finalization of a new $1.2 billion term loan, which allowed us to retire our Trinity River preferred interest financing arrangement and eliminate the cash restrictions and accelerated amortization requirements of that arrangement (ii) the repayment of over $1.9 billion of financial obligations, including Electron and Trinity River, (iii) the issuance of $700 million in bonds at two of our wholly owned subsidiaries and (iv) the announcement of an agreement in principle to settle the principal claims asserted against us in the western energy crisis of 2001.

We believe the accomplishment of this announced plan will enable us to address our liquidity issues and simplify and improve our capital structure. However, a number of factors could influence the timing and ultimate outcome of our efforts.

Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications did not impact our reported net income or stockholders' equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity. Discussed below as part of new accounting principles issued but not yet adopted is a standard that, once effective, will impact our consolidation principles.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues, and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our interstate natural gas systems and storage operations are subject to the regulations and accounting procedures of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Our interstate systems, including TGP, EPNG, SNG and MPC, apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. ANR, CIG and WIC discontinued the application of SFAS No. 71 in 1996. Accounting for regulated businesses that apply the provisions of SFAS No. 71 differs from the accounting requirements for regulated businesses that do not apply SFAS No. 71. 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, depreciation and other costs and taxes included in, or expected to be included in, future rates.

Our application of SFAS No. 71 is based on the current regulatory environment and our current tariff rates. Future regulatory developments and rate cases could impact this accounting. Things that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the ratemaking process and FERC proceedings;
- excess capacity;
- discounting rates in the markets we serve; and
- impacts of ongoing initiatives in, and deregulation of, the natural gas industry.

We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment.

Cash and Cash Equivalents

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

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of December 31, 2002 and 2001, we reported $124 million and $17 million as other current assets and $212 million and $75 million as other non-current assets.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Inventory

Our inventory consists of refined products, crude oil and chemicals, materials and supplies, natural gas in storage, coal and optic fiber. We also hold power turbines in inventory. We classify inventory as current or non-current based on whether it will be sold or used in the next twelve months. We report non-current inventory as part of other non-current assets in our balance sheets. We use the first-in, first-out and average cost methods to account for our refined products, crude oil and chemicals inventories and the average cost method to account for our other inventories. We value all inventory at the lower of its cost or market value. On October 1, 2002, we adopted the provisions of Emerging Issues Task Force (EITF) Issue No. 02-3, which required us to reclassify all physical commodity inventory used in trading activities from net assets from price risk management activities to inventory on our balance sheet and to adjust this inventory to the lower of cost or market. See *Price Risk Management Activities* below for a further discussion of this accounting change.

Natural Gas and Oil Imbalances and Exchanges

Natural gas and oil imbalances occur when the actual amount of natural gas or oil delivered from or received by a pipeline system, processing plant or storage facility differs from the contractual amount scheduled to be delivered or received. Natural gas exchange transactions involve receiving or delivering natural gas inventory that will be made up in-kind. We value these imbalances and exchanges due to or from shippers and operators at an appropriate market index price. Imbalances and exchanges are settled in cash or made up in-kind, subject to the contractual terms of settlement and tariffs.

Imbalances and exchanges due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from unconsolidated affiliates. Imbalances and exchanges owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to unconsolidated affiliates. In addition, all imbalances and exchanges are classified as current or long-term depending on when we expect to settle them. On October 1, 2002, we adopted the provisions of EITF Issue No. 02-3, which required us to reclassify all natural gas exchanges resulting from trading activities from net assets from price risk management activities to accounts receivable and accounts payable on our balance sheet. See *Price Risk Management Activities* below for a further discussion of this accounting change.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. We capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates.

The following table presents our property, plant and equipment by type, depreciation method, remaining useful lives and depreciation rate:

Type	Method	Remaining Useful Lives	Rates
		(In years)	
Regulated interstate systems			
SFAS No. 71[(1)]	Composite	1-57	1% to 33%
Non-SFAS No. 71	Straight-line	2-50	2% to 25%
Non-regulated systems			
Transmission and storage facilities	Straight-line	60	1% to 3%
Refining, crude oil and chemical facilities	Straight-line	1-33	3% to 20%
Power facilities	Straight-line	3-26	2% to 33%
Gathering and processing systems	Straight-line	1-40	3% to 40%
Transportation equipment	Straight-line	1-30	3% to 33%
Buildings and improvements	Straight-line	1-43	2% to 50%
Office and miscellaneous equipment	Straight-line	1-20	4% to 50%

(1) For our regulated interstate systems that apply SFAS No. 71, we use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff to the total cost of the group until its net book value equals its salvage value. We re-evaluate depreciation rates each time we redevelop our transportation rates when we file with the FERC for an increase or decrease in rates.

When we retire regulated property, plant and equipment accounted for under SFAS No. 71, we charge accumulated depreciation and amortization for the original cost, plus 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. When we retire regulated property, plant and equipment not accounted for under SFAS No. 71 and non-regulated properties, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage value. Any remaining gain or loss is recorded in income.

We capitalize a carrying cost on funds invested in our construction of long-lived assets. This carrying cost consists of (i) an interest cost on the investment financed by debt, which applies to both regulated and non-regulated transmission businesses and (ii) a return on the investment financed by equity, which only applies to regulated transmission businesses that apply SFAS No. 71. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized during the years ended December 31, 2002, 2001 and 2000, were $33 million, $65 million and $82 million. These amounts are included as a reduction of interest expense in our income statements. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized during the years ended December 31, 2002, 2001 and 2000 were $8 million, $8 million and $2 million. These amounts are included as other non-operating income on our income statement. Capitalized carrying cost for debt and equity are reflected as an increase in the cost of the asset on our balance sheet.

Asset Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* to account for asset impairments. Under this standard, we evaluate an asset for impairment when events or circumstances indicate that a long-lived asset's carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset or decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. When we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to the estimated sales price, less costs to sell. We also reclassify the asset or assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flows.

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, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized amounts include the costs of all unproved properties, internal costs directly related to acquisition, development and exploration activities and capitalized interest.

We amortize these costs using the unit of production method over the life of our proved reserves. Each quarter, we calculate the unit of production depletion rate based on our estimated production and an estimate of proved reserves. Capitalized costs associated with unproved properties are excluded from amortizable costs until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in costs subject to amortization.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. 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. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated future natural gas and oil production.

We do not recognize a gain or loss on sales of our natural gas and oil properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves. We treat sales proceeds on non-significant sales as an adjustment to the cost of our properties.

Planned Major Maintenance

Repair and maintenance costs are generally expensed as incurred, unless they improve the operating efficiency or extend the useful life of an asset.

In our domestic refining business, repair and maintenance costs for planned major maintenance activities are accrued as a liability in a systematic and rational manner over the period of time until the planned major maintenance activities occur. Any difference between the accrued liability and the actual costs incurred in performing the maintenance activities are charged or credited to expense at the time the maintenance occurs. At our international refineries, the cost of each major maintenance activity is capitalized and amortized to expense in a systematic and rational manner over the estimated period extending to the next planned major maintenance activity. The types of costs we accrue in conjunction with major maintenance at our refineries are outside contractor costs, materials and supplies, company labor and other outside services. For our domestic operations, we had accruals for major maintenance of $40 million and $36 million at December 31, 2002 and 2001, and for our international operations, we capitalized $75 million and $51 million for the years ended December 31, 2002 and 2001.

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. We apply SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets* to account for these intangibles. Under these standards, we recognize goodwill separately from other intangible assets. In addition, goodwill and intangibles that have indefinite lives are not amortized. Also, goodwill and indefinite lived intangible assets are periodically tested for impairment, at least annually, or whenever an event occurs that indicates that an impairment may have occurred. We adopted these standards on January 1, 2002 and stopped amortizing goodwill. We also recognized a pretax and after-tax gain of $154 million related to the elimination of negative goodwill. We reported this gain as a cumulative effect of an accounting change in our income statement.

SFAS No. 142 requires that we perform impairment tests upon adoption of the standard on January 1, 2002 and at least annually thereafter. The initial impairment tests we performed as of January 1, 2002 indicated no impairment of our goodwill. The impairment tests we performed as of December 31, 2002, however, indicated a pre-tax impairment of our goodwill associated with our Merchant Energy segment's financial services businesses, EnCap and Enerplus, of $44 million. This impairment was recorded in 2002 and was the result of the combined effects of weak financial services industry conditions and our decision not to continue to invest capital in these financial services businesses. The net carrying amounts of our goodwill as of January 1, 2002 and December 31, 2002 reported in net intangible assets in our balance sheets, and the changes in the net carrying amounts of goodwill for the year ended December 31, 2002 for each of our segments are as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other	Total
			(In millions)			
Balances as of January 1, 2002	$413	$61	$393	$ 89	$249	$1,205
Impairments	—	—	—	(44)	—	(44)
Other changes	—	1	9	—	(5)	5
Balances as of December 31, 2002	$413	$62	$402	$ 45	$244	$1,166

Our other intangible assets consist of customer lists, our general partnership interest in El Paso Energy Partners, L.P. and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life excluding our excess investment in our general partnership interest in El Paso Energy Partners which has been determined to have an indefinite life. The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of December 31:

	2002	2001
	(In millions)	
Intangible assets subject to amortization	$ 52	$ 59
Accumulated amortization	(29)	(20)
	23	39
Intangible assets not subject to amortization	181	181
	$204	$220

Amortization expense of our intangible assets that were subject to amortization was $9 million for the year ended December 31, 2002. For the year ended December 31, 2001, amortization of all intangible assets, including goodwill, was $55 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense is approximately $2 million for each of the next five years. These amounts may vary as a result of future acquisitions, dispositions and any recorded impairments.

The following table presents our income from continuing operations before extraordinary items and the cumulative effect of accounting changes, net income and earnings per common share for the years ended December 31, 2001 and 2000, as if goodwill and other indefinite-lived intangibles had not been amortized during those periods, compared with those amounts reported for the year ended December 31, 2002:

	Year Ended December 31,		
	2002	2001	2000
	(In millions, except per common share amounts)		
Reported income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes[1]	$(1,289)	$ 72	$1,237
Amortization of goodwill and indefinite-lived intangibles	—	35	44
Adjusted income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(1,289)	$ 107	$1,281
Net income (loss):			
Reported net income (loss)	$(1,467)	$ 93	$1,306
Amortization of goodwill and indefinite-lived intangibles	—	35	44
Adjusted net income (loss)	$(1,467)	$ 128	$1,350
Basic earnings per common share:			
Reported net income (loss)	$ (2.62)	$0.18	$ 2.64
Amortization of goodwill and indefinite-lived intangibles	—	0.07	0.09
Adjusted net income (loss)	$ (2.62)	$0.25	$ 2.73
Diluted earnings per common share:			
Reported net income (loss)	$ (2.62)	$0.18	$ 2.57
Amortization of goodwill and indefinite-lived intangibles	—	0.07	0.09
Adjusted net income (loss)	$ (2.62)	$0.25	$ 2.66

(1) Amounts include the reclassification of the results of our coal business as discontinued operations.

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

We compare the benefits earned, or the accumulated benefit obligation, to the plan's fair value of assets on an annual basis. To the extent the plan's accumulated benefit obligation exceeds the fair value of plan assets, we record a minimum pension liability in our balance sheet equal to the difference in these two amounts. We do not adjust this minimum liability if it is less than the liability already accrued for the plan. If this difference is greater than the pension liability recorded on our balance sheet, however, we record an additional liability and an amount to other comprehensive loss, net of income taxes, on our financial statements.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. Our revenue recognition policies by segment are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services and sales under gas sales contracts. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period. For interruptible or volumetric based services, we record revenues when we complete the delivery of natural gas to the agreed upon delivery point and when natural gas is injected or withdrawn from the storage facility. Revenues under natural gas sales contracts are recognized when physical deliveries of commodities are made at the agreed upon delivery point. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract or tariff. We are subject to FERC regulations and, as a result, revenues we collect may possibly be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We have established reserves for these potential refunds.

Production revenues. Our Production segment's revenues are derived principally through physical sales of natural gas, oil and natural gas liquids produced. Revenues from sales of these products are recorded upon the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. When actual natural gas sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. Costs associated with the transportation and delivery of production are included in cost of sales.

Field Services revenues. Our Field Services segment derives revenues principally from gathering, transportation and processing services and through the sale of commodities that are retained from providing these services. There are two general types of service: fee-based and make-whole. For fee-based services we recognize revenues at the time service is rendered based upon the volume of gas gathered, treated or processed at the contracted fee. For make-whole services, our fee consists of retainage of natural gas liquids and other by-products that are a result of processing, and we recognize revenues on these services at the time we sell these products, which generally coincides with when we provide the service.

Merchant Energy revenues. Merchant Energy derives revenues from a number of sources including physical sales of natural gas, power and petroleum, and petroleum products. Revenues on these physical sales are recognized based on the volumes delivered and the contracted or market price and are recognized at the time the commodity is delivered to the specified delivery point. Revenues from commodities sold as part of Merchant Energy's energy trading division are reflected net of the cost of these sales. The energy trading division of Merchant Energy also enters into derivative transactions which are recorded at their fair value. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities.*

Corporate. Revenue producing activities in our corporate segment consist principally of revenues from our telecommunications business. We recognize revenues for our metro transport, collocation and cross-connect services in the month that the services are actually used by the customer.

Environmental Costs and Other Contingencies

We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal or regulatory guidelines dictate otherwise. Estimates of our liabilities are based on 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. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage or government sponsored programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

We engage in price risk management activities to manage market risks associated with commodities we purchase and sell, interest rates and foreign currency exchange rates. These price risk management activities include trading activities that we enter into with the objective of generating profits or from exposure to shifts or changes in market prices, non-trading activities related to our power investment, generation and power contract restructuring activities, and other non-trading activities that involve hedging the market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions of each of our business segments. Our trading and non-trading price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded futures contracts that involve cash settlements;
- forward contracts that involve cash settlements or physical delivery of a commodity;
- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the counter options.

We account for our trading and non-trading derivative instruments under SFAS No. 133, *Accounting for Derivatives and Hedging Activities.* Under SFAS No. 133, all derivatives are reflected in our balance sheet at their fair value as price risk management activities. We classify our price risk management activities as either current or non-current assets or liabilities based on our overall position by counterparty and their anticipated settlement date. Cash inflows and outflows associated with the settlement of our price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported separately from price risk management activities in our balance sheet as trade receivables and payables. The accounting for revenues and expenses associated with our price risk management activities varies based on whether those activities are trading activities or non-trading activities. See Note 13 for a further description of our price risk management activities.

During 2002, we adopted DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed-price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one fuel supply contract upon adoption of these new rules, and we recorded a gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement for our proportionate share of this gain.

During 2002, we also adopted the provisions of EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. Prior to EITF Issue No. 02-3, we accounted for our non-derivative trading instruments, such as contracts for transportation and storage capacity and physical natural gas inventory and exchanges that were actively traded as part of our trading business, at their fair value under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk*

Management Activities. EITF Issue No. 02-3 rescinded EITF Issue No. 98-10 and reached two general conclusions:

- Contracts which do not meet the definition of a derivative under SFAS No. 133 should not be marked to fair market value, and
- Revenues and costs associated with trading activities should be shown net in the income statement, whether or not they are physically settled.

As a result of our adoption of EITF Issue No. 02-3, we adjusted the carrying value of our non-derivative trading instruments (principally transportation and storage capacity contracts) to zero and now account for them using the accrual basis of accounting. We also adjusted the physical natural gas inventory and exchanges used in our trading business to their actual cost (which was lower than market) and expected settlement amounts and reclassified these amounts to inventory and accounts receivable and payable on our balance sheet. The adoption of EITF Issue No. 02-3 had the following impacts on our financial statements:

- The elimination of the mark-to-market value for contracts that do not meet the definition of a derivative ($225 million), which is reported as a cumulative effect of change in accounting principle;
- An adjustment of the carrying value of our natural gas inventory to its weighted average cost and the value of exchanges to their expected settlement price assuming they had been accounted for under that basis since their acquisition ($118 million), which is reported as a cumulative effect of change in accounting principle; and
- A balance sheet reclassification of natural gas inventory and exchanges from price risk management assets to inventory and accounts receivable and payable ($254 million).

In total, we recorded a cumulative effect of an accounting change in our income statement of $343 million ($222 million net of income taxes) from the adoption of EITF Issue No. 02-3. We also began to report our trading activity on a net basis (revenues net of the expenses of the physically settled purchases) as a component of revenues effective July 1, 2002. We applied this guidance to all prior periods, which had no impact on previously reported net income or stockholders' equity. Revenues and costs for periods prior to the adoption of EITF Issue No. 02-3 are revised as follows:

	Year Ended December 31,	
	2001	2000
	(In millions)	
Gross operating revenues	$ 57,138	$ 48,639
Costs reclassified	(43,489)	(29,368)
Net operating revenues reported in the income statements	$ 13,649	$ 19,271

Income Taxes

We report current income taxes based on our taxable income, and we provide for deferred income taxes to reflect estimated future tax payments and receipts. Deferred taxes represent the tax impacts 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 on 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 recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

We maintain a tax accrual policy to record both regular and alternative minimum taxes for companies included in our consolidated federal income tax return. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal income tax, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated return. We pay all federal income taxes directly to the IRS and, under a separate tax billing agreement, we may bill or refund our subsidiaries for their portion of these income tax payments.

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component of interest expense. During 2002, the net currency gain recorded in operating income was less than $1 million. Net currency losses recorded to operating income in 2001 and 2000 were $13 million and less than $1 million. We incurred currency losses in 2002 of approximately $95 million on our euro-denominated debt which were included in interest expense. Gains and losses were minimal on foreign denominated debt in 2001 and 2000. The U.S. dollar is the functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and included as a separate component of comprehensive income and stockholders' equity. The cumulative currency translation loss recorded in accumulated other comprehensive income was $115 million and $97 million at December 31, 2002 and 2001. Revenues and expenses are translated at average exchange rates prevailing during the year.

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, 2002, and 2001, were approximately 1.7 million shares and 5.5 million shares of common stock held in a trust under our deferred compensation programs.

Stock-Based Compensation

We apply the provisions of Accounting Principles Board Opinion No. 25 (APB No. 25) and its related interpretations to account for our stock-based compensation plans. We have both fixed and variable compensation plans, and we account for these plans using fixed and variable accounting as appropriate. Compensation expense for variable plans, including restricted stock grants, is measured using the market price of the stock on the date the number of shares in the grant becomes determinable. This measured expense is amortized into income over the period of service in which the grant is earned. Our stock options are issued under a fixed plan. 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. Had we accounted for our stock option grants using SFAS No. 123 *Accounting for Stock-Based Compensation,* rather than the provisions of APB No. 25, the income and per share impacts of stock-based compensation on our financial statements of stock-based compensation would have been different. The following shows the impact on net income and earnings per share had we applied the provisions of SFAS No. 123.

	Year Ended December 31,		
	2002	2001	2000
	(In millions, except per common share amounts)		
Net income (loss), as reported	$(1,467)	$ 93	$1,306
Deduct: Total stock-based employee compensation determined under fair value based method for all awards, net of related tax effects	143	157	43
Pro forma net income (loss)	$(1,610)	$ (64)	$1,263
Earnings (loss) per share:			
Basic, as reported	$ (2.62)	$ 0.18	$ 2.64
Basic, pro forma	$ (2.88)	$(0.13)	$ 2.56
Diluted, as reported	$ (2.62)	$ 0.18	$ 2.57
Diluted, pro forma	$ (2.88)	$(0.12)	$ 2.48

Accounting for Debt Extinguishments

We apply the provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections,* to account for debt extinguishments. Under SFAS No. 145, we are required to evaluate any gains or losses incurred when we retire debt early to determine whether they are extraordinary in nature or whether they should be included as ordinary income from continuing operations in the income statement. In the third quarter of 2002, we retired debt totaling $94 million, which resulted in a gain of $21 million. Because we believe that we will continue to retire debt in the near term, we reported these gains as income from continuing operations, as part of other income.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2002, there were a number of accounting standards and interpretations that had been issued but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Accounting for Asset Retirement Obligations. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement requires companies to record a liability for the estimated retirement and removal costs of long-lived assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We expect that we will record a charge as a cumulative effect of accounting change of approximately $23 million, net of income taxes, upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of $184 million and non-current retirement liabilities of $214 million on January 1, 2003. Our liability relates primarily to our obligations to plug abandoned wells in our Production and Pipelines segments over the next one to 101 years.

Accounting for Costs Associated with Exit or Disposal Activities. In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Guarantees. In November 2002, the FASB issued FASB Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* This interpretation requires that companies record a liability for all guarantees issued after January 31, 2003, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included these required disclosures in Note 20.

Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003 for all variable interest entities created before January 31, 2003. We have financial interests in several entities that we anticipate will be considered variable interest entities. They fall into three categories:

- Operating leases with residual value guarantees;
- Consolidated subsidiaries with preferred interests held by third party financial investors; and
- Equity investments.

Operating leases with residual value guarantees. We have two operating leases where we provide a guarantee to the lessor for the residual value of the facilities that we lease. These leases are for the following facilities:

- The Lakeside Technology Center, a telecommunications facility that provides collocation and cross-connect services; and
- A facility at our Aruba refinery.

We believe we will consolidate the lessors under these arrangements on July 1, 2003 because (i) the equity investment by the third party investors (which are banks), is less than 10 percent of the total capitalization of the company that leases the facilities to us, and (ii) because we guarantee a significant portion of the funds that were borrowed by the lessor to buy the facilities from us. When we consolidate the lessors of these facilities, the assets owned by the lessors and the debt that supports the assets will be consolidated in our financial statements. In addition, these assets, once consolidated, will be subject to impairment testing under SFAS No. 144. Based on our preliminary analysis, we believe the impact on our financial statements will be as follows (in millions):

Increase in total assets	$625
Less: Impairments	113
Net increase in assets	$512
Increase in long-term debt	$625

Consolidated subsidiaries with preferred interests held by third party investors. We currently have interests in and consolidate several entities in which third party investors hold preferred interests. The preferred interests held by the third party investors are reflected in our balance sheet as preferred securities in consolidated subsidiaries. The third party investors are capitalized with three percent equity, which is held by banks in these arrangements, and 97 percent debt. We believe we would consolidate these third party investors under these arrangements because (i) the equity investment in these third party investors is less than the specified 10 percent of total capitalization of the investors and (ii) the rights of the third party investors to expected residual returns from these arrangements is limited. When we consolidate these third party investors, the minority interest that is currently classified as preferred securities in consolidated subsidiaries will be classified as long-term debt. Clydesdale and Coastal Securities Company Limited are our consolidated subsidiaries that will be impacted by this standard. If we had not redeemed our Trinity River financing arrangement in March 2003, it would also have been impacted by this standard. We believe the impact on our financial statements will be (in millions):

Decrease in preferred securities of consolidated subsidiaries	$1,050
Increase in long-term debt	$1,050

For a further discussion of the consolidated subsidiaries potentially impacted by this pronouncement, see Note 19.

Equity investments. We have equity investments in Chaparral and Gemstone. These power investments involve a disproportionate allocation of income and losses relative to the capital investments that are made by the equity holders. To determine whether we would be required to consolidate these entities, we evaluated the expected future losses of the entities, and how those losses would be allocated to the owners. If we determined that we would be exposed to the greatest level of the expected future losses, we would consolidate those entities. Based on our analysis, we determined it is likely that we will consolidate these investments because of our guarantee of the debt of the third party investors which exposes us to a greater level of loss. However, we anticipate that we will consolidate these investments prior to the effective date of FIN No. 46 because we expect to purchase the third party investors' interests in these investments. For a discussion of the equity investments we hold, see Note 26.

2. Western Energy Settlement

On March 20, 2003, we entered into an agreement in principle (Western Energy Settlement) with various public and private claimants, including the states of California, Washington, Oregon and Nevada, to resolve the principal litigation, claims and regulatory proceedings against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the settlement. See Note 20 for a discussion of this matter.

The Western Energy Settlement resulted in a charge in the fourth quarter of 2002 of $899 million before tax and approximately $650 million after tax. These amounts represent the present value of the components of the settlement discounted at 10 percent. The settlement will include an initial payment of cash, the issuance of our common stock and the payment of cash and delivery of natural gas over a period of 20 years. The settlement will become payable beginning with the execution of a definitive settlement agreement. Components of the settlement were allocated among our Pipelines, Merchant Energy and Corporate segments, based on the nature of the component and the segment's ability to perform under the agreement. The components are as follows:

- a cash payment of $100 million to the settling parties;
- a $2 million cash payment from our officer bonus pool;
- the issuance of approximately 26.4 million shares of our common stock;
- the delivery to the California border of $45 million worth of natural gas annually for 20 years, beginning in 2004;
- the reduction of the pricing of our long-term power supply contracts with the California Department of Water Resources of $125 million over the remaining term of those contracts, which run through the end of 2005;
- payment to the settling parties of $22 million a year in cash (or, at our option, in cash and stock) for 20 years;
- for a period of five years, EPNG will make available at its California delivery points, 3,290 MMcf/d of capacity on a primary delivery point basis;
- for a period of five years, our affiliate will be subject to restrictions in subscribing new capacity on the EPNG system; and

• no admission of wrongdoing.

The settlement is subject to review and approval by state courts and the FERC.

The total obligation for the settlement is reflected in our balance sheet at $0.9 billion, which represents the notional amount of approximately $1.7 billion, less a discount (at a rate of 10 percent) of approximately $0.8 billion. The components of the obligation for the settlement are as follows:

	(In millions)
Total Western Energy Settlement	$1,690
Discount at 10 percent	(791)
Net present value at settlement	899
Less: Current portion of obligation	100
Non-current obligation for Western Energy Settlement	$ 799

The discount will be amortized to interest expense annually at an amount based on a constant rate of interest (10 percent) applied to the declining obligation balance. This amortization is expected to be approximately $47 million for 2003, after income taxes.

3. Mergers and Divestitures

Coastal Merger

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal's 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. In the merger, we issued approximately 271 million shares of our common stock, including 4 million shares in exchange for Coastal stock options. The following table presents the revenues and net income for the previously separate companies and the combined amounts presented in these audited combined financial statements for the year ended December 31, 2000 (in millions). Several adjustments were made to conform the accounting presentation of this financial information.

Revenues	
El Paso	$21,950
Coastal	18,014
Conforming reclassifications(1)	8,951
Combined(2)	$48,915
Extraordinary items, net of income taxes	
El Paso	$ 70
Coastal	—
Combined	$ 70
Net income	
El Paso	$ 652
Coastal	654
Combined	$ 1,306

(1) Conforming reclassifications primarily include a gross-up of revenues associated with Coastal's physical petroleum marketing and trading activities to be consistent with our method of reporting these revenues.

(2) Combined revenues do not take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. The impact of EITF Issue No. 02-3 on reported 2000 revenues was a reduction of these combined amounts by $29.4 billion. These amounts also do not consider the reclassification of $276 million of revenues related to coal mining properties, which were reclassified in our financial statements as discontinued operations during 2002. See Notes 1 and 10 for further discussion of these matters.

Divestitures

During 2002 and into 2003, we have completed or announced a number of asset sales in order to rationalize our business and address liquidity issues and changing market conditions. These sales occurred in all of our business segments as follows:

Segment	Proceeds	Pretax Gain (Loss)	Significant Assets and Investments Sold
	(In millions)		
Completed in 2002			
Pipelines	$ 303	$ 4	Natural gas and oil properties located in Texas, Kansas and Oklahoma and their related contracts
			12.3 percent equity interest in Alliance Pipeline and related assets
			Typhoon natural gas pipeline[3]
Production	1,297	—[1]	Natural gas and oil properties located in:
			East and south Texas
			Colorado
			Southeast Texas
			Utah
			Western Canada
Field Services	1,513	196	Texas and New Mexico midstream assets[2]
			Dragon Trail processing plant
			San Juan Basin gathering, treating and processing assets[3]
			14.4 percent equity interest in Aux Sable NGL plant
			Gathering facilities located in Utah
			50 percent interest in Blacks Fork facility
Merchant Energy	161	(1)	50 percent equity interest in petroleum products terminal
			NGL pipelines and fractionation facilities[3]
			14.4 percent equity interest in Alliance Canada Marketing L.P.
			40 percent equity interest in Samalayuca Power II power project in Mexico
			Typhoon oil pipeline [3]
Corporate and Other	57	—	Coal reserves and properties in West Virginia, Virginia and Kentucky[4]
	$3,331	$199	

(1) We did not recognize gains or losses on these completed sales of natural gas and oil properties because individually they did not significantly alter the relationship between capitalized costs and proved reserves at the time they were sold.

(2) Proceeds of $735 million consisted of $539 million in cash, common units of El Paso Energy Partners with a fair value of $6 million and the partnership's interest in the Prince tension leg platform including its nine percent overriding royalty interest in the Prince production field with a combined fair value of $190 million.

(3) Proceeds from these sales of $766 million consisted of $416 million in cash and $350 million of Series C units, a new non-voting class of the limited partnership interest in El Paso Energy Partners.

(4) During 2002, we recorded impairment charges of $185 million since the carrying value was higher than our estimated net sales proceeds. These properties are presented in our financial statements as discontinued operations. See Note 10 for further discussion.

Segment	Proceeds	Pretax Gain (Loss)	Significant Assets and Investments Sold
	(In millions)		
Announced or Completed in 2003 (amounts are estimates)[1]			
Pipelines	$ 43	$ (1)	Panhandle gathering system located in Texas
			2.1 percent equity interest in Alliance pipeline and related assets
Production	687	—[2]	Natural gas and oil properties located in western Canada, Oklahoma, New Mexico and offshore.
Field Services	35	—	Gathering systems located in Wyoming
Merchant Energy	813	69	50 percent equity interest in CE Generation L.L.C. power investment (including the rights to a 50 percent interest in a geothermal development project)[3]
			Mt. Carmel power plant
			Kladno power project
			Corpus Christi refinery
			Florida petroleum terminals and tug and barge operations[4]
			Petroleum asphalt operations
			Enerplus Global Energy Management Company
Corporate and Other	89	(8)	Remaining coal reserves and properties in West Virginia, Virginia and Kentucky[5]
			Aircraft
	$ 1,667	$ 60	

(1) Sales that have been announced, but not completed, are subject to customary regulatory approvals and other conditions.

(2) We do not anticipate recognizing gains or losses on these sales of natural gas and oil properties because individually they will not significantly alter the relationship between capitalized costs and proved reserves at the time they are sold.

(3) During 2002, we recorded impairment charges of $74 million resulting from an expected sale of our ownership interests.

(4) The amount includes $25 million receivable.

(5) Proceeds of $59 million consisted of $35 million in cash and $24 million in notes receivable.

In December 2002, we reclassified several of Field Services' small gathering systems located in Wyoming and Merchant Energy's Florida petroleum terminals and tug and barge operations to assets held for sale. We also classified our petroleum asphalt operations and lease crude business as held for sale. The total assets being sold had a net book value in property, plant and equipment of approximately $134 million. We reclassified these assets as other current assets as of December 31, 2002, since we plan to sell them in the next twelve months.

Under a Federal Trade Commission order, as a result of our January 2001 merger with Coastal, we sold our Midwestern Gas Transmission system, our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems, and our investments in the Empire State and Iroquois pipeline systems. For the year ended December 31, 2001, net proceeds from these sales were approximately $279 million, and we recognized extraordinary net gains of approximately $26 million, net of income taxes of approximately $27 million.

During 2000, we sold East Tennessee Natural Gas Company, Sea Robin Pipeline Company and our one-third interest in Destin Pipeline Company to comply with an FTC order related to our merger with Sonat. Net proceeds from these sales were approximately $616 million, and we recognized an extraordinary gain of $89 million, net of income taxes of $59 million. In December 2000, we sold our interest in Oasis Pipeline Company to comply with an FTC order. We incurred a loss on this transaction of approximately $19 million, net of income taxes of $9 million. We recorded the gains and losses on these sales as extraordinary items in our income statement.

In February 2003, we announced we would exit non-core businesses, including substantially all of our petroleum business (except our Aruba refinery). Since making this announcement, we have been identifying potential buyers for our petroleum assets. At this time, we cannot determine the amount of gain or loss, if any, that will be incurred. We will continue to evaluate whether these assets will be treated for accounting purposes as assets held for sale or possibly as discontinued operations.

4. Restructuring and Merger-Related Costs

During each of the three years ended December 31, we incurred restructuring costs, merger-related costs and asset impairment charges as follows:

	2002	2001	2000
		(In millions)	
Restructuring costs	$81	$ —	$—
Merger-related costs	—	1,520	93
	$81	$1,520	$93

Restructuring Costs

Our restructuring costs were incurred in connection with organizational restructurings in connection with our balance sheet and liquidity enhancement actions taken in 2002. By segment, these charges were as follows:

	Pipelines	Field Services	Merchant Energy	Corporate and Other	Total
			(In millions)		
Employee severance, retention and transition costs	$ 1	$ 1	$28	$11	$41
Transaction costs	—	—	—	40	40
	$ 1	$ 1	$28	$51	$81

In December 2001, we announced a plan to strengthen our balance sheet, reduce costs and focus our activities on our core natural gas businesses. During 2002, we completed an employee restructuring across all of our operating segments which resulted in a reduction of approximately 772 full-time positions through terminations. As a result of these actions, we incurred $41 million of employee severance and termination costs, $30 million of which had been paid as of December 31, 2002. We also incurred and paid fees of $40 million to eliminate stock price and credit rating triggers related to our Chaparral and Gemstone investments.

Merger-Related Costs

During the years ended 2001 and 2000, we incurred merger-related costs in connection with our merger with Coastal completed in January 2001 as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other	Total
			(In millions)			
2001						
Employee severance, retention and transition costs	$ 83	$ 7	$ 5	$18	$ 725	$ 838
Transaction costs	—	—	—	—	70	70
Business and operational integration costs	178	17	—	—	188	383
Other	30	23	41	26	109	229
	$291	$47	$46	$44	$1,092	$1,520
2000						
Employee severance, retention and transition costs	$ —	$—	$—	$—	$ 31	31
Transaction costs	—	—	—	—	60	60
Other	—	—	—	—	2	2
	$ —	$—	$—	$—	$ 93	$ 93

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 our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers 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.

Employee severance, retention and transition costs for 2001 were approximately $838 million, which included pension and post-retirement benefits of $214 million which were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid. Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares.

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. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments. Total charges in 2001 were $383 million, of which $153 million related to a charge resulting from a mark-to-market loss on an energy-related contract for transportation capacity on the Alliance Pipeline. Prior to the merger, this contract was managed by Coastal's Production segment. Following the merger, it was determined that this contract should be managed in our trading group, consistently with our other energy-related pipeline capacity contracts. As a result, it was transferred to Merchant Energy. The charge reflects the estimated realizable value of the contract as an energy-related trading contract. Our integration costs also include incremental fees under software and seismic license agreements of $15 million which were recorded in our Production segment. Additional integration costs included approximately $222 million in estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado, $13 million of which was recorded as an impairment of assets and was incurred in both our Pipelines and Corporate segments. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with Coastal and other miscellaneous charges. As part of the FTC order related to our merger with Coastal, El Paso Energy Partners, L.P. was required to sell its 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 $25 million. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by El Paso Energy Partners. We expensed these items at the same time we committed to pay them.

5. Gain (Loss) on Long-Lived Assets

Gain (loss) on long-lived assets consist of realized gains and losses on sales of long-lived assets and impairments of long-lived assets. During each of the years ended December 31, our gains (losses) on long-lived assets were as follows:

	2002	2001	2000
		(In millions)	
Realized gain (loss)	$ 267	$ (5)	$ 29
Asset impairments	(549)	(178)	(24)
Gain (loss) on long-lived assets	$(282)	$(183)	$ 5

Realized Gain (Loss)

Our realized gain (loss) on sales of long-lived assets for the years ended December 31, 2002, 2001 and 2000, were $267 million, $(5) million and $29 million. Our 2002 gains were primarily a result of asset sales to enhance our liquidity related to the sales of our San Juan gathering assets, our Natural Buttes and Ouray gathering system, our Dragon Trail processing plant and our Texas and New Mexico midstream assets in our Field Services segment. See Note 3 for a further discussion of these divestitures. Our 2001 losses related to miscellaneous asset sales across all our segments and our 2000 gains related to the sales of a portion of our Montreal paraxylene plant in our Merchant Energy segment and non-regulated pipeline assets in our Pipelines segment.

Asset Impairments

During the years ended December 31, we incurred asset impairment charges in our business segments as follows:

Segment and Asset Description	Amount (In millions)	Cause of Impairment
2002		
Production		
Intangible asset	$ 4	Sale of underlying properties
Total Production	4	
Field Services		
North Louisiana gathering facilities	66	Decision to sell assets
Total Field Services	66	
Merchant Energy		
MTBE chemical processing plant	91	MTBE was banned in our largest market. Decision to eliminate future capital spending to refit plant for alternative fuel uses
Power turbines	162	Scaled down capital spending in new power facilities and weak economic conditions in the power sector
Goodwill on investment management business	44	Decision to reduce future capital funding for this business
Solarc project	14	Decision to discontinue future capital investment
Total Merchant Energy	311	
Corporate and Other		
Telecommunications dark fiber	168	Change in business strategy to focus on Texas metro business and weak industry conditions for long-haul fiber
Total Corporate and Other	168	
Total 2002 asset impairments	$549	
2001		
Pipelines		
Renaissance Center leasehold improvements	$ 9	Relocation of Detroit headquarters
Supply Link projects	7	Decision following the Coastal merger not to pursue these projects
Other projects	6	Decision following the Coastal merger not to pursue these projects.
Total Pipelines	22	
Production		
Australian and Indonesian assets	16	Decision following the Coastal merger not to drill in these areas
Total Production	16	
Merchant Energy		
Oyster Creek chemical refining facility	37	Refinery shut down following Coastal merger
Kansas refining operations	35	Refinery closed as a result of sale of retail outlets in the midwest
Capitalized development costs	20	Decision not to pursue projects following Coastal merger
Other merchant assets	24	Change in strategy and business decisions following merger
Corpus Christi refinery	8	Lease of Corpus Christi refinery to Valero Energy Corporation
Total Merchant Energy	124	
Corporate and Other		
Telecommunications assets	12	Weak economic conditions and outlook in the telecommunication business
Miscellaneous corporate assets	4	Relocation of Detroit headquarters
Corporate and Other	16	
Total 2001 asset impairments	$178	
2000		
Field Services		
Needle Mountain processing facility	$ 11	Ongoing weak economic outlook in the markets served by this plant
Total Field Services	11	
Merchant Energy		
Florida and other refining assets	13	Decision not to pursue development on these projects
Total Merchant Energy	13	
Total 2000 asset impairments	$ 24	

Our impairment charges were based on reducing the carrying value of these assets to their estimated fair value. Fair value was determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset).

6. Accounting Changes

Changes in Accounting Principle

During the year ended December 31, 2002, we recorded the cumulative effects in income of changes in accounting principles as follows (in millions):

	Before-tax	After-tax
Adoption of EITF Issue No. 02-3	$(343)	$(222)
Adoption of SFAS No. 141 and 142	154	154
Adoption of DIG Issue No. C-16	23	14
Total	$(166)	$ (54)

For a discussion of each of the accounting principles we adopted during 2002, See Note 1.

Changes in Accounting Estimate

Included in our operation and maintenance costs for the year ended December 31, 2001, were approximately $316 million in costs related to changes in accounting estimates which consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $37 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. The change in our estimated environmental remediation liabilities was due to a number of events, including $109 million resulting from the sale of a majority of our retail gas stations, $31 million related to our closure of our Gulf Coast Chemical and Midwest refining operations, $10 million associated with the lease of our Corpus Christi refinery to Valero, and $82 million associated with conforming Coastal's methods of environmental identification, assessment and remediation strategies and processes to our historical practices following our merger with Coastal. This accounted for the remainder of the change in estimated obligations. The change in estimate of our legal obligations was a result of a review process to assess our legal exposures, strategies and plans following the merger with Coastal. Finally, the charge related to our spare parts inventories was primarily the result of several events that occurred as part of and following our merger with Coastal, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery whereby a portion of the plant was rebuilt following the fire rendering many of these parts unusable. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. Our changes in estimates are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001, by approximately $215 million.

7. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects.

For the year ended December 31, 2002, we recorded ceiling test charges of $269 million, of which $33 million was charged during the first quarter, $234 million was charged during the second quarter, and $2 million was charged during the fourth quarter. The write-down includes $226 million for our Canadian full cost pool, $24 million for our Turkish full cost pool, $10 million for our Brazilian full cost pool and $9 million for other international production operations, primarily in Australia. The charge for the Canadian full cost pool primarily resulted from a low daily posted price for natural gas at June 30, 2002, which was approximately $1.43 per MMBtu.

For the year ended December 31, 2001, we recorded ceiling test charges of $135 million, including $87 million for our Canadian full cost pool, $28 million for our Brazilian full cost pool, and $20 million for other international production operations, primarily in Turkey. Our 2001 charges were based on the daily posted natural gas and oil prices as of November 1, 2001, adjusted for oilfield or natural gas gathering hub and wellhead price differences as appropriate. Had we computed the third quarter 2001 ceiling test charges based upon the daily posted natural gas and oil prices as of September 30, 2001, we would have incurred a ceiling test charge of $275 million. This amount would have included $227 million for our Canadian full cost pool and $48 million for our Brazilian full cost pool and other international production operations, primarily in Turkey.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in determining our ceiling test charges, and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our third quarter 2001 ceiling test charges, we would have incurred a third quarter charge of $576 million at September 30, 2001, relating to our domestic full cost pool. The charges for our international cost pools would not have materially changed since we do not significantly hedge our international production activities.

8. Other Income and Other Expenses

Following are the components of other income and other expenses for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
Other Income			
Interest income	$ 84	$109	$ 84
Favorable resolution of non-operating contingent obligations	38	6	5
Gain on early retirement of debt	21	—	1
Rental income	18	35	20
Development, management and administrative services fees on power projects	24	110	40
Income from retail operations	—	7	15
Gains on non-trading derivatives	8	5	14
Property losses and insurance	28	61	5
Other	27	63	50
Total	$248	$396	$234
Other Expenses			
Impairment on cost basis investment(1)	$ 56	$ 66	$ —
Donations and contributions	1	14	17
Foreign currency losses	5	13	2
Penalty and legal expenses	7	8	4
Amortization expense	1	10	8
Miscellaneous balancing adjustments	17	14	—
Other	22	11	26
Total	$109	$136	$ 57

(1) We impaired our investment in our Costanera power plant in 2002 and various telecommunication investments in 2001.

9. Income Taxes

Pretax income (loss) from continuing operations before extraordinary items and cumulative effect of accounting change are composed of the following for each of the three years ended December 31:

	2002	2001	2000
	(In millions)		
United States	$(1,624)	$178	$1,527
Foreign	(160)	78	249
	$(1,784)	$256	$1,776

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

	2002	2001	2000
	(In millions)		
Current			
Federal	$ (38)	$(32)	$(78)
State	27	(14)	(11)
Foreign	36	30	16
	25	(16)	(73)
Deferred			
Federal	(441)	271	566
State	13	(18)	46
Foreign	(92)	(53)	—
	(520)	200	612
Total income tax expense (benefit)	$(495)	$184	$539

Our tax expense (benefit), included in income (loss) from continuing operations 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 for each of the three years ended December 31:

	2002	2001	2000
	(In millions)		
Tax expense (benefit) at the statutory federal rate of 35%	$(624)	$ 90	$622
Increase (decrease)			
State income tax, net of federal income tax benefit	26	(21)	22
Earnings from unconsolidated affiliates where we anticipate receiving dividends	2	(20)	(28)
Non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities	(3)	115	12
Foreign income taxed at different rates	117	14	(60)
Deferred credit on loss carryover	—	(7)	(18)
Preferred stock dividends of a subsidiary	10	12	13
Non-conventional fuel tax credit	(11)	(6)	(9)
Depreciation, depletion and amortization	1	23	(14)
Other	(13)	(16)	(1)
Income tax expense (benefit)	$(495)	$184	$539
Effective tax rate	28%	72%	30%

The following are the components of our net deferred tax liability related to continuing operations as of December 31:

	2002	2001
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$4,769	$4,319
Investments in unconsolidated affiliates	695	706
Price risk management activities	—	564
Regulatory and other assets	575	884
Total deferred tax liability	6,039	6,473
Deferred tax assets		
Net operating loss and tax credit carryovers		
U.S. Federal	1,080	1,051
State	104	86
Foreign	22	—
Western Energy Settlement	328	—
Price risk management activities	308	—
Environmental liability	201	220
Other liabilities	707	890
Valuation allowance	(37)	(3)
Total deferred tax asset	2,713	2,244
Net deferred tax liability	$3,326	$4,229

At December 31, 2002, 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 $1,309 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 these 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 $15 million in 2002, $31 million in 2001 and $60 million in 2000. These benefits are included in additional paid-in capital in our balance sheets.

As of December 31, 2002, we have charitable contribution carryovers of $27 million for which the carryover periods end as follows: $1 million in 2003, $22 million in 2004 and $4 million in 2006; alternative minimum tax credits of $281 million that carryover indefinitely; and $2 million of general business credit carryovers for which the carryover periods end at various times in the years 2009 through 2021. The table below presents the details of our federal net operating loss carryover periods.

	Carryover Period				
	2003	2004 - 2010	2011 - 2015	2016 - 2021	Total
			(In millions)		
Federal net operating loss	$5	$65	$287	$1,892	$2,249

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.

As of December 31, 2002, we had $1,129 million of state net operating loss carryovers. These carryovers will expire in varying amounts over the period from 2003 to 2021. We also had $73 million of foreign net operating loss carryovers that carryover indefinitely.

We recorded a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2002, approximately $14 million of the valuation allowance relates to our foreign deferred tax assets for ceiling test charges, $22 million relates to our foreign net operating loss carryovers and $1 million relates to our U.S. Federal general business credit carryovers. As of December 31, 2001, approximately $1 million of the valuation allowance relates to U.S. Federal net operating loss carryovers of an acquired company and $2 million relates to U.S. Federal general business credit carryovers.

10. Discontinued Operations

In June 2002, our Board of Directors authorized the sale of our coal mining operations. These operations, which have historically been included in our Merchant Energy segment, consist of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our Board of Directors, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process in the second and third quarters of 2002. Because this carrying value was higher than our estimated net sales proceeds, we recorded impairment charges of $148 million in the second quarter of 2002 and $37 million in the third quarter of 2002.

In December 2002, we sold substantially all of our reserves and properties in West Virginia, Virginia and Kentucky to an affiliate of Natural Resources Partners, L.P. for $57 million in cash. In January 2003, we sold our remaining coal operations, which consists of mining operations, businesses, properties and reserves in Kentucky, West Virginia and Virginia, to subsidiaries of Alpha Natural Resources, LLC, an affiliate of First Reserve Corporation, for $59 million which includes $35 million in cash and $24 million in notes receivable.

Our coal mining operations have been classified as discontinued operations in our financial statements for all periods presented. In addition, we reclassified all of the assets and liabilities of our remaining coal mining operations as of December 31, 2002 to other current assets and liabilities. The summarized financial results of discontinued operations for each of the three years ended December 31, are as follows:

	2002	2001	2000
		(In millions)	
Operating Results:			
Revenues	$ 309	$ 277	$ 276
Costs and expenses	(327)	(286)	(270)
Asset impairments	(185)	—	(8)
Other income, net	6	2	1
Loss before income taxes	(197)	(7)	(1)
Income tax benefit	73	2	—
Loss from discontinued operations, net of income taxes	$(124)	$ (5)	$ (1)

	December 31, 2002	December 31, 2001
	(In millions)	
Financial Position Data:		
Assets of discontinued operations		
Accounts receivable	$ 29	$ 35
Inventory	14	11
Property, plant and equipment, net	46	301
Other	17	5
Total assets	$106	$352
Liabilities of discontinued operations		
Accounts payable and other	$ 25	$ 37
Environmental remediation reserve	15	—
Total liabilities	$ 40	$ 37

11. Earnings Per Share

We calculated basic and diluted earnings per share amounts as follows for each of the three years ended December 31:

	2002		2001		2000	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)					
Income (loss) from continuing operations	$(1,289)	$(1,289)	$ 72	$ 72	$1,237	$1,237
Preferred stock dividend	—	—	—	—	—	—
Income (loss) from continuing operations available to common stockholders	(1,289)	(1,289)	72	72	1,237	1,237
Trust preferred securities[1]	—	—	—	—	—	10
Convertible debentures[1]	—	—	—	—	—	—
Adjusted income from continuing operations	(1,289)	(1,289)	72	72	1,237	1,247
Discontinued operations, net of income taxes	(124)	(124)	(5)	(5)	(1)	(1)
Extraordinary items, net of income taxes	—	—	26	26	70	70
Cumulative effect of accounting change, net of income taxes	(54)	(54)	—	—	—	—
Adjusted net income (loss)	$(1,467)	$(1,467)	$ 93	$ 93	$1,306	$1,316
Average common shares outstanding	560	560	505	505	494	494
Effect of dilutive securities						
Restricted stock	—	—	—	1	—	—
Stock options[2]	—	—	—	5	—	7
FELINE PRIDES[sm]	—	—	—	5	—	3
Preferred stock	—	—	—	—	—	1
Trust preferred securities[1][2]	—	—	—	—	—	8
Equity security units	—	—	—	—	—	—
Convertible debentures[1][2]	—	—	—	—	—	—
Average common shares outstanding	560	560	505	516	494	513
Earnings per common share						
Adjusted (loss) income from continuing operations	$ (2.30)	$ (2.30)	$ 0.14	$ 0.14	$ 2.50	$ 2.43
Discontinued operations, net of income taxes	(0.22)	(0.22)	(0.01)	(0.01)	—	—
Extraordinary items, net of income taxes	—	—	0.05	0.05	0.14	0.14
Cumulative effect of accounting change, net of income taxes	(0.10)	(0.10)	—	—	—	—
Adjusted net income (loss)	$ (2.62)	$ (2.62)	$ 0.18	$ 0.18	$ 2.64	$ 2.57

(1) Due to its antidilutive effect on earnings per share, approximately 7 million shares related to our convertible debentures were excluded from 2001 dilutive shares, and approximately 8 million shares related to our trust preferred securities were excluded in 2001.

(2) Due to its antidilutive effect on earnings per share, approximately 1 million shares related to our stock options, approximately 8 million shares related to our convertible debentures and approximately 8 million shares related to our trust preferred securities were excluded in 2002.

12. Financial Instruments

Following are the carrying amounts and estimated fair values of our financial instruments as of December 31:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments	$ 44	$ 44	$ 28	$ 28
Long-term debt and other obligations, including current maturities	16,681	12,268	14,615	14,089
Notes payable to unconsolidated affiliates	390	380	872	896
Company obligated preferred securities of subsidiaries	625	278	925	1,048
Trading derivative price risk management activities	(59)	(59)	240[(1)]	240[(1)]
Non-trading commodity-based price risk management activities	459	459	459	459
Non-trading foreign currency and interest rate swaps	22	22	(33)	(33)

(1) Does not include $1,055 million of non-derivative contracts as of December 31, 2001 including transportation capacity, tolling agreements and natural gas in storage held for trading purposes since these do not constitute financial instruments.

As of December 31, 2002 and 2001, 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.

13. Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of December 31:

	2002	2001
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[(1)]	$ (59)	$1,295
Non-trading contracts		
Derivatives designated as hedges	(500)	459
Other derivatives	959	—
Total energy contracts	400	1,754
Interest rate and foreign currency contracts	22	(33)
Net assets from price risk management activities[(2)]	$ 422	$1,721

(1) Trading contracts are those that are entered into for purposes of generating a profit or benefiting from movements in market prices.

(2) Net assets from price risk management activities include current and non-current assets and current and non-current liabilities from price risk management activities on the balance sheet.

Included in other derivatives as of December 31, 2002, are $968 million of derivative contracts related to the power restructuring activities of our consolidated subsidiaries. Of this amount, $878 million relates to a power restructuring that occurred during the first quarter of 2002 at our Eagle Point Cogeneration power plant, and $90 million relates to a power restructuring at our Capitol District Energy Center Cogeneration Associates plant. The remaining balance in other derivatives, an unrealized loss of $9 million, relates to derivative positions that no longer qualify as cash flow hedges under SFAS No. 133 because they were designated as hedges of anticipated future production on natural gas and oil properties that were sold during 2002.

Trading Activities and Contracts. Our trading activities include the services we provide in the energy sector that we enter into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities. In the fourth quarter of 2002, we announced our intent to exit our trading activities and to pursue an orderly liquidation of our trading price risk management activities through 2004.

The derivative instruments we use in our trading activities are either traded on active exchanges such as the New York Mercantile Exchange or are valued using exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. Because of our actions to limit our trading activities and exit the trading business, our accessibility to reliable forward market data for purposes of estimating fair value was significantly limited in late 2002. As a result, we obtained valuation assistance from a third party valuation specialist in determining the fair value of our trading and non-trading price risk management activities as of December 31, 2002. Based upon the specialist's input, our estimates of fair value are based upon price curves derived from actual prices observed in the market, pricing information supplied by the specialist and independent pricing sources and models that rely on this forward pricing information. These estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable time under present market conditions, modeling risk, credit risk of our counterparties and operational risks, as needed. We have discontinued applying our ten-year liquidity valuation allowance that we had instituted during the first quarter of 2002 in circumstances where there was uncertainty related to our forward prices in less liquid markets. To the extent that the forward market data received from the third party specialist indicates value beyond ten years, we now include that value in the fair value of our trading and non-trading price risk management activities.

We have reflected our trading portfolio at estimated fair value which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. However, the value we ultimately receive in settlement of our trading activities may be less than our fair value estimates. As disclosed previously, we are actively liquidating our trading portfolio, which includes approximately 40,000 transactions as of December 31, 2002. We believe the net realizable value of our trading portfolio may be less than its currently estimated fair value. Our belief is based on recent transactions completed at values below estimated fair value and bids received on transactions that were also below their fair value. Additionally, because of the adoption of EITF Issue No. 02-3, a portion of the transactions that we plan to liquidate are accounted for under the accrual method and are not recorded in our balance sheet. Should we have to pay counterparties to assume these transactions, future losses will result.

Until we complete our exit of the energy trading business, we will continue to serve a diverse group of customers that require a wide variety of financial structures, products and terms. This diversity requires us to manage, on a portfolio basis, the resulting market risks inherent in our trading price risk management activities 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 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 in both our trading and non-trading price risk management activities 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 following table presents a summary of our counterparties in which we have net asset exposure from our trading and non-trading price risk management activities:

	Net Asset Exposure from Price Risk Management Activities as of December 31, 2002		
	Investment Grade[1]	Below Investment Grade[1][2]	Total
		(In millions)	
Counterparty			
Energy marketers	$ 485	$212	$ 697
Financial institutions	16	—	16
Natural gas and oil producers	30	4	34
Natural gas and electric utilities	1,275	86	1,361
Industrials	—	1	1
Municipalities	49	—	49
Net asset exposure from price risk management activities[3]	$1,855	$303	$2,158

	Net Asset Exposure from Price Risk Management Activities as of December 31, 2001		
	Investment Grade[1]	Below Investment Grade[1][2]	Total
		(In millions)	
Counterparty			
Energy marketers	$1,330	$419	$1,749
Financial institutions	161	—	161
Natural gas and oil producers	106	11	117
Natural gas and electric utilities	1,033	82	1,115
Industrials	13	18	31
Municipalities	231	—	231
Net asset exposure from price risk management activities[3]	$2,874	$530	$3,404

(1) "Investment Grade" and "Below Investment Grade" are primarily determined using publicly available credit ratings, or if a counterparty is not publicly rated, a minimum implied credit rating through internal credit analysis. "Investment Grade" includes counterparties with a minimum Standard & Poor's rating of BBB– or Moody's rating of Baa3. "Below Investment Grade" includes counterparties with a credit rating that do not meet the criteria of "Investment Grade".

(2) As of December 31, 2002, we required collateral, which encompasses margins and standby letters of credit for $170 million of the $303 million, or 56 percent, from counterparties included in "Below Investment Grade".

(3) Net asset exposure from price risk management activities have been prepared by netting assets against liabilities on counterparties where we have a contractual right to offset. The positions netted include both current and non-current amounts. As a result, these amounts do not agree to our total assets from price risk management activities in our balance sheet. In addition, in 2001, the counterparty total does not include assets for natural gas in storage and marketable securities held for trading purposes of $196 million.

In the tables above, we had one customer that comprised greater than 5 percent of our net asset exposure from price risk management activities as of December 31, 2002 and 2001. This customer as of December 31, 2002, Public Service Electric and Gas Company, comprised approximately 41 percent of the net asset exposure from price risk management activities by counterparty and was considered an investment grade company as of December 31, 2002. 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.

Non-trading Activities — Derivatives Designated as Hedges.

We use derivative financial instruments to hedge the impact of our market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions related to our natural gas and oil production, refining, natural gas transmission, power generation, financing and international business activities. We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or firm commitment. On the date that we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Changes in derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments.

As required by SFAS No. 133, we formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge or if we decide to discontinue the hedging relationship.

The fair value of our hedging instruments reflects our best estimate and is based on exchange or over-the-counter quotations when they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $1,280 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as hedging instruments. The majority of the initial charge related to hedging cash flows from anticipated sales of natural gas for 2001 and 2002. During the year ended December 31, 2001, $1,063 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the year. A discussion of our hedging activities is as follows:

Fair Value Hedges. We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the years ended December 31, 2002 and 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of December 31, 2002 and 2001, the value of cash flow hedges included in accumulated other comprehensive income was a net unrealized loss of $377 million and a net unrealized gain of $256 million, net of income taxes. We estimate that unrealized losses of $124 million, net of income taxes, will be reclassified from accumulated other comprehensive income during 2003. Reclassifications occur upon physical delivery of the hedge commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 10 years; however, most of our cash flow hedges expire within the next 24 months. We had a net liability from price risk management activities of $500 million as of December 31, 2002 and a net asset from price risk management activities of $459 million as of December 31, 2001 associated with our cash flow hedges. This net change of $959 million during 2002 resulted from net settlements of $222 million during 2002 and a decrease in fair value of $737 million in our cash flow hedge positions during 2002.

Our accumulated other comprehensive income as of December 31, 2002 and 2001 also includes a loss of $65 million and $23 million, net of income taxes, representing our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges. Included in this loss is a $7 million loss that we estimate will be reclassified from accumulated other comprehensive income during 2003. The maximum term of these cash flow hedges is two years, excluding hedges related to interest rates on variable debt.

For the years ended December 31, 2002 and 2001, we recognized a net loss of $15 million and a net gain of $3 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

In May 2002, we announced a plan to reduce the volumes of natural gas that we have hedged for our Production segment, and we removed the hedging designation on derivatives that had a fair value loss of $105 million at December 31, 2002. This amount, net of income taxes of $38 million, is reflected in accumulated other comprehensive income and will be reclassified to income as the original hedged transactions are settled through 2004. Of the net loss of $67 million in accumulated other comprehensive income, we estimate that unrealized losses of $42 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

Foreign Currency Hedges. In our international activities, we have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollar. In 2002 and 2001, we used currency swaps to effectively convert the fixed amounts of foreign currency due under foreign currency denominated debt to U.S. dollar amounts. In December 2002, we decided to reduce the volumes of foreign currency exchange risk that we have hedged for our debt, and we removed the hedging designation on derivatives that had a net fair value loss of $1 million at December 31, 2002. Of this amount, a $14 million loss, net of income taxes of $5 million, is reflected in accumulated other comprehensive income and a $8 million gain is reflected in the unamortized discount on long-term debt. These amounts will be reclassified to income as the interest and principal on the debt are settled through 2009. Of the net loss of $9 million included in accumulated other comprehensive income and $8 million deferred gain included in long-term debt, we estimate that unrealized losses of $1 million and unrealized gains of $2 million related to these derivatives will be reclassified to income over the next twelve months.

Non-trading Activities — Power Restructuring Activities.

Our Merchant Energy segment's power restructuring activities involved amending or terminating a power plant's existing power purchase contract to eliminate the requirement that the plant provide power from its own generation to the regulated utility and replacing that requirement with the ability to provide power to the utility from the wholesale power market. In conjunction with our power restructuring activities, we generally entered into new market-based contracts with third parties to provide the power to the utility from the wholesale power market, which effectively "locks in" our margin on the restructuring transaction as the difference between the contracted rate in the restructured contract and the wholesale market rates at the time.

Prior to a restructuring, the power plant and its related power purchase contract are generally accounted for at their historical cost, which is either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to the restructuring are, in most cases, accounted for on an accrual basis as power is generated and sold to the utility.

Following a restructuring, the accounting treatment for the power purchase agreement must change if the restructured contract meets the definition of a derivative and is therefore required to be marked to its fair value under SFAS No. 133. In addition, since the power plant no longer has the exclusive right to provide power under the original, dedicated power purchase contract, it operates as a peaking merchant plant, generating power only when it is economical to do so. Because of this significant change in its use, the fair value of the plant may be less than its historical value. These changes may also require us to terminate or amend any related fuel supply and steam agreements, and enter into other third party and intercompany contracts such as transportation agreements, associated with the operations of the facility.

Our power restructuring activities had the following effects to our financial statements:

- The restructured contract (if it meets the definition of a derivative) is shown as an asset from price risk management activities in our balance sheet.

- The difference between the fair value of the restructured contract and the carrying value of the original contract is shown as operating revenues in our income statement. Any subsequent changes in this fair value are also recorded in operating revenues.

- The new third party wholesale power supply and other contracts are recorded at their fair value as assets or liabilities from price risk management activities in our balance sheet. Any subsequent changes in the fair value are also recorded in operating revenues.

- The carrying value of the underlying power plant and any related intangible assets are evaluated for impairment and, if required, are written down to their fair value as a merchant power plant, which is recorded as operating expenses in our income statement.

- Any contract termination fees and closing costs are also recorded as operating expenses in our income statement.

- As we purchase power under the wholesale power supply contracts, we record the cost of the power we purchase as operating expenses in our income statement.

- As we sell that power to the utility under the restructured contract, we record the amounts received under the contract as operating revenues.

We classify our restructured contracts as non-trading price risk management activities in our disclosures. We classify our third party and other contracts as trading price risk management activities because they are actively managed by our trading operations.

We have historically conducted the majority of our power restructuring activities through our unconsolidated affiliate, Chaparral, and therefore our share of the revenues and expenses of these activities is recognized through earnings from unconsolidated affiliates.

In 2002 we completed a power restructuring on our Eagle Point Cogeneration facility, which we consolidate, and applied the accounting described above to that transaction. Power restructuring activities can also involve contract terminations that result in a cash payment by the utility to cancel the underlying power contract, as in our Mount Carmel transaction. We also employed the principles of our power restructuring business in reaching a settlement in 2002 of the dispute under our Nejapa power contract which included a cash payment to us. We recorded these payments as operating revenues. As of and for the year ended

December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements (in millions):

	Assets from Price Risk Management Activities	Liabilities from Price Risk Management Activities	Property, Plant and Equipment and Intangible Assets	Operating Revenues	Operating Expenses	Increase (Decrease) in Minority Interest
Initial gain on restructured contracts	$978			$1,118		$ 172
Writedown of power plants and intangibles and other fees			$(352)		$476	(109)
Change in value of restructured contracts during 2002	8			(96)		(20)
Change in value of third party wholesale power supply contracts . .		$18		(18)		(3)
Purchase of power under power supply contracts					47	(11)
Sale of power under restructured contracts				111		28
Total	$986	$18	$(352)	$1,115	$523	$ 57

The fair value of the derivatives related to our power restructuring activities is determined based on the expected cash receipts and payments under the contracts using future power prices compared to the contractual prices under these contracts. We discount these cash flows at an interest rate commensurate with the term of each contract and the credit risk of each contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in fair values that can be realized. Future power prices are based on the forward pricing curve of the appropriate power delivery and receipt points in the applicable power market. This forward pricing curve is derived from available market data and pricing information supplied by a third party. The timing of cash receipts and payments are based on the expected timing of power delivered under these contracts. The fair value of our derivatives may change each period based on changes in actual and projected market prices, fluctuations in the credit ratings of our counterparties, significant changes in interest rates, and changes to the assumed timing of deliveries.

As a result of credit downgrades, our decision to exit the energy trading business, and disruptions in the capital markets, it is unlikely we will pursue additional power restructurings in the near term.

14. Inventory

Our inventory consisted of the following at December 31:

	2002	2001
	(In millions)	
Current		
Refined products, crude oil and chemicals	$ 602	$ 577
Materials and supplies and other	208	197
NGL and natural gas in storage	78	41
Total current inventory	888	815
Non-current		
Dark fiber	5	152
Turbines	222	231
Total non-current inventory	227	383
Total inventory	$1,115	$1,198

Effective October 1, 2002, we adopted the provisions of EITF Issue No. 02-3. EITF Issue No. 02-3 requires, among other things, that we account for all inventory used in our trading activities at the lower of its cost or fair value, rather than using mark-to-market accounting as was previously allowed under EITF Issue No. 98-10. Effective October 1, 2002, we adjusted the fair value of these inventories in our balance sheet to their historical cost using a weighted average cost methodology and reclassified those amounts from price risk management activities to inventory as natural gas in storage. See Note 1 for a further discussion of the impact of EITF No. 02-3.

15. Regulatory Assets and Liabilities

Our regulatory assets are included in other current and non-current regulatory assets, and regulatory liabilities are included in other current and non-current regulatory liabilities. These balances are presented in our balance sheets on a gross basis. Below are the details of our regulatory assets and liabilities, which represent our regulated interstate systems that apply the provisions of SFAS No. 71, at December 31:

Description	2002	2001	Remaining Recovery Period
	(In millions)		(Years)
Current regulatory assets			
Other[1]	$ 3	$ 2	1
Non-current regulatory assets			
Grossed-up deferred taxes on capitalized funds used during construction[2]	59	59	11-15
Under-collected state tax	8	11	2-3
Postretirement benefits[1][3]	26	28	10
Unamortized net loss on reacquired debt[1]	29	31	15-19
Other[1]	7	23	1-10
Total non-current regulatory assets	129	152	
Total regulatory assets	$132	$154	
Current regulatory liabilities			
Cashout imbalance settlement[1]	$ 8	$ 13	N/A
Non-current regulatory liabilities			
Environmental liability[1]	55	46	3
Excess deferred federal taxes	14	21	2-3
Property and plant depreciation	22	24	various
Plant regulatory liability[1]	12	7	N/A
Postretirement benefits[1]	9	7	N/A
Total non-current regulatory liabilities	112	105	
Total regulatory liabilities	$120	$118	

(1) These amounts are not included in a rate base on which we earn a current return.

(2) These amounts are recovered over the remaining depreciable lives of property, plant and equipment.

(3) The amount is to be recovered in future rate proceeding.

16. Other Assets and Liabilities

Below is the detail of our other current and non-current assets and liabilities on our balance sheets as of December 31:

	2002	2001
	(In millions)	
Other current assets		
Deferred income taxes	$ 221	$ 159
Prepaid assets	136	157
Restricted cash	124	17
Discontinued operations	106	36
Assets held for sale	134	—
Other	117	178
Total	$ 838	$ 547
Other non-current assets		
Pension assets	$ 866	$ 775
Notes receivable from affiliates	466	346
Turbine inventory	222	231
Restricted cash	212	75
Unamortized debt expenses	182	148
Other investments	167	97
Regulatory assets	129	152
Notes receivable	52	57
Insurance receivables	49	18
Dark fiber inventory	5	152
Discontinued operations	—	316
Other	219	129
Total	$2,569	$2,496
Other current liabilities		
Accrued interest	$ 327	$ 231
Accrued taxes, other than income	167	191
Environmental, legal and rate reserves	153	97
Dividends payable	130	108
Accrued liabilities	102	126
Deposits	66	13
Discontinued operations	40	34
Planned major maintenance accrual	40	36
Deferred risk-sharing revenue	32	32
Postretirement benefits	35	46
Income taxes	19	146
Other	174	194
Total	$1,285	$1,254

	2002	2001
	(In millions)	
Other non-current liabilities		
Environmental and legal reserves	$ 494	$ 681
Postretirement and employment benefits	322	358
Deferred gain on sale of assets to El Paso Energy Partners	268	10
Obligations under swap agreement	255	393
Other deferred credits	154	233
Accrued lease obligations	124	85
Unearned revenues	8	125
Regulatory liabilities	112	105
Deferred compensation	105	237
Insurance reserves	104	109
Other	73	27
Total	$2,019	$2,363

17. Property, Plant and Equipment

At December 31, 2002 and 2001, we had approximately $1,865 million and $2,330 million of construction work in progress included in our property, plant and equipment.

In June 2001, we entered into a 20-year lease agreement related to our Corpus Christi refinery and related assets with Valero. Under the lease, Valero pays us a quarterly amount that increases after the second year of the lease. For the years ended December 31, 2002 and 2001, we recorded $19 million and $11 million in lease income related to this lease. In February 2003, Valero exercised its option to purchase the plant and related assets for $289 million in cash. We recorded a gain of $8 million.

As of December 31, 2002, TGP, EPNG and ANR have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $5 billion and accumulated depreciation was approximately $1 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during 2002 was approximately $71 million. The adoption of SFAS No. 142 did not impact these amounts since they were included as part of our property, plant and equipment, rather than as goodwill.

We have goodwill recorded as a result of the acquisitions of ANR and CIG. This goodwill was $723 million at December 31, 2002, and $310 million of accumulated amortization. In conjunction with adoption of SFAS 142, on January 1, 2002, we ceased our amortization of this goodwill and performed the required impairment tests on this goodwill. No impairment of this goodwill was indicated as of January 1, 2002 and December 31, 2002.

18. Debt, Other Financing Obligations and Other Credit Facilities

At December 31, 2002, our weighted average interest rate on our commercial paper and short-term credit facilities was 2.69%, and at December 31, 2001, it was 3.2%. We had the following short-term borrowings and other financing obligations, at December 31:

	2002	2001
	(In millions)	
Short-term credit facilities	$1,500	$ 111
Commercial paper	—	1,265
Current maturities of long-term debt and other financing obligations	575	1,799
Notes payable	—	64
	$2,075	$3,239

Credit Facilities

We have historically used commercial paper programs to manage our short-term cash requirements. Under our programs we can borrow up to $3 billion through a combination of individual corporate, TGP and EPNG commercial paper programs of $1 billion each. However, as a result of our credit downgrade, we are not currently issuing commercial paper to meet our liquidity needs.

In May 2002, we renewed our existing 364-day, $3 billion revolving credit and competitive advance facility. EPNG and TGP are also designated borrowers under this new facility and, as such, are jointly and severally liable for any amounts outstanding. This facility matures in May 2003 and provides that amounts outstanding on that date are not due until May 2004. We also maintain a 3-year, $1 billion, revolving credit and competitive advance facility under which we can conduct short-term borrowings and other commercial credit transactions. In June 2002, we amended this facility to permit us to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003, and El Paso CGP (formerly Coastal), EPNG and TGP, our subsidiaries, are designated borrowers under the facility and, as such, are jointly and severally liable for any amounts outstanding. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of December 31, 2002, borrowings under these facilities have a rate of LIBOR plus 1.00% plus a 0.25% utilization fee. At December 31, 2002, we had $1.5 billion outstanding under the $3 billion facility and issued approximately $456 million letters of credit under the $1 billion facility. In February 2003, we borrowed $500 million under the $1 billion facility.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which 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.

Restrictive Covenants

We and our subsidiaries have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross-payment default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries.

Under our revolving credit facilities, the significant debt covenants and cross defaults are:

(a) the ratio of consolidated debt and guarantees to capitalization (excluding certain project financing and securitization programs and other miscellaneous items as defined in the agreement) cannot exceed 70 percent;

(b) the consolidated debt and guarantees (other than excluded items) of our subsidiaries cannot exceed the greater of $600 million or 10 percent of our consolidated net worth;

(c) we or our principal subsidiaries cannot permit liens on the equity interest in our principal subsidiaries or create liens on assets material to our consolidated operations securing debt and guarantees (other than excluded items) exceeding the greater of $300 million or 10 percent of our consolidated net worth, subject to certain permitted exceptions; and

(d) the occurrence of an event of default for any non-payment of principal, interest or premium with respect to debt (other than excluded items) in an aggregate principal amount of $200 million or more; or the occurrence of any other event of default with respect to such debt that results in the acceleration thereof.

We were in compliance with the above covenants as of the date of this filing, including our ratio of debt to capitalization (as defined under our agreements), which was 63.2 percent at year end. At December 31, 2002, we had $1.5 billion outstanding under the $3 billion facility and issued approximately $456 million letters of credit under the $1 billion facility. In February 2003, we borrowed $500 million under the $1 billion facility.

We have also issued various guarantees securing financial obligations of our subsidiaries and unconsolidated affiliates with similar covenants as in the above credit facilities.

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision. El Paso CGP's net worth at December 31, 2002, was $4.3 billion.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million of cross-acceleration provisions.

Our long-term debt and other financing obligations outstanding consisted of the following at December 31:

	2002	2001
	(In millions)	
Long-term debt		
El Paso Corporation		
Senior notes, 5.75% through 7.125%, due 2006 through 2009	$ 1,597	$ 989
Equity Security Units, 6.14% due 2007	575	—
Notes, 6.625% through 7.875%, due 2005 through 2018	2,021	1,600
Medium-term notes, 7.002% through 9.25%, due 2004 through 2031	2,812	1,600
Zero coupon convertible debentures due 2021	848	812
El Paso Tennessee Pipeline		
Notes, 7.25% through 10.0%, due 2008 through 2025	51	51
Debentures, 6.5% through 7.875%, due 2002 through 2005	—	12
Tennessee Gas Pipeline		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
Notes, 8.375%, due 2032	240	—
El Paso Natural Gas		
Notes, 6.75% through 8.375%, due 2002 through 2032	500	415
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
Southern Natural Gas		
Notes, 6.125% through 8.625%, due 2002 through 2032	800	700
Field Services[1]		
Medium term notes, 7.41% through 9.25% due 2002 through 2012	—	164
El Paso CGP		
Senior notes, 6.2% through 8.125%, due 2002 through 2010	1,305	1,565
Floating rate senior notes, due 2002 through 2003	200	600
Senior debentures, 6.375% through 10.75%, due 2003 through 2037	1,497	1,497
FELINE PRIDES, 6.625%, due 2004	—	460
Valero lease financing loan due 2004[2]	240	240
Power		
Non-recourse senior notes, 7.75% and 7.944%, due 2008 and 2016	915	—
Non-recourse notes 8.5%, due 2005	126	—
El Paso Production Company		
Floating rate notes, due 2005 and 2006	200	200
ANR Pipeline		
Debentures, 7.0% through 9.625%, due 2021 through 2025	500	500
Notes, 13.75% due 2010	13	—
Colorado Interstate Gas		
Debentures, 6.85% through 10.0%, due 2005 and 2037	280	280
Other	145	483
	16,711	14,014
Other Financing Obligations		
Crude oil prepayments[3]	—	500
Natural gas production payment	—	215
Other	17	—
	17	715
Subtotal	16,728	14,729
Less:		
Unamortized discount on long-term debt	47	39
Current maturities	575	1,799
Total long-term and other financing obligations, less current maturities	$16,106	$12,891

(1) The company holding these notes was merged into El Paso Corporation in 2002.

(2) Collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery. The Valero loan was repaid in February 2003.

(3) Secured by our agreement to deliver a fixed quantity of crude oil to a specified delivery point in the future. As of December 31, 2002, all of the crude oil prepayment obligations had been paid.

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2003	$ 575
2004	586
2005	610
2006	1,234
2007	1,133
Thereafter	12,590
Total long-term debt and other financing obligations, including current maturities	$16,728

Our zero coupon convertible debentures have a maturity value of $1.8 billion, are due 2021 and have a yield to maturity of 4%. The holders can cause us to repurchase these at their option in years 2006, 2011 and 2016, at which time we can elect to settle in cash or common stock. 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 is equal to a conversion price of $94.604 per share of our common stock.

In June 2002, we issued 51.8 million shares of our common stock at a public offering price of $19.95 per share. Net proceeds from the offering were approximately $1 billion.

In June 2002, we issued 11.5 million, 9% equity security units. Equity security units consist of two securities: i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86% and that requires its holder to buy our common stock to be settled on August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14% beginning August 16, 2002. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders obligation to purchase shares of our common stock under the purchase contracts.

When the purchase contracts are settled in 2005, we will issue common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 24 million shares and up to a maximum of 28.8 million shares on the settlement date, depending on our average stock price. We recorded approximately $43 million of other non-current liabilities to reflect the present value of the quarterly contract adjustment payments that we are required to make on these units at an annual rate of 2.86% of the stated amount of $50 per purchase contract with an offsetting reduction in additional paid-in capital. The quarterly contract adjustment payments are allocated between the liability recognized at the date of issuance and additional paid-in capital based on a constant rate over the term of the purchase contracts.

Fees and expenses incurred in connection with the equity security units offering were allocated between the senior notes and the purchase contracts based on their respective fair values on the issuance date. The amount allocated to the senior notes is recognized as interest expense over the term of the senior notes. The amount allocated to the purchase contracts is recorded as additional paid-in capital.

In July 2002, Utility Contract Funding issued $829 million of 7.944% senior secured notes due in 2016. This financing is non-recourse to other El Paso companies, as it is independently supported only by the cash flows and contracts of Utility Contract Funding including obligations of Public Service Electric and Gas under a restructured power contract and of Morgan Stanley under a power supply agreement. In connection with the credit enhancement provided by Morgan Stanley's participation, we paid them $36 million in consideration for entering into the supply agreement.

In July 2002, we entered into two cross-currency swap transactions which effectively hedged €400 million of our euro currency risk on our €500 million Euro-denominated debt. In the first transaction, €250 million of our 7.125% fixed rate was swapped for $252.5 million of floating rate debt at a rate of the six-month LIBOR plus a spread of 2.195%. A second transaction swapped €150 million of our 7.125% fixed rate euro based debt for $151.5 million, 7.08% fixed dollar based debt. In December 2002, we terminated cross-currency swap transactions which had effectively hedged €675 million euro currency risk. Our €275 million exposure remains hedged at an effective rate of 6.59% through its maturity in 2006.

In August 2002, we issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES^{SM} program. In return for the issuance of the stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004 that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

In January 2003, we retired various debt obligations of approximately $47 million. In February 2003, El Paso CGP retired $240 million 3.07% long-term debt related to the Valero lease.

In March 2003, our subsidiaries, Southern Natural Gas and ANR Pipeline issued senior notes in concurrent offerings totaling $700 million:

- Southern Natural Gas Company issued $400 million of 8⅞% senior unsecured notes due 2010, raising net proceeds of $385 million. Proceeds from the offering were used, in part, to repay intercompany obligations of $290 million and Southern Natural Gas retained $95 million of net proceeds to fund its future capital expenditures.

- ANR Pipeline Company issued $300 million of 8⅞% senior unsecured notes due 2010, raising net proceeds of $288 million. ANR used $263 million of cash proceeds from the offering to reduce existing intercompany payables. ANR also retained $25 million to fund its future capital expenditures.

In March 2003, we closed a $1.2 billion two-year term loan and used the proceeds to retire the approximately $913 million net balance of the Trinity River financing. Trinity River (also known as Red River) was formed in 1999 to invest in capital projects and other assets. The new $1.2 billion loan has scheduled payments of $300 million in June 2004, $300 million in September 2004, and the $600 million balance in March 2005. The loan facility is collateralized by a direct pledge of natural gas and oil properties that were previously in the Trinity River financing. The loan facility carries a floating interest rate of LIBOR plus 4.25%. The floating interest rate can be based on a LIBOR rate of no less than 3.50%. Additionally, the loan facility requires us to pay a facility fee equal to 2% per annum on the average daily aggregate outstanding principal amount of the loan. The natural gas and oil properties that collateralize this financing agreement have reserves of approximately 2.3 Tcfe.

Available Capacity Under Shelf Registration Statements

In April 2001, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, medium term notes, or trust securities. At December 31, 2001, we had approximately $920 million remaining from this shelf registration statement under which we issued additional securities in January 2002, fully utilizing the remaining capacity.

In February 2002, we filed a new shelf registration statement with the SEC that allows us to issue up to $3 billion in securities. Under this registration statement, we can issue a combination of debt, equity and other instruments, including trust preferred securities of two wholly owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities. As of December 31, 2002, we had $818 million remaining capacity under this shelf registration statement.

As of December 31, 2002, TGP and SNG had no available capacity under shelf registration statements on file with the SEC.

19. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into financing transactions that have been accomplished through the sale of preferred interests in consolidated subsidiaries. Total amounts outstanding under these programs at December 31, 2002 and 2001, were as follows (in millions):

	2002	2001
Consolidated trusts[1]	$ 625	$ 925
Trinity River[2]	980	980
Clydesdale	950	1,000
Preferred stock of subsidiaries	400	465
Gemstone	300	300
Consolidated partnership	—	285
	$3,255	$3,955

(1) The consolidated trusts are composed of Capital Trust I, Coastal Finance I and Capital Trust IV. In November 2002, we repurchased all of the preferred securities for Capital Trust IV for $300 million plus accrued and unpaid dividends.

(2) This preferred interest was redeemed in March 2003 with the proceeds from a $1.2 billion debt facility with scheduled maturities of $300 million in June 2004, $300 million in September 2004 and the $600 million in March 2005.

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I, a wholly owned subsidiary, which issued 6.5 million of 4¾% trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4¾% convertible subordinated debentures we issued due 2028, their sole asset. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay the obligations on Trust I's preferred securities. We provide a full and unconditional guarantee of Trust I's preferred securities. Distributions paid on the preferred securities are included as return on preferred interests of consolidated subsidiaries 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). As of December 31, 2002, we had approximately 6.5 million Trust I preferred securities outstanding.

Coastal Finance I. Coastal Finance I is an indirect wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I holds subordinated debt securities issued by our wholly owned subsidiary, El Paso CGP, that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. Coastal Finance I's only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I's preferred securities. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003, or earlier if various events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. El Paso CGP provides a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available. El Paso has no obligation to provide funds to Coastal Finance I for the payment of or redemption of the preferred securities outside of our obligation to pay interest and principal on the subordinated debt securities.

Capital Trust IV. In May 2000, we formed El Paso Energy Capital Trust IV, a wholly owned subsidiary which issued $300 million of preferred securities to an affiliate of Banc of America. These preferred securities paid cash distributions at a floating rate equal to the three-month LIBOR plus 75 basis points. As of December 31, 2001, the floating rate was 2.83%. In November 2002, we purchased all of the preferred securities of Trust IV for $300 million plus accrued and unpaid dividends and terminated obligations to issue equity securities under this agreement.

Trinity River (also known as Red River). During 1999, we formed a series of companies that we refer to as Trinity River. Trinity River is a subsidiary that was formed to provide financing to invest in various capital projects and other assets. Red River Investors, L.L.C., an entity owned by three investors, West LB, Stonehurst and Ambac, raised funds from a consortium of banks that contributed cash of $980 million into Trinity River during 1999 in exchange for the preferred securities. Red River Investors is entitled to an adjustable preferred return derived from Trinity River's net income. The preferred interest, which has limited voting rights, was collateralized by a combination of notes payable from us and various El Paso entities, including our Mojave Pipeline Company, Bear Creek Storage Company, various natural gas and oil properties and 5.75 million of our El Paso Energy Partners common units. The assets, liabilities and operations of Trinity River are included in our financial statements and we account for the investor's preferred interest in our consolidated subsidiary as preferred interests of consolidated subsidiaries in our balance sheet and the preferred return as return on preferred securities of subsidiary in our income statement. As a result of El Paso's and its subsidiaries' credit rating downgrades by both Moody's and Standard & Poor's, restrictions resulted on our use of excess cash generated by these operating businesses for purposes other than their own operating needs or to redeem the preferred interests of Trinity River. In the first quarter of 2003, we redeemed the preferred interests of Trinity River, eliminating these cash restrictions.

Clydesdale (also known as Mustang). During 2000, we formed a series of companies that we refer to as Clydesdale. Clydesdale is a subsidiary that was formed to provide financing to invest in various capital projects and other assets. Mustang Investors LLC, an entity owned by two investors West LB and Ambac, raised funds from a consortium of banks, which contributed cash of $1 billion into Clydesdale in exchange for preferred securities. Mustang is entitled to an adjustable preferred return derived from Clydesdale's net income. The preferred interest, which has limited voting rights, is collateralized by a combination of notes payable from us, a production payment from us, various natural gas and oil properties and various companies, including our ownership in Colorado Interstate Gas Company. We have the option to acquire Mustang Investors' interest in Clydesdale at any time prior to June 2006. If we do not exercise this option or if the agreement is not extended, we could be required to liquidate the assets supporting this transaction. The assets, liabilities, and operations of Clydesdale are included in our financial statements and we account for the investor's preferred interest in our consolidated subsidiary as preferred interests of consolidated subsidiaries in our balance sheet and the preferred return as return on preferred stock of consolidated subsidiaries in our income statement. In July 2002, we completed the amendments to the Clydesdale agreements to remove the rating trigger that could have required us to liquidate the assets supporting the transaction in the event we were downgraded to below investment grade by both Standard & Poor's and Moody's. As a result of El Paso's and its subsidiaries credit rating downgrades by both Moody's and Standard & Poor's, restrictions resulted on use of excess cash generated by these assets for purpose other than their own operating needs or to redeem the preferred interests of Clydesdale. A portion of these funds were used to redeem the preferred interests of Clydesdale, including $50 million as of December 31, 2002, and an additional $189 million in February and March 2003. These payments are reflected as reductions of preferred interests of consolidated subsidiaries. Quarterly payments will be made to reduce the minority interests.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co., our subsidiary, issued 6 million shares of publicly registered 8.25% cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at the option of El Paso Tennessee, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time after January 2002. During the three years ended December 31, 2002, dividends of approximately $25 million were paid each year on the preferred stock.

Coastal Securities Company Preferred Stock. In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million to Cannon Investors Trust, which is an entity comprised of a consortium of banks. Quarterly cash dividends are being paid on the preferred stock at a rate based on LIBOR plus a margin of 2.11% based on the long-term unsecured debt rating of our subsidiary, El Paso CGP. The holders of the preferred securities have a right to reset the dividend rate on December 20, 2003 and every seven years thereafter. If the new rate is not acceptable to the preferred holders, they have a right to require us to redeem the preferred securities. The preferred holders are also entitled to participating dividends based on refining margins of our Aruba refinery. Coastal Securities may redeem the preferred stock for cash at the liquidation price of $100 million plus accrued and unpaid dividends.

El Paso Oil & Gas Resources Preferred Units. In 1999, El Paso Oil & Gas Resources Company, L.P. (formerly Coastal Oil & Gas Resources, Inc.), our wholly owned subsidiary, issued 50,000 units of preferred units for $50 million to UAGC, Inc., a subsidiary of Rabobank International. The preferred shareholders were entitled to quarterly cash dividends at a rate based on LIBOR. In July 2002, we repurchased the entire 50,000 units for $50 million plus accrued and unpaid dividends.

Coastal Limited Ventures Preferred Stock. In 1999, Coastal Limited Ventures, Inc., our wholly owned subsidiary, issued 150,000 shares of preferred stock for $15 million to JP Morgan Chase Bank (formerly Chase Manhattan Bank). The preferred shareholders were entitled to quarterly cash dividends at an annual rate of 6%. In July 2002, we repurchased the entire 150,000 shares for $15 million plus accrued and unpaid dividends.

Gemstone. As part of the Gemstone transaction, our wholly owned subsidiary, Topaz issued a minority member interest to Gemstone Investor, an entity indirectly owned by Rabobank, for $300 million. Gemstone Investor is entitled to a cumulative preferred return of 8.03% on its interest. The agreements underlying this transaction expire in 2004, or earlier if we sell the international power assets owned indirectly by Topaz. Gemstone Investor's preferred interest is redeemable at liquidation value plus accrued and unpaid dividends. In January 2003, we notified Rabobank that we were exercising our right under the partnership agreements to purchase all of Rabobank's $50 million of equity in Gemstone. Unless we find a new partner, we will consolidate Gemstone upon our purchase of Rabobank's third party equity in Gemstone. At that time we will consolidate this minority member interest in Topaz.

Consolidated Partnership. In December 1999, Coastal Limited Ventures contributed assets to a limited partnership in exchange for a controlling general partnership interest. Limited interests in the partnership were issued to RBCC, an unaffiliated investor for $285 million. The limited partners were entitled to a cumulative priority return based on LIBOR. In July 2002, we repurchased the limited partnership interest in El Paso Production Oil & Gas Associates, L.P., formerly known as Coastal Oil and Gas Associates and a partnership formed with Coastal Limited Ventures, Inc. The payment of approximately $285 million to the unaffiliated investor was equal to the sum of the limited partner's outstanding capital plus unpaid priority returns.

El Paso Energy Capital Trust I, Coastal Finance I, El Paso Energy Capital Trust IV, Coastal Securities Company Limited, Trinity River, Clydesdale, Topaz and El Paso Tennessee Pipeline Co. are all either business trusts we control or companies in which we own all of the voting stock. Consequently, each of these entities is consolidated in our financial statements. However, each of these entities has issued preferred securities, and these preferred interests that are held by various unaffiliated investors are presented in our balance sheet as preferred interests of consolidated subsidiaries. The preferred distributions paid on these preferred interests are presented in our income statement as return of preferred interests of consolidated subsidiaries. Our accounting for some of these preferred interests of consolidated subsidiaries will be impacted by our adoption of the new accounting rules on consolidations in July 2003. For a discussion of the accounting impact, see Note 1 under *New Accounting Pronouncements Issued But Not Yet Adopted.*

20. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. On March 20, 2003, we entered into an agreement in principle (the Western Energy Settlement) with various public and private claimants, including the states of California, Washington, Oregon, and Nevada, to resolve the principal litigation, claims, and regulatory proceedings, which are more fully described below, against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the Western Energy Settlement. The Western Energy Settlement resulted in an after-tax charge of approximately $650 million in the fourth quarter of 2002. Among other things, the components of the settlement include:

- a cash payment of $100 million;
- a $2 million cash payment from our officer bonus pool;
- the issuance of approximately 26.4 million shares of El Paso common stock;
- delivery to the California border of $45 million worth of natural gas annually for 20 years beginning in 2004;
- a reduction of the pricing of our long-term power supply contracts with the California Department of Water Resources of $125 million over the remaining term of those contracts, which run through the end of 2005;
- payments of $22 million per year for 20 years;
- for a period of five years, EPNG will make available at its California delivery points 3,290 MMcf per day of capacity on a primary delivery point basis;
- for a period of five years, our affiliates will be subject to restrictions in subscribing for new capacity on the EPNG system; and
- no admission of wrongdoing.

The agreement in principle is subject to the negotiation of a formal settlement agreement, portions of which will then be filed with the courts and the FERC for approval. Upon approval, the parties will release us from covered claims that they may have against us and our subsidiaries for the period covered by the Western Energy Settlement, and the litigation, claims, and regulatory proceedings against us and our subsidiaries will be dismissed with prejudice.

California Lawsuits. We and several of our subsidiaries have been named as defendants in fifteen purported class action, municipal or individual lawsuits, filed in California state courts. These suits contend that our entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. Specifically, the plaintiffs argue that our conduct violates California's antitrust statute (Cartwright Act), constitutes unfair and unlawful business practices prohibited by California statutes, and amounts to a violation of California's common law restrictions against monopolization. In general, the plaintiffs are seeking (i) declaratory and injunctive relief regarding allegedly anticompetitive actions, (ii) restitution, including treble damages, (iii) disgorgement of profits, (iv) prejudgment and post-judgment interest, (v) costs of prosecuting the actions and (vi) attorney's fees. All fifteen cases have been consolidated before a single judge, under two omnibus complaints, one of which has been set for trial in September 2003. All of the class action and municipal lawsuits and all but one of the individual lawsuits will be resolved upon finalization and approval of the Western Energy Settlement.

In November 2002, a lawsuit titled *Gus M. Bustamante v. The McGraw-Hill Companies* was filed in the Superior Court of California, County of Los Angeles by several individuals, including Lt. Governor Bustamante acting as a private citizen, against numerous defendants, including our subsidiary EPNG, alleging the creation of artificially high natural gas index prices via the reporting of false price and volume information. This purported class action on behalf of California consumers alleges various unfair business practices and seeks restitution, disgorgement of profits, compensatory and punitive damages, and civil fines. This lawsuit will be resolved upon finalization and approval of the Western Energy Settlement.

In September 2001, we received a civil document subpoena from the California Attorney General, seeking information said to be relevant to the department's ongoing investigation into the high electricity prices in California. We have cooperated in responding to the Attorney General's discovery requests. This proceeding will be resolved upon finalization and approval of the Western Energy Settlement.

In May 2002, two lawsuits challenging the validity of long-term power contracts entered into by the California Department of Water Resources in early 2001 were filed in California state court against 26 separate companies, including our subsidiary El Paso Merchant Energy, L.P. (EPME or Merchant Energy). In general, the plaintiffs allege unfair business practices and seek restitution damages and an injunction against the enforcement of the contract provisions. These cases have been removed to federal court. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In January 2003, a lawsuit titled *IMC Chemicals v. EPME, et al.* was filed in California state court against us, EPNG and EPME. The suit arises out of a gas supply contract between IMC Chemicals (IMCC) and EPME and seeks to void the Gas Purchase Agreement between IMCC and EPME for gas purchases until December 2003. IMCC contends that EPME and its affiliates manipulated market prices for natural gas and, as part of that manipulation, induced IMCC to enter into the contract. In furtherance of its attempt to void the contract, IMCC repeats the allegations and claims of the California lawsuits described above. EPME intends to enforce the terms of the contract and counterclaim for contract damages. Our costs and legal exposure related to this lawsuit are not currently determinable.

Other Energy Market Lawsuits. The state of Nevada and two individuals filed a class action lawsuit in Nevada state court naming us and a number of our subsidiaries and affiliates as defendants. The allegations are similar to those in the California cases. The suit seeks monetary damages and other relief under Nevada antitrust and consumer protection laws. This lawsuit will be resolved upon finalization and approval of the Western Energy Settlement.

In December 2002, two class action complaints were filed, one in the state court of Oregon and the other in the federal court in the State of Washington, naming El Paso and more than forty other unrelated industry entities. In each case, the complaint makes general allegations that purchasers of natural gas and/or electricity, within the respective state, were overcharged during the period 2000 through 2002 by the defendants, who allegedly withheld supplies of energy, exercised improper control of the energy market and manipulated prices. These lawsuits allege violation of state statutes prohibiting unlawful trade practices, fraud and negligence. The relief sought includes injunctive relief, unspecified damages, and attorneys fees. The Washington complaint also seeks treble damages. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

A purported class action suit was filed in federal court in New York City in December 2002 alleging that El Paso, EPME, EPNG, and other defendants manipulated California's natural gas market by manipulating the spot market of gas traded on the NYMEX. We have not yet been served with the complaint. Our costs and legal exposure related to this lawsuit are not currently determinable.

In March 2003, the State of Arizona sued us, EPNG, EPME and other unrelated entities on behalf of Arizona consumers. The suit alleges that the defendants conspired to artificially inflate prices of natural gas and electricity during 2000 and 2001. Making factual allegations similar to those alleged in the California cases, the suit seeks relief similar to the California cases as well, but under Arizona antitrust and consumer fraud statutes. Our costs and legal exposure related to this lawsuit are not currently determinable.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action suits alleging violations of federal securities laws have been filed against us and several of our officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge. The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 challenging the accuracy or completeness of our February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002. It has since been dismissed, in light of similar claims being asserted in the consolidated suits in Houston. Four shareholder derivative actions have also been filed. One shareholder derivative lawsuit was filed in federal court in Houston in August 2002. This derivative action generally alleges the same claims as those made in the shareholder class action, has been consolidated with the shareholder class actions pending in Houston and has been stayed. A second shareholder derivative lawsuit was filed in Delaware State Court in October 2002 and generally alleges the same claims as those made in the consolidated shareholder class action lawsuit. A third shareholder derivative suit was filed in state court in Houston in March 2002, and a fourth shareholder derivative suit was filed in state court in Houston in November 2002. The third and fourth shareholder derivative suits both generally allege that manipulation of California gas supply and gas prices exposed El Paso to claims of antitrust conspiracy, FERC penalties and erosion of share value. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). Our costs and legal exposure related to this lawsuit are not currently determinable.

Carlsbad. In August 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. On June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: (1) failure to develop an adequate internal corrosion control program, with an associated proposed fine of $500,000; (2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; (3) failure to conduct continuing surveillance on its pipelines and consider, and respond appropriately to, unusual operating and maintenance conditions, with an associated proposed fine of $500,000; (4) failure to follow company procedures relating to investigating pipeline failures and thereby to minimize the chance of recurrence, with an associated proposed fine of $500,000; and (5) failure to maintain elevation profile drawings, with an associated proposed fine of $25,000. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations.

On February 11, 2003, the National Transportation Safety Board conducted a public meeting on its investigation into the Carlsbad rupture at which the NTSB adopted Findings, Conclusions and Recommendations based upon its investigation. In a synopsis of the Safety Board's report, the NTSB stated that it had determined that the probable cause of the August 19, 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program. The NTSB's final report is pending.

On November 1, 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture. EPNG is cooperating with the grand jury.

A number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All but one of these suits have been settled, with settlement payments fully covered by insurance. The remaining case is *Geneva Smith, et al. vs. EPEC and EPNG* filed October 23, 2000 in Harris County, Texas. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to five settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas on November 20, 2002 seeking an additional $180 million based upon their interpretation of earlier settlement agreements. In addition, plaintiffs' counsel for the settled New Mexico state court cases have notified EPNG that they intend to file suit on behalf of about twenty-three firemen and

EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. We have not been served with such a lawsuit. Our costs and legal exposure related to these lawsuits and claims are not currently determinable. However, we believe these matters will be fully covered by insurance.

Grynberg. In 1997, 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 underreport 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. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. 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, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries were named as defendants in *Quinque Operating Company, et al. v. Gas Pipelines and Their Predecessors, et al.*, filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. 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 plaintiff in this case seeks certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification has been argued and we are awaiting a ruling. Our costs and legal exposure related to this lawsuit are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in one such lawsuit in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of December 31, 2002, we had approximately $1,040 million accrued for all outstanding legal matters.

Environmental Matters

We are subject to 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, 2002, we had accrued approximately $482 million, including approximately $463 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $19 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $15 million of the accrual was related to discontinued coal mining operations.

Below is a reconciliation of our accrued liability as of December 31, 2001 to our accrued liability as of December 31, 2002:

	2002	2001
	(In millions)	
Balance as of January 1	$565	$318
Additions/adjustments for remediation activities	2	247
Payments for remediation activities	(70)	(30)
Other changes, net	(15)	30
Balance as of December 31	$482	$565

In addition, we expect to make capital expenditures for environmental matters of approximately $305 million in the aggregate for the years 2003 through 2007. These expenditures primarily relate to compliance with clean air regulations. For 2003, we estimate that our total remediation expenditures will be approximately $87 million, of which $3 million we estimate will be for capital related expenditures. In addition, approximately $64 million of this amount will be expended under government directed clean-up plans. The remaining $20 million will be self-directed or in connection with facility closures.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (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. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant 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.

Kentucky PCB Project. 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 complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the EPA. Despite TGP's remediation efforts, the agency may raise additional technical issues or seek additional remediation work in the future.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible costs under the PCB remediation project, with these surcharges to be collected over a defined collection period. TGP has twice received approval from the FERC to extend the collection period, which is now currently set to expire in June 2004. The agreement also provided for bi-annual audits of eligible costs. As of December 31, 2002, TGP has pre-collected PCB costs by approximately $115 million. The pre-collection will be reduced by future eligible costs incurred for the remainder of the remediation project. TGP is required to the extent actual expenditures are less than the amounts pre-collected, to refund to its customers the unused pre-collection amount, plus carrying charges incurred up to the date of the refunds. As of December 31, 2002, TGP has recorded a regulatory liability (included in other non-current liabilities on our balance sheet) for future refund obligations of approximately $55 million.

Coastal Eagle Point. From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey

Department of Environmental Protection (DEP). All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The DEP has assessed penalties totaling approximately $1.3 million for these alleged violations. The DEP has indicated a willingness to accept a reduced penalty and a supplemental environmental project. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments. Under its global refinery enforcement initiative, the Environmental Protection Agency (EPA) referred several Clean Air Act issues to the DEP. Our Eagle Point refinery expects to resolve these issues along with the DEP assessments. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair program. Alleged violations include failure to monitor all components, and failure to timely repair leaking components. During an August 2000 follow-up inspection, the EPA confirmed our Eagle Point refinery had improved implementation of the program. The Compliance Order requires documentation of compliance with the program. Our Eagle Point refinery has requested a conference with EPA to discuss the Order and the alleged violations. The EPA may seek a monetary penalty.

CERCLA Matters. We 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 58 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2002, we have estimated our share of the remediation costs at these sites to be between $29 million and $41 million. 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 CERCLA 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 determining our estimated liabilities.

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 our current reserves are adequate.

Rates and Regulatory Matters

Wholesale Power Customers' Complaints. In late 2001 and early 2002, several wholesale power customers filed complaints with the FERC against EPME and other wholesale power marketers (a list of the complaints is included below for which the primary customers are: Nevada Power Co. and Sierra Pacific Power Co. (NPSP), PacifiCorp, City of Burbank, the California Public Utilities Commission and the California Electricity Oversight Board (CPUC/CEOB). These customers entered into contracts with EPME and other wholesale power suppliers for the purchase of power to be delivered in the future. In these complaints, the customers have asked the FERC to reform the contracts they entered into with EPME and other wholesale power marketers on the grounds that they involve rates and terms that are "unjust and unreasonable" or "contrary to" the public interest within the meaning of the Federal Power Act (FPA). EPME and other respondents believe the allegations in the complaint are without merit and have asked the FERC to dismiss these complaints. In the NPSP matter, the ALJ issued an initial decision concluding that the contracts at issue should not be modified, and the complaints should be dismissed. In the CPUC/CEOB matter, the ALJ issued a decision finding the public interest standard applies to the contract at issue, which finding is consistent with the initial decision of the ALJ in the NPSP case. The CPUC/CEOB matter will be fully resolved upon finalization and approval of the Western Energy Settlement. In the PacifiCorp matter, the

ALJ issued an initial decision concluding that the complaint filed by PacifiCorp against EPME (and other respondents) should be dismissed with prejudice. The decisions of the ALJs will be submitted to the FERC for its review. On March 11, 2003, the City of Burbank matter was set for hearing.

CPUC Complaint Proceeding. In April 2000, the Public Utilities Commission of the State of California (CPUC) filed a complaint under Section 5 of the Natural Gas Act (NGA) with the FERC alleging that the sale of approximately 1.2 billion cubic feet per day of capacity by EPNG to EPME, both of whom are our wholly owned subsidiaries, raised issues of market power and violation of FERC's marketing affiliate regulations and asked that the contracts be voided. Although the FERC held that EPNG did not violate its marketing affiliate requirements, it established a hearing before an ALJ to address the market power issue. In the spring and summer of 2001, two hearings were held before the ALJ to address the market power issue and, at the request of the ALJ, the affiliate issue. In October 2001, the ALJ issued an initial decision on the two issues, finding that the record did not support a finding that either EPNG or EPME had exercised market power and that accordingly the market power claims should be dismissed. The ALJ found, however, that EPNG had violated FERC's marketing affiliate rule. EPNG and other parties filed briefs on exceptions and briefs opposing exceptions to the October initial decision.

Also in October 2001, the FERC's Office of Market Oversight and Enforcement filed comments stating that the record at the hearings was inadequate to conclude that EPNG had complied with FERC regulations in the transportation of gas to California. In December 2001, the FERC remanded the proceeding to the ALJ for a supplemental hearing on the availability of capacity at EPNG's California delivery points. On September 23, 2002, the ALJ issued his initial decision, again finding that there was no evidence that EPME had exercised market power during the period at issue to drive up California gas prices and therefore recommending that the complaint against EPME be dismissed. However, the ALJ found that EPNG had withheld at least 345 MMcf/d of capacity (and perhaps as much as 696 MMcf/d) from the California market during the period from November 1, 2000 through March 31, 2001. The ALJ found that this alleged withholding violated EPNG's certificate obligations and was an exercise of market power that increased the gas price to California markets. He therefore recommended that the FERC initiate penalty procedures against EPNG. EPNG and others filed briefs on exceptions to the initial decision on October 23, 2002; briefs opposing exceptions were filed on November 12, 2002. This proceeding will be resolved upon finalization and approval of the Western Energy Settlement.

Systemwide Capacity Allocation Proceeding. In July 2001, several of EPNG's contract demand or CD customers filed a complaint against EPNG at the FERC claiming, among other things, that EPNG's full requirements contracts or FR contracts (contracts with no volumetric limitations) should be converted to CD contracts, and that EPNG should be required to expand its system and give demand charge credits to CD customers when it is unable to meet its full contract demands. In July 2001, several of EPNG's FR customers filed a complaint alleging that EPNG had violated the Natural Gas Act and its contractual obligations to them by not expanding its system, at its cost, to meet their increased requirements.

On May 31, 2002, the FERC issued an order on the complaints in which it required that (i) FR service, for all FR customers except small volume customers, be converted to CD service; (ii) firm customers be assigned specific receipt point rights in lieu of their existing systemwide receipt point rights; (iii) reservation charge credits be given to all firm customers for failure to schedule confirmed volumes except in cases of force majeure; (iv) no new firm contracts be executed until EPNG has demonstrated there is adequate capacity on the system; and (v) a process be implemented to allow existing CD customers to turn back capacity for acquisition by FR customers in which process EPNG would remain revenue neutral. These changes were to be made effective November 1, 2002. The order also stated that the FERC expected EPNG to file for certificate authority to add compression to Line 2000 to increase its system capacity by 320 MMcf/d without cost coverage until its next rate case (i.e. January 1, 2006). EPNG had previously informed the FERC that it was willing to add compression to Line 2000 provided it was assured of rate coverage in the next rate case. On July 1, 2002, EPNG and other parties filed for clarification and/or rehearing of the May 31 order.

On September 20, 2002, at the urging of the FR shippers, the FERC issued an order postponing until May 1, 2003 the effective date of the FR conversions. That order also required EPNG to allocate among FR customers (i) the 320 MMcf/d of capacity that will be available from the addition of compression to Line 2000, and (ii) any firm capacity that expires under existing contracts between May 31, 2002, and May 1, 2003, thereby precluding it from reselling that capacity. In total, the September 20 order required that EPNG's FR customers pay only their current aggregate reservation charges for existing unsubscribed capacity, for the 230 MMcf/d of capacity made available in November 2002 by EPNG's Line 2000 project, for the 320 MMcf/d of capacity from the addition of compression to Line 2000, and for all capacity subject to contracts expiring before May 1, 2003. Beginning May 1, 2003, EPNG will be required to pay reservation charge credits when it is unable to schedule confirmed volumes except in cases of force majeure. Until May 1, 2003, it is required to pay partial reservation charge credits to CD customers when it is unable to schedule 95 percent of their monthly confirmed volumes except for reasons of force majeure and provided that there is no capacity available from other supply basins on its system.

Several pleadings have been filed in response to the September 20 order, including rehearing requests and requests by several customers to modify the order based on the ALJ's decision in the CPUC Complaint Proceeding discussed above. All such pleadings remain pending before the FERC. In the interim, EPNG is proceeding with the directives contained in the September 20 order.

On October 7, 2002, EPNG filed tariff sheets in compliance with the September 20 order to implement a partial demand charge credit for the period November 1, 2002 to May 31, 2003, and to allow California delivery points to be used as secondary receipt points to the extent of its backhaul displacement capabilities. EPNG proposed both a reservation and a usage charge for this service. On December 26, 2002, the FERC issued an order (i) denying EPNG's request to charge existing CD customers a reservation rate for California receipt service for the remaining term of the settlement, *i.e.,* through December 31, 2005; (ii) allowing EPNG to charge its maximum IT rate for the service; (iii) approving EPNG's proposed usage rate for the service until its next rate case; and (iv) requiring it to make a showing that capacity is available for any new shippers utilizing this service. EPNG made a revised tariff filing on January 10, 2003, in compliance with the December 26 order. On January 27, 2003, EPNG filed a request for rehearing on certain aspects of the December 26 order. That request is pending.

Rate Settlement. EPNG's current rate settlement establishes its base rates through December 31, 2005. Under the settlement, EPNG's base rates began escalating annually in 1998 for inflation. EPNG has the right to increase or decrease its base rates if changes in laws or regulations result in increased or decreased costs in excess of $10 million a year. In addition, all of EPNG's settling customers participate in risk sharing provisions. Under these provisions, EPNG received cash payments in total of $295 million for a portion of the risk EPNG assumed from capacity relinquishments by its customers (primarily capacity turned back to it by Southern California Gas Company and Pacific Gas and Electric Company which represented approximately one-third of the capacity of EPNG's system) during 1996 and 1997. The cash EPNG received was deferred, and EPNG recognizes this amount in revenues ratably over the risk sharing period. As of December 31, 2002, EPNG had unearned risk sharing revenues of approximately $32 million and had $13 million remaining to be collected from customers under this provision. Amounts received for relinquished capacity sold to customers, above certain dollar levels specified in EPNG's rate settlement, obligate it to refund a portion of the excess to customers. Under this provision, EPNG refunded $46 million of 2001 revenues to customers during 2001 and 2002. During 2002, EPNG established an additional refund obligation of $46 million, of which $32 million was refunded in 2002. The remainder will be refunded in 2003. Both the risk and revenue sharing provisions of the rate settlement extend through 2003.

Line 2000 Project. On July 31, 2000, EPNG applied with the FERC for a certificate of public convenience and necessity for its Line 2000 project, which was designed to replace old compression on the system with a converted oil pipeline, resulting in no increase in system capacity. In response to demand conditions on its system, however, EPNG filed in March 2001 to amend its application to convert the project to an expansion project of 230 MMcf/d. On May 7, 2001, the FERC authorized the amended Line 2000 project. EPNG placed the line in service in November 2002 at an approximate capital cost of $185 million. The cost of the Line 2000 conversion will not be included in EPNG's rates until its next rate case, which will be effective on January 1, 2006.

On October 3, 2002, pursuant to the FERC's May 31 and September 20 orders in the systemwide capacity allocation proceeding, EPNG filed with the FERC for a certificate of public convenience and necessity to add compression to its Line 2000 project to increase the capacity of that line by an additional 320 MMcf/d at an estimated capital cost of approximately $173 million for all phases. That application has been protested, and remains pending. In EPNG's request for clarification of the September 20 order, EPNG asked for assurances from the FERC that it will be able to begin cost recovery for this project at the time its next rate case becomes effective. That request remains pending.

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held on May 21, 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by our pipeline subsidiaries and others. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in their proposed form would, at a minimum, place additional administrative and operational burdens on us.

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. Several of our pipelines have entered into these transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power, and other issues related to negotiated rate programs. On September 25, 2002, our pipelines and others filed comments. Reply comments were filed on October 25, 2002. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. On August 1, 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent maintain investment grade credit ratings. On August 28, 2002, comments were filed. The FERC held a public conference on September 25, 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued an Accounting Release which was effective immediately. The Accounting Release provides guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, it did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed on August 30, 2002. The FERC has not yet acted on the rehearing requests.

Emergency Reconstruction of Interstate Natural Gas Facilities NOPR. On January 17, 2003, FERC issued a NOPR proposing to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were filed on February 27, 2003. At this time, we cannot predict the outcome of this rulemaking.

Pipeline Safety Notice of Proposed Rulemaking. On January 28, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Our pipelines intend to submit comments on the NOPR, which are due on or before April 30, 2003. At this time, we cannot predict the outcome of this rulemaking.

FERC Inquiry. On February 26, 2003, we received a letter from the Office of the Chief Accountant at the FERC requesting details of our announcement of 2003 asset sales and plans for our subsidiaries, SNG and ANR, to issue a combined $700 million of long-term notes. The letter requested that we explain how we intended to use the proceeds from SNG's and ANR's issuance of the notes and if the notes will be included in the two regulated companies' capital structure for rate-setting purposes. Our response to the FERC was filed on March 12, 2003, and we fully responded to the request.

Western Trading Strategies. EPME, our subsidiary, responded on May 22, 2002, to the FERC's May 8, 2002 request in Docket No. PA-02-2, seeking statements of admission or denial with respect to trading strategies designed to manipulate western power markets. EPME provided an affidavit stating that it had not engaged in these trading strategies.

Wash Trade Inquiries. On May 21 and 22, 2002, the FERC issued data requests in Docket PA-02-2, including requests for statements of admission or denial with respect to so-called "wash" or "round trip" trades in western power and gas markets. In May and June 2002, EPME responded, denying that it had conducted any wash or round trip trades (i.e., simultaneous, prearranged trades entered into for the purpose of artificially inflating trading volumes or revenues, or manipulating prices).

On June 7, 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC on July 15, 2002. On July 12, 2002, we received a federal grand jury subpoena for documents concerning so-called round trip or wash trades. We have complied with these requests.

Price Reporting to Indices. On October 22, 2002, the FERC issued a data request in Docket PA-02-2 to all of the largest North American gas marketers, including EPME, regarding price reporting of transactional data to the energy trade press. We engaged an outside firm to investigate the matters raised in the data request. EPME has provided information regarding its price reporting to indices to the FERC, the Commodities Futures Trading Commission (CFTC), and to the U.S. Attorney in response to their requests. The information provided indicates inaccurate prices were reported to the trade publications. EPME has no evidence that the reporting to the publications resulted in any unrepresentative price index. On March 26, 2003, we announced a settlement between EPME and CFTC of the price reporting matter providing for the payment by EPME of a civil monetary penalty of $20 million, $10 million of which is payable within three years, without admitting or denying the findings made in the CFTC order implementing the agreement.

Refunds Pricing. On August 13, 2002, the FERC issued a Notice Requesting Comment on Method for Determining Natural Gas Prices for Purposes of Calculating Refunds in ongoing California refund proceedings dealing with sales of electric power in which some of our companies are involved. Referencing a Staff Report also issued on August 13, 2002, the FERC requested comments on whether it should change the method for determining the delivered cost of natural gas in calculating the mitigated market-clearing price in the refund proceeding and, if so, what method should be used. Comments were filed on October 15, 2002. On December 12, 2002, the ALJ issued an Initial Decision, setting forth preliminary calculations of amounts owed. In the aggregate, the ALJ found that $3 billion is owed to natural gas suppliers, offset by an aggregate refund of $1.2 billion associated with prices charged in excess of the mitigated market clearing prices. Upon the finalization and approval of the Western Energy Settlement, claims by many of the claimants in this proceeding for credits against amounts due EPME will be resolved; however, the specific amount of the adjustment is indeterminable at this time. The full FERC is expected to review the decision later in 2003. We cannot predict the final outcome of this matter.

Australia. In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment of approximately $200 million. EPIC Energy Australia appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The court directed the regulator to review its position and comply with applicable regulatory law. During the fourth quarter of 2002, events in the business of Epic Energy Australia, including unanticipated cash requirements, made it apparent that a cash equity infusion would be required to refinance the debt of Epic Energy(WA) Nominee Pty. that matures and is payable in full in 2003. With our fourth quarter credit downgrades by the rating agencies and the demands on our liquidity, we concluded that we would not contribute any further equity into our Epic Energy Western Australian investment. As a result, we recognized an impairment of $153 million related to our investment in Epic Energy's Dampier-to-Bunbury Pipeline.

Southwestern Bell Proceeding. We are engaged in proceedings with Southwestern Bell involving disputes regarding our telecommunications interconnection agreement in our metropolitan transport business. In July 2002, we received a favorable ruling from the administrative law judge in Phase 1 of the proceedings. We anticipate a determination from the PUC of Texas on the administrative law judge's recommendation no later than the second quarter of 2003. Despite the favorable ruling from the administrative law judge, the PUC retains the right to affirm or reject the award and any significant rejection of the award could negatively impact our metro transport business. An adverse resolution to the proceeding by the PUC could have a negative impact on our ongoing operations and prospects in this business.

FCC Triennial Review. In this proceeding, the FCC, pursuant to its Congressional mandate, is reexamining the entire list of Unbundled Network Elements (UNEs), including high capacity loops and transport and dark fiber, to determine if any should be removed or qualified. It is possible that the FCC may either eliminate or set more stringent offering guidelines for some of the existing UNE's. Although EPGN has no reason to assume that dark fiber or high capacity loops or transport may be eliminated, any ruling that seriously impaired its ability to access these UNEs would significantly affect its current business model. EPGN has filed comments and an order is expected by April 2003.

FCC Broadband Docket. The FCC has issued a Notice of Proposed Rule Making (NPRM) for Broadband Service and asked for general comments on a vast array of issues. The NPRM indicates that the FCC is inclined to declare high-speed, DSL internet access service as an information service. This would allow Incumbent Local Exchange Carriers (ILECs) to stop leasing their DSL internet service to third party competitors for resale to customers. ILECs have also submitted proposals that would effectively deregulate all optical level and high-speed copper based services. If the FCC adopted the NPRM proposal, the results would critically affect EPGN's business. EPGN filed initial comments, in conjunction with other CLEC's. EPGN also filed joint reply comments on July 3, 2002, stressing both the illegality of the proposed finding and the national security implications. Certain ILECs are advocating the position that all high capacity copper and fiber lines should be found to be "information services", thereby exempting them from having to lease their lines to EPGN. We have opposed such a holding which we believe would be unlawful. A decision is expected sometime during the first half of 2003.

While the outcome of our outstanding legal matters, environmental matters, and rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters. It is also possible that these matters could impact our debt rating and credit rating. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations under the subheading Recent Developments. Further, for environmental matters, 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 new information regarding our outstanding legal matters, environmental matters and rates and regulatory matters becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations, our financial position, and on our cash flows in the period the event occurs.

Other Matters

LNG Time Charters. During 2001 and 2002, we contracted to charter four LNG tankers, with an option to charter a fifth ship, to transport LNG from supply areas to domestic and international market centers. In February 2003, following our announced plan to minimize our involvement in the LNG business, we entered into various agreements with the ship owners under which all four of the ship charters and our option for chartering the fifth ship were cancelled in consideration of payments by us totaling $24 million. On two of the ship charters, the ship owners assumed responsibility for the charter of those vessels, and we paid $20 million for the capital costs associated with fitting those two ships with regasification capabilities. In connection with transferring the chartering responsibilities back to the ship owners, we agreed to provide letters of credit, fully collateralized by cash, equal to $120 million that could be drawn on by ship owners to cover additional capital costs and any shortfalls in the rates at which they are able to charter the vessels compared to the rates provided for in the original charter agreements adjusted for capital costs we have already paid. In the event that the ship owners are able to charter the ships at rates in excess of the original rates, as adjusted, we will share in the benefits. We also retained rights to charter some of the vessels for use in our future LNG activities. In connection with these transactions, our future exposure to the ship arrangements is limited to $120 million.

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., (EPMI) filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and NGL and the trading of physical natural gas, power, petroleum and financial derivatives.

Our Merchant Energy positions are governed under a master International Swap Dealers Association, Inc. agreement, various master natural gas agreements, a master power purchase and sale agreement, and other commodity agreements. We terminated most of these trading-related contracts, which we believe was proper and in accordance with the terms of these contracts. In October 2002, we filed proofs of claim for our domestic trading positions against Enron trading entities in an amount totaling approximately $318 million. Also in October 2002, our European trading business asserted $20 million in claims against Enron Capital and Trade Resources Limited which is subject to proceedings in the United Kingdom. After considering the cash margins Enron has deposited with us as well as the reserves we have established, our overall Merchant Energy exposure to Enron is $29 million, which is classified as current accounts and notes receivable. We believe this amount is reasonable based on offers received to purchase the claims.

In February 2003, Merchant Energy received a letter from EPMI demanding payment under a March 2001 Power Purchase and Sale Agreement (Agreement) of approximately $46 million. Merchant Energy responded to the February 2003 demand letter denying that any sums were due EPMI under the Agreement. In addition, EPMI has now made demand on us for this sum based on an August 2, 2001 guaranty agreement. EPMI has now filed a lawsuit against Merchant Energy and El Paso in the United States Bankruptcy Court for the Southern District of New York seeking to collect these sums. We have denied liability.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. The September 20 order in the EPNG capacity allocation proceeding discussed in *Rates and Regulatory Matters* above prohibits EPNG from remarketing Enron capacity that was not remarketed prior to May 31, 2002. EPNG has sought rehearing of the September 20 order. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since the rejection date.

As a result of current circumstances surrounding the energy sector, the creditworthiness of several industry participants has been called into question. We have taken actions to mitigate our exposure to these participants; however, should several industry participants file for Chapter 11 bankruptcy protection and contracts with our various subsidiaries are not assumed by other counterparties, it could have a material adverse effect on our financial position, operating results or cash flows.

Broadwing Arbitration. In June 2000, El Paso Global Networks (EPGN), formerly known as El Paso Communications Company, entered into an agreement with Broadwing Communications Services (Broadwing) to construct and maintain a fiber optic telecommunications system from Houston, Texas to Los Angeles, California. In May 2002, EPGN terminated its agreements with Broadwing due to Broadwing's failure to meet its contractual obligations. Broadwing disputed EPGN's right to terminate the agreements. Subsequently, EPGN filed a demand for arbitration and named its arbitrator. We have also sought and obtained injunctive relief to require Broadwing to perform maintenance activity and prohibit it from removing materials or equipment purchased for the project. If it is determined that we properly terminated the contract, Broadwing is required to return all money paid by us which is $62 million and transfer all of the work completed to date free and clear of any liens. The arbitration is scheduled for the fourth quarter of 2003. In the fourth quarter of 2002, we wrote down the value of this long-haul route by $4 million, leaving a total investment of $104 million.

Economic Conditions of Brazil. We have investments in power, pipeline and production projects in Brazil, including an investment in Gemstone, with an aggregate exposure, including financial guarantees, of approximately $1.8 billion. During 2002, Brazil experienced a significant decline in its financial markets due largely to concerns over the refinancing of Brazil's foreign debt and the presidential elections which were completed in late October 2002. These concerns have contributed to higher interest rates on local debt for the government and private sectors, have significantly decreased the availability of funds from lenders outside of Brazil and have decreased the amount of foreign investment in the country. These factors have contributed to a downgrade of Brazil's foreign currency debt rating and a 52 percent devaluation of the local currency against the U.S. dollar during 2002. These developments are likely to delay the implementation of project financings underway in Brazil. The International Monetary Fund announced in the fourth quarter a $30 billion loan package for Brazil; however, the release of the majority of the money will depend on Brazil committing to specified fiscal targets in 2003. In addition, Brazil's newly elected President may impose changes affecting our business, including imposing tariff controls on electricity and fuels. We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our investment in the country, but we continue to monitor the economic situation and any potential changes in governmental policy. Future developments in Brazil could cause us to reassess our exposure.

Gemstone, our affiliate, owns a 60 percent interest in a 484 MW gas-fired power project, known as the Araucaria project, located near Curitiba, Brazil. Our investment in the Araucaria project was $176 million at December 31, 2002. The project company in which we have an ownership interest has a 20 year power purchase agreement (PPA) with Copel, a regional utility. Copel is approximately 60 percent owned by the State of Parana. After the recent elections in Brazil, the new Governor of the State of Parana publicly characterized the Araucaria project as unfavorable to Copel and the State of Parana and promised a full review of the transaction. Subsequent to this announcement, Copel informed us that they will not pay capacity payments due under the PPA pending that review. Previous payments made under the PPA were made with a reservation of rights with respect to the enforceability of the contract. We are meeting with the government as well as new management at Copel to discuss Copel's obligations under the power purchase agreement. If we are unable to come to a satisfactory resolution of the current issues under the PPA, we may be required to initiate enforcement of our remedies under the contract, including filing an arbitration proceeding under the International Chamber of Commerce rules in Paris. If we do not prevail in that proceeding, or are not otherwise able to enforce our remedies under the contract, we could be required to impair our investment in the project. Our losses would be limited to our investment.

Meizhou Wan Power Project. We own a 25 percent equity interest in a 734 MW, coal-fired power generating project, Meizhou Wan Generating, located in Fuzhou, People's Republic of China. Our investment in the project was $56 million at December 31, 2002, and we have also issued $34 million in guarantees and letters of credit for equity support and debt service reserves for the project. The project debt is collateralized only by the project's assets and is non-recourse to us. The project declared that it was ready for commercial operations in August 2001; however, the provincial government, who also buys all power generated from the project, has not accepted the project for commercial operations. In October 2002, we reached an interim agreement to allow the plant to operate and sell power at reduced rates until March 2003 while a long-term resolution to existing and past contract terms is negotiated. The price the project receives from the sale of power in the interim agreement is expected to be sufficient to provide for the operating costs and debt service of the project, but does not provide for a return on investment to the project's owners. If the project is unable to reach a long-term agreement with the provincial government, with higher rates than in the interim agreement, we could be required to impair our investment in the project, since cash flows from the project would not be sufficient to provide us with a return of our investment, and we may incur additional losses if our guarantees and letters of credit are called upon. Our losses are limited to the extent of our investment, guarantees and letters of credit. At December 31, 2002, we impaired $7 million of our goodwill related to our investment in this project.

Milford Power Project. We own a 25 percent direct equity interest in a 540 MW power plant construction project located in Milford, Connecticut. Chaparral, our affiliate, owns an additional 70 percent interest in this project. The project has been financed through equity contributions, construction financing from lenders that is recourse only to the project and through a construction management services agreement that we funded. This project has experienced significant construction delays, primarily associated with technological difficulties with its turbines including the inability to operate on both gas and fuel oil or to operate at its designed capacity as specified in the construction contract. In October 2001, we entered into a construction management services agreement providing additional funding through October 1, 2002. The construction contractor failed to complete construction of the plant prior to October 1, 2002, in accordance with the terms and specifications of the construction contract. As a result, the project was in default under its construction lending agreement. On October 25, 2002, we entered into a standstill agreement with the construction lending banks that expired on December 2, 2002. We will continue negotiating with the contractor and with the lending banks to attempt to reach agreements on contract disputes, including resolution of liquidated damages that are due to the project under the terms of the construction contract and for successful completion of plant construction. On March 4, 2003, we provided a notice to Milford declaring an event of default under the fuel supply agreement between us and Milford due to non-payment by Milford. On March 6, 2003, Milford received a notice from its lenders stating that the lenders intended to commence foreclosure on the project in accordance with the lending agreement within 30 days. As a result of the default under the construction lending agreement, we evaluated our investment and recorded an impairment charge of $17 million while Chaparral recorded an impairment charge of $44 million in the fourth quarter of 2002. At December 31, 2002, our direct investment in the project was $67 million of loans to Milford under a construction management services agreement. We have also provided a guarantee of $8 million to fund a debt service account for Milford. We may be required to fund the account should the facility not be financially able to do so within two years from its commercial operations date. If we are unable to reach a negotiated settlement of the disputes with the lending banks, the banks may have the right to accelerate the construction loan and foreclose on the project which may result in an impairment of our construction loans, including the guaranteed amount in the project. If this occurred, we could record an impairment charge of up to $75 million.

Berkshire Power Project. We own a 25 percent direct equity interest in a 261 MW power plant located in Massachusetts. Chaparral, our affiliate, owns an additional 31.4 percent interest in this project. The construction contractor failed to deliver a plant capable of operating on both gas and fuel oil, or capable of operating at its designed capacity. Berkshire is negotiating with the contractor with respect to its failure to deliver the project in accordance with guaranteed specifications, including fuel oil firing capability. During the third quarter of 2002, the project lenders asserted that Berkshire was in default on its loan agreement. Berkshire is in the process of negotiating with its lenders to resolve disputed contract terms. Failure to reach a satisfactory resolution in these matters could have a material adverse effect on the value of our investment in the project. At December 31, 2002, our direct investment in Berkshire was $20 million, including receivables of $16 million under a subordinated fuel agreement, and Chaparral's investment was $1 million. We continue to discuss settlement opportunities with our construction contractor.

PPN Power Project. Our subsidiary owns a 26 percent minority equity interest in a 325 MW dual fuel (naphtha and natural gas) fired generating plant located in Tamil Nadu Province, India. The project achieved commercial operations in April 2001 and obtained dual fuel capability in September 2002. The project sells power to the Tamil Nadu Electricity Board (TNEB). The TNEB has paid for power at a rate lower than the rate called for in the power purchase agreement and at December 31, 2002 the project had overdue receivables of $36 million. The TNEB has requested an increase in the rates that it is permitted to charge customers within its service territory in order to provide revenues sufficient to make payments owed to us. Amounts currently being paid are sufficient to cover debt service and normal operating expenses but are insufficient to cover maintenance and a return on equity. If the project is unable to reach a long-term agreement with the TNEB to collect rates higher than those currently being paid, the project may incur losses as the plant continues to operate. Recent events have also made the possibility of long term operations on natural gas less likely which has the effect of increasing the operating cost of the project because the use of naphtha makes electric generation more expensive on a per kilowatt hour basis. At December 31, 2002, we impaired all of our investment in this project, which totaled $41 million.

Cases

The California cases discussed above are five filed in the Superior Court of Los Angeles County *(Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000*; *Berg v. Southern California Gas Company, et al,* filed December 18, 2000*; *County of Los Angeles v. Southern California Gas Company, et al,* filed January 8, 2002*; *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,* both filed March 20, 2001*); two filed in the Superior Court of San Diego County *(John W.H.K. Phillip v. El Paso Merchant Energy;* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000*); and two filed in the Superior Court of San Francisco County *(Sweetie's et al v. El Paso Corporation, et al,* filed March 22, 2001*; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda *(Dry Creek Corporation v. El Paso Natural Gas Company, et al,* filed December 10, 2001*); and five filed in the Superior Court of Los Angeles County *(The City of San Bernardino v. Southern California Gas Company, et al; The City of Vernon v. Southern California Gas Company; The City of Upland v. Southern California Gas Company, et al; Edgington Oil Company v. Southern California Gas Company, et al; World Oil Corporation, et al. v. Southern California Gas Company, et al,* filed December 27, 2002*). The two long-term power contract lawsuits are *James M. Millar v. Allegheny Energy Supply Company, et al.* filed May 13, 2002 in the Superior Court, San Francisco County, California and *Tom McClintock et al. v. Vikram Budhrajaetal* filed May 1, 2002 in the Superior Court, Los Angeles County, California. The cases referenced in Other Energy Market Lawsuits are: *The State of Nevada, et al. v. El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy Company, et al.* filed November 2002 in the District Court for Clark County, Nevada*; *Sharon Lynn Lodewick v. Dynegy, Inc. et al.* filed December 16, 2002 in the Circuit Court for the County of Multnomah, State of Oregon; *Nick A. Symonds v. Dynegy, Inc. et al.* filed December 20, 2002 in the United States District Court for the Western District of Washington, Seattle; *Henry W. Perlman, et al. v. San Diego Gas & Electric et al.* filed December 2002, in the United States District Court, Southern District of New York. *State of Arizona v El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy Company, et al. filed March 10, 2003 in the Superior Court, Maricopa County, Arizona.*

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and *Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and*

*Cases to be dismissed upon finalization and approval of the Western Energy Settlement.

Rodney D. Erskine, filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002. The purported shareholder action filed in the Southern District of New York is *IRA F.B.O. Michael Conner et al v. El Paso Corporation, William Wise, H. Brent Austin, Jeffrey Beason, Ralph Eads, D. Dwight Scott, Credit Suisse First Boston, J.P. Morgan Securities,* filed October 25, 2002.

The shareholder derivative actions filed in Houston are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002. *John Gebhart v. Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and William Wise,* filed March 2002; *Marilyn Clark v. El Paso Natural Gas, El Paso Merchant Energy, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and William Wise* filed in November 2002. The shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

The customer complaints filed at the FERC against EPME and other wholesale power marketers are: *Nevada Power Company and Sierra pacific Power Company vs. El Paso Merchant Energy, L.P.; California Public Utilities Commission vs. Sellers of Long-Term Contracts to the California Department of Water and California Electricity Oversight Board vs. PacifiCorp vs. El Paso Merchant Energy, L.P., and City of Burbank, California vs. Calpine Energy Services, L.P., Duke Energy Trading and Marketing, LLC, El Paso Merchant Energy*.

The ERISA Class Action Suit is *William H. Lewis III v. El Paso Corporation, H. Brent Austin and unknown fiduciary defendants 1-100.*

Commitments and Purchase Obligations

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2003 until 2053. As of December 31, 2002, our total commitments under operating leases were approximately $844 million.

Under several of our leases, we have provided residual value guarantees to the lessor. For the total outstanding residual value guarantees on our operating leases at December 31, 2002, see *Residual Value Guarantees* below.

Minimum annual rental commitments at December 31, 2002, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2003	$174
2004	147
2005	113
2006	89
2007	56
Thereafter	265
Total	$844

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $13 million due in the future under noncancelable subleases.

Rental expense on our operating leases for the years ended December 31, 2002, 2001 and 2000 was $196 million, $147 million, and $198 million.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas.

As of December 31, 2002, we had approximately $2.5 billion of both financial and performance guarantees outstanding. Of this amount, approximately $1.0 billion relates to our Chaparral investment and $950 million relates to our Gemstone investment. The remaining $558 million relates to other global power equity investments, including some of the projects under Chaparral and Gemstone, and pipeline and petroleum activities.

Residual Value Guarantees. Under two of our operating leases, we have provided residual value guarantees to the lessor. Under these guarantees, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is typically equal to the outstanding loan amounts owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The levels of our residual value guarantees range from 86.2 percent to 89.9 percent of the original cost of the leased assets. Accounting for these residual value guarantees will be impacted effective July 1, 2003, by our adoption of the new accounting rules on consolidations. For a discussion of the accounting impact of these new rules, see Note 1.

As of December 31, 2002, we had purchase options and residual value guarantees associated with operating leases for the following assets:

Asset Description	Purchase Option	Residual Value Guarantee	Lease Expiration
	(In millions)		
Lakeside Technology Center telecommunications facility	$275	$237	2006
Facility at Aruba refinery	370	333	2006

Other Commercial Commitments. We have various other commercial commitments and purchase obligations. At December 31, 2002, we had firm commitments under transportation and storage capacity contracts of $1.4 billion, commodity purchase commitments of $36 million that are not part of our trading activities and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $825 million.

21. Retirement Benefits

Pension Benefits

We maintain a defined benefit pension plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Employees who were participating in El Paso's defined benefit pension plan on December 31, 1996 receive the greater of cash balance benefits or prior plan benefits accrued through December 31, 2001. Effective January 1, 2000, Sonat's pension plan was merged into our pension plan. Sonat employees who were participants in the Sonat pension plan on December 31, 1999 receive the greater of cash balance benefits or the Sonat plan benefits accrued through December 31, 2004.

Prior to our merger with Coastal, Coastal provided non-contributory pension plans covering substantially all of its U.S. employees. On April 1, 2001, Coastal's primary plan was merged into our existing plan. Coastal employees who were participants in Coastal's primary plan on March 31, 2001 receive the greater of cash balance benefits or the Coastal plan benefits accrued through March 31, 2006.

Following our mergers with Coastal and Sonat, we offered an early retirement incentive program for eligible employees of these organizations. These programs offered enhanced pension benefits to individuals who elected early retirement. Charges incurred in connection with the Sonat program were $8 million and those in connection with the Coastal program were $152 million.

Separate plans were provided to employees of our coal and convenience store operations. We also participate in one multi-employer pension plan for the benefit of our employees who are union members. Our contributions to this plan were not material for 2002 or 2001.

Retirement Savings Plan

We maintain a defined contribution plan covering all of our U.S. employees. Prior to May 1, 2002, we matched 75 percent of participant basic contributions up to 6 percent, with the matching contribution being made to the plan's stock fund which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, we suspended the matching contribution. Amounts expensed under this plan were approximately $28 million, $30 million and $35 million for the years ended December 31, 2002, 2001 and 2000.

Other Postretirement Benefits

We provide postretirement medical benefits for Coastal Coal and closed groups of retired employees of EPNG, El Paso Tennessee, Sonat, and Coastal, and limited postretirement life insurance benefits for current and retired employees. As of January 31, 2003, the sale of the Coastal Coal operations were completed. As a result of the sale, Coastal Coal is now a closed group of retired employees. See Note 9 for a further discussion of this matter. Other postretirement employee benefits (OPEB) are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for TGP, EPNG or SNG differ from the amounts recovered in rates, a regulatory asset or liability is recorded.

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 reserve the right to change these benefits.

The following table details our projected benefit obligation, accumulated benefit obligation, fair value of plan assets as of September 30 and related balance sheet accounts as of December 31:

	Primary Pension Plan		Other Pension Plans	
	2002	2001	2002	2001
	(In millions)			
Projected benefit obligation	$1,911	$1,831	$177	$135
Accumulated benefit obligation	1,857	1,773	167	124
Fair value of plan assets	1,984	2,380	87	99
Accrued benefit liability	—	—	75	61
Prepaid benefit cost	898	793	—	28
Accumulated other comprehensive loss	—	—	55	—
Intangible asset	—	—	1	—

We recorded a loss on our other pension plans as other comprehensive loss, because the accumulated benefit obligation exceeded the fair value of plan assets for each of those plans as of September 30, 2002. Included in other pension plans as of September 30, 2001 are two pension plans whose accumulated benefit obligation exceeded the fair value of plan assets. The projected benefit obligation, accumulated benefit obligation, and accrued benefit liability associated with these plans were $51 million, $47 million and $61 million at September 30, 2001.

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. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of period	$1,966	$1,680	$ 560	$ 570
Service cost	33	30	1	1
Interest cost	135	117	38	42
Participant contributions	—	—	20	17
Plan amendments	—	4	—	(12)
Settlements, curtailments and special termination benefits	—	137	—	17
Actuarial (gain) or loss	129	135	17	(14)
Benefits paid	(175)	(137)	(78)	(61)
Benefit obligation at end of period	$2,088	$1,966	$ 558	$ 560
Change in plan assets				
Fair value of plan assets at beginning of period	$2,479	$3,190	$ 168	$ 188
Actual return on plan assets	(246)	(581)	(14)	(30)
Employer contributions	14	7	68	54
Participant contributions	—	—	20	17
Benefits paid	(175)	(137)	(78)	(61)
Fair value of plan assets at end of period	$2,072	$2,479	$ 164	$ 168
Reconciliation of funded status				
Funded status at end of period	$ (16)	$ 513	$(394)	$(392)
Fourth quarter contributions and income	4	37	17	11
Unrecognized net actuarial loss (gain)[(1)]	921	252	25	(15)
Unrecognized net transition obligation	(1)	(9)	23	31
Unrecognized prior service cost	(30)	(32)	(8)	(9)
Prepaid (accrued) benefit cost at December 31,	$ 878	$ 761	$(337)	$(374)

[(1)] Our unrecognized net actuarial loss as of September 30, 2002, and for the year ended December 31, 2002, was primarily the result of a decrease in the discount rate used in the actuarial calculation and lower actual returns on plan assets compared to our expected return during 2002. We recognize the difference between the actual return and our expected return over a three year period as permitted by SFAS No. 87.

The current liability portion of the postretirement benefits was $35 million as of December 31, 2002 and $46 million as of December 31, 2001. Benefit obligations are based upon actuarial estimates as described below. Where these assumptions differed, average rates have been presented.

	Pension Benefits			Postretirement Benefits		
	Year Ended December 31,					
	2002	2001	2000	2002	2001	2000
	(In millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 33	$ 35	$ 38	$ 2	$ 1	$ 3
Interest cost	135	134	121	38	42	43
Expected return on plan assets	(260)	(311)	(277)	(9)	(10)	(8)
Amortization of net actuarial gain	—	(41)	(30)	(1)	(2)	(2)
Amortization of transition obligation	(6)	(6)	(6)	8	8	13
Amortization of prior service cost	(3)	(2)	(3)	(1)	(1)	—
Settlements, curtailment, and special termination benefits	—	137	—	—	65	—
Net benefit cost (income)	$(101)	$ (54)	$(157)	$ 37	$103	$49

The following table details the weighted average assumptions we used for our pension and other postretirement plans for 2002 and 2001:

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.80%	10.00%	7.50%	7.50%
Rate of compensation increase	4.00%	4.50%	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 11.0 percent in 2002, gradually decreasing to 5.5 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:

	2002	2001
	(In millions)	
One Percentage Point Increase		
Aggregate of Service Cost and Interest Cost	$ 1	$ 1
Accumulated Postretirement Benefit Obligation	$ 20	$ 22
One Percentage Point Decrease		
Aggregate of Service Cost and Interest Cost	$ (1)	$ (1)
Accumulated Postretirement Benefit Obligation	$(19)	$(21)

22. Capital Stock

Common Stock

In May 2002, we increased our authorized capitalization to 1.5 billion shares of common equity. In June 2002, we issued approximately 51.8 million additional shares of common stock for approximately $1 billion, net of issuance costs of approximately $31 million.

In December 2001, we issued 20.3 million shares of common stock for approximately $863 million (net of issuance costs).

Equity Security Units

In June 2002, we issued 11.5 million, 9% equity security units. Equity security units consist of two securities: i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86% and that requires its holder to buy El Paso common stock to be settled on August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14% beginning August 16, 2002. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders' obligation to purchase shares of our common stock under the purchase contracts.

When the purchase contracts are settled in 2005, we will issue El Paso common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 24 million shares and up to a maximum of 28.8 million shares on the settlement date, depending on our average stock price. We recorded approximately $43 million of other non-current liabilities to reflect the present value of the quarterly contract adjustment payments that we are required to make on these units at an annual rate of 2.86% of the stated amount of $50 per purchase contract with an offsetting reduction in additional paid-in capital. The quarterly contract adjustment payments are allocated between the liability recognized at the date of issuance and additional paid-in capital based on a constant rate over the term of the purchase contracts. Fees and expenses incurred in connection with the equity security units offering were allocated between the senior notes and the purchase contracts based on their respective fair values on the issuance date. The amount allocated to the senior notes is recognized as interest expense over the term of the senior notes. The amount allocated to the purchase contracts is recorded as additional paid-in capital.

FELINE PRIDES℠

In August 2002, we issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES℠ program. In return for the issuance of stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004, that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

Preferred Stock

As part of our balance sheet enhancement plan announced in December 2001, we completed amendments to our Chaparral and Gemstone agreements in 2002 which eliminated the Series B Mandatorily Convertible Single Reset Preferred Stock issued in connection with the Chaparral third party notes, and eliminated all of the Series C Mandatorily Convertible Single Reset Preferred Stock issued in connection with the Gemstone third party notes.

Dividend

On February 5, 2003, we declared a quarterly dividend of $0.04 per share on our common stock, payable on April 7, 2003, to stockholders of record on March 7, 2003. Also, during the year ended December 31, 2002, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of $25 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

23. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using Accounting Principles Board Opinion No. 25 and its related interpretations. Under our employee plans, we may issue incentive stock options on our common stock (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. Under our non-employee director plans, we may issue non-qualified stock options and deferred shares of common stock. We have reserved approximately 69 million shares of common stock for existing and future stock awards. As of December 31, 2002, approximately 24 million shares remained unissued.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2002, 2001, and 2000. Our 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 except in special circumstances. A summary of our stock options and stock options outstanding as of December 31, 2002, 2001, and 2000 is presented below:

	Stock Options					
	2002		2001		2000	
	# 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	44,822,146	$50.02	19,664,151	$34.43	22,511,704	$32.80
Granted	3,435,138	$35.41	28,327,468	$60.19	1,065,110	$41.35
Exercised	(310,611)	$22.44	(1,396,409)	$25.88	(3,648,752)	$25.99
Forfeited	(4,738,299)	$51.83	(1,773,064)	$58.00	(263,911)	$38.44
Outstanding at end of year	43,208,374	$49.18	44,822,146	$50.02	19,664,151	$34.43
Exercisable at end of year	25,493,152	$43.00	14,357,245	$33.58	12,431,102	$30.51

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/02	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 12/31/02	Weighted Average Exercise Price
$ 7.00 to $21.40	3,124,597	3.3	$16.01	2,582,018	$16.26
$21.41 to $42.90	14,327,024	5.5	$37.71	12,625,816	$37.44
$42.91 to $64.30	18,512,565	7.3	$55.28	8,872,672	$54.34
$64.31 to $71.50	7,244,188	7.6	$70.58	1,412,646	$70.44
$ 7.00 to $71.50	43,208,374	6.4	$49.18	25,493,152	$43.00

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:	2002	2001	2000
Expected Term in Years	6.95	7.25	7.00
Expected Volatility	43.4%	26.6%	23.9%
Expected Dividends	1.8%	3.0%	3.0%
Risk-Free Interest Rate	3.2%	4.7%	5.0%

The Black-Scholes weighted average fair value of options granted during 2002, 2001 and 2000 was $14.23, $15.75 and $10.16.

Restricted Stock

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our 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 established performance targets. Restricted stock awards representing 1.4 million, 2.3 million, and

0.4 million shares were granted during 2002, 2001 and 2000 with a weighted average grant date fair value of $38.45, $62.10 and $34.82 per share. At December 31, 2002, 4.4 million shares of restricted stock were outstanding. The value of restricted shares subject to performance vesting 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. The value of time vested restricted shares is determined at their issuance date and this cost is amortized to compensation expense over the period of service. For 2002, 2001, and 2000, these charges totaled $73 million, $67 million, and $13 million. Included in deferred compensation at December 31, 2000, is $69 million related to options that will be converted automatically into common stock at the end of their vesting period. These options met all performance targets in December 2000.

Performance Units

We award eligible 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 or total shareholder return during the vesting period relative to our peer group. 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 or changes in expected total shareholder return. Amounts charged to compensation expense in 2002, 2001 and 2000 were $10 million, $64 million and $25 million. Our 2001 expense includes a $51 million charge to pay out all of our outstanding phantom stock options. In June 2002, we reduced the amount we were accruing for the performance units issued to executives. The adjustment decreased our total liability by $21 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. Five million shares of common stock are authorized for issuance under this plan.

The following table presents the number of shares issued and the price per share by quarter for the year ended December 31:

	2002		2001		2000	
	Shares	**Price per Share**	**Shares**	**Price per Share**	**Shares**	**Price per Share**
1st Quarter	205,118	$38.02	75,851	$55.10	90,718	$32.33
2nd Quarter	414,546	$17.20	90,319	$44.22	87,622	$32.33
3rd Quarter	466,655	$ 6.61	104,404	$34.58	84,780	$32.33
4th Quarter	283,313[(1)]	$ 5.95	42,570[(1)]	$38.34	83,212	$32.33
Total	1,369,632		313,144		346,332	

(1) Since many employees reached the maximum contribution that is imposed by Section 423 of the Internal Revenue Code in the third quarter of 2001 and 2002, they were excluded from participating in the fourth quarter of 2001 and 2002.

Funds we receive under this program 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. Effective January 1, 2003, we have suspended our employee stock purchase program.

24. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. In the second quarter of 2002, we reclassified our historical coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. All periods were restated to reflect this change.

Our Pipelines segment provides natural gas transmission, storage, gathering and related services in the U.S. and internationally. We conduct our activities primarily through seven wholly owned and seven partially owned interstate transmission systems along with six underground natural gas storage entities and an LNG terminalling facility. Our pipeline operations also include access between our U.S. based systems and Canada and Mexico as well as interests in three operating natural gas transmission systems in Australia.

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., Production has onshore and coal seam operations and properties in 16 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. Field Services' assets include 23 processing plants and related gathering facilities located in the south Texas, Louisiana, Mid-Continent and Rocky Mountain regions, as well as our interest in El Paso Energy Partners.

Our Merchant Energy segment consists of three primary divisions: global power, petroleum and energy trading. 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 88 power plants in 18 countries.

We use EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: equity earnings from unconsolidated investments, minority interests on consolidated, but less than wholly-owned operating subsidiaries and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense and returns on preferred interest of consolidated subsidiaries, income taxes, discontinued operations, extraordinary items and the impact of accounting changes. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow. The following are our segment results as of and for the year ended December 31:

	Segments As of or for the Year Ended December 31, 2002					
	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other[1]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,382	$ 432	$1,145	$ 6,796[2]	$ 43	$10,798
Foreign	3	71	3	1,319[2]	—	1,396
Intersegment revenue	220	1,623	881	(2,525)[2]	(199)	—
Restructuring and merger-related costs	1	—	1	29	50	81
(Gain) loss on long-lived assets	(13)	3	(179)	301	170	282
Western Energy Settlement	412	—	—	487	—	899
Ceiling test charges	—	269	—	—	—	269
Depreciation, depletion and amortization	374	773	56	129	73	1,405
Operating income (loss)	$ 790	$ 529	$ 271	$(1,336)	$ (326)	$ (72)
Earnings (losses) from unconsolidated affiliates	(2)	7	18	(264)	7	(234)
Minority interests in consolidated subsidiaries	—	—	(5)	(53)	—	(58)
Other income	33	1	3	108	103	248
Other expense	(3)	(3)	—	(93)	(10)	(109)
EBIT	$ 818	$ 534	$ 287	$(1,638)	$ (226)	$ (225)
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (124)	$ (124)
Cumulative effect of accounting change, net of income taxes	79	—	—	(133)	—	(54)
Assets						
Domestic	14,743	7,354	2,666	11,232	4,135[3]	40,130
Foreign	59	703	14	5,076	242	6,094
Capital expenditures and investments in unconsolidated affiliates	1,074	2,301	187	475	2	4,039
Total investments in unconsolidated affiliates	1,059	87	875	2,863	23	4,907

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) Includes $106 million of assets that are classified as discontinued operations.

	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other[1]	Total
	Segments As of or for the Year Ended December 31, 2001 (In millions)					
Revenue from external customers						
Domestic	$ 2,451	$ 199	$1,809	$ 7,833[2]	$ 379	$12,671
Foreign	2	46	4	926[2]	—	978
Intersegment revenue	295	2,102[3]	740	(2,684)[2]	(453)	—
Merger-related costs	291	47	46	44	1,092	1,520
(Gain) loss on long-lived assets	21	16	—	127	19	183
Ceiling test charges	—	135	—	—	—	135
Depreciation, depletion, and amortization	383	678	111	108	47	1,327
Operating income (loss)	$ 886	$ 919	$ 124	$ 398	$(1,406)	$ 921
Earnings (losses) from unconsolidated affiliates	136	(1)	72	232	11	450
Minority interests in consolidated subsidiaries	(1)	—	—	(1)	—	(2)
Other income	28	3	3	308	54	396
Other expense	(11)	(1)	(4)	(33)	(87)	(136)
EBIT	$ 1,038	$ 920	$ 195	$ 904	$(1,428)	$ 1,629
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (5)	$ (5)
Extraordinary items, net of income taxes	(27)	—	(5)	(7)	65	26
Assets						
Domestic	14,345	7,584	3,564	11,005	4,343[4]	40,841
Foreign	98	874	17	6,684	32	7,705
Capital expenditures and investments in unconsolidated affiliates	1,093	2,521	165	1,111	967	5,857
Total investments in unconsolidated affiliates	1,104	77	554	3,543	19	5,297

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions and in 2001, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) The increase in intersegment revenue from 2000 to 2001 for our Production segment is primarily due to the consolidation of Engage in September 2000.

(4) Includes $352 million of assets that are classified as discontinued operations.

	Segments As of or for the Year Ended December 31, 2000					
	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other[1]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,521	$1,134	$1,307	$ 11,076[2]	$1,193	$ 17,231
Foreign	—	5	2	2,033[2]	—	2,040
Intersegment revenue	220	547	130	(109)[2]	(788)	—
Merger-related costs	—	—	—	—	93	93
(Gain) loss on long-lived assets	(7)	—	7	(6)	1	(5)
Depreciation, depletion, and amortization	376	611	76	100	68	1,231
Operating income (loss)	$ 1,150	$ 613	$ 166	$ 572	$ (86)	$ 2,415
Earnings from unconsolidated affiliates	149	—	47	231	1	428
Other income	27	—	2	148	57	234
Other expense	(3)	(4)	(1)	(21)	(28)	(57)
EBIT	$ 1,323	$ 609	$ 214	$ 930	$ (56)	$ 3,020
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (1)	$ (1)
Extraordinary items, net of income taxes	89	—	(19)	—	—	70
Assets						
Domestic	14,025	5,856	3,752	15,285	3,612[3]	42,530
Foreign	83	198	17	4,018	57	4,373
Capital expenditures and investments in unconsolidated affiliates	725	2,067	505	1,045	614	4,956
Total investments in unconsolidated affiliates	1,119	7	567	2,643	74	4,410

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) Includes $322 million of assets that are classified as discontinued operations.

The reconciliations of EBIT to income (loss) from continuing operation before extraordinary items and cumulative effect of accounting changes are presented below for each of the three years ended December 31:

	2002	2001	2000
	(In millions)		
Total EBIT for segments	$ (225)	$ 1,629	$ 3,020
Interest and debt expense	(1,400)	(1,156)	(1,040)
Returns on preferred interest of consolidated subsidiaries	(159)	(217)	(204)
Income tax	495	(184)	(539)
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(1,289)	$ 72	$ 1,237

We had no customers whose revenues exceeded 10 percent of our total revenues in 2002, 2001 and 2000.

25. Supplemental Cash Flow Information

The detail of our cash flow changes in working capital for the three years ending December 31 are as follows:

	2002	2001	2000
		(In millions)	
Working capital changes			
Accounts and notes receivable	$ (345)	$1,154	$(3,025)
Inventory	237	430	(148)
Change in trading price risk management activities, net	258	1,456	(1,373)
Accounts payable	(738)	(984)	2,144
Broker and other margins on deposit with others	(257)	88	(893)
Broker and other margins on deposit with us	(647)	210	936
Other working capital changes			
Assets	(18)	(635)	721
Liabilities	74	195	(696)
Total	$(1,436)	$1,914	$(2,334)

Our non-working capital and other cash flow changes for the three years ending December 31 are as follows:

	2002	2001	2000
		(In millions)	
Non-working capital changes and other			
Assets	$ (30)	$ (93)	$ (2)
Liabilities	(147)	(114)	(87)
Total	$ (177)	$ (207)	$ (89)

The following table contains supplemental cash flow information for the years ended December 31 for interest and taxes, which are reflected in working capital and non-working capital changes above:

	2002	2001	2000
		(In millions)	
Interest paid	$1,306	$1,402	$967
Income tax payments (refunds)	(105)	62	112

Detail of our short-term and long-term borrowings and repayments for the years ended December 31 is as follows:

	2002	2001	2000
		(In millions)	
Short-term borrowings and repayments			
Net repayments of commercial paper and short-term credit facilities	$ 154	$ (328)	$ (64)
Borrowings under credit facilities	—	245	455
Repayments on credit facilities	—	(700)	—
Repayments of notes payable	(94)	(3)	(82)
Total	$ 60	$ (786)	$ 309
Long-term borrowings and repayments			
Net proceeds from the issuance of notes payable	$ —	$ —	$ 58
Net proceeds from the issuance of long-term debt and other financing obligations	4,294	3,260	2,619
Payments to retire long-term debt and other financing obligations	(2,328)	(1,892)	(865)
Increase in notes payable to affiliates	4	521	1,207
Decrease in notes payable to affiliates	(513)	(612)	(600)
Total	$ 1,457	$ 1,277	$2,419

26. Investments in and Advances to Unconsolidated Affiliates

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 was greater than our equity in the net assets of these investments as of December 31, 2002 and 2001 by $223 million and $551 million. In 2002, the primary differences related to unamortized purchase price adjustments and asset impairment charges. In 2001, the primary differences related to unamortized purchase price adjustments, power contract restructurings and change in priority return on our investment in Chaparral and a financial guarantee for an international investment. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

	Type of Entity	Net Ownership Interest	Investments 2002	Investments 2001	Advances 2002	Advances 2001
		(Percent)	(In millions)			
Alliance Pipeline Limited Partnership[1]	LP[2]	2	$ 24	$ 160	$ —	$ —
Aux Sable Liquid[3]	LP[2]	14	—	58	—	—
Bastrop Company	LLC[4]	50	121	99	—	—
CE Generation[5]	LLC[4]	50	287	360	—	—
Chaparral Investors (Electron)[6]	LLC[4]	20	256	341	700	895
Citrus Corporation[7]		50	606	512	—	—
Eagle Point Cogeneration Partnership[8]	GP[9]	84	—	85	—	—
El Paso Energy Partners	LP[2]	—[10]	776	380	—	—
Great Lakes Gas Transmission[11]		50	312	297	—	—
Midland Cogeneration Venture[12]	LP[2]	44	316	276	—	—
Portland Natural Gas Transmission System	GP[9]	30	51	39	—	—
Other Domestic Investments[13]		various	391	542	67	40
Domestic			$3,140	$3,149	$767	$935

	Country	Type of Entity	Net Ownership Interest	Investments 2002	Investments 2001	Advances 2002	Advances 2001
			(Percent)	(In millions)			
Aguaytia Energy	Peru	LLC[4]	24	$ 52	$ 52	$ —	$ —
Bolivia to Brazil Pipeline	Bolivia/Brazil	LLC[4]	8	53	50	—	—
CAPSA/CAPEX[14]	Argentina	Corporation	—	—	259	—	—
Diamond Power (Gemstone)	Brazil	LLC[4]	50	663	555	25	—
EGE Fortuna	Panama	Corporation	25	61	56	—	—
EGE Itabo	Dominican Republic	Corporation	25	87	101	—	—
Enfield Power	United Kingdom	LP[2]	25	50	53	—	—
Gasoducto del Pacifico Pipeline (Argentina to Chile)	Argentina/Chile	Corporation	16	69	71	—	—
Habibullah Power	Pakistan	LLC[4]	50	57	53	99	—
Korea Independent Energy Corporation	Korea	Corporation	50	206	104	—	—
Meizhou Wan Generating	China	LLC[4]	25	56	76	—	—
Pescada	Brazil	LLC[4]	50	80	70	—	—
Saba Power Company	Pakistan	LLC[4]	94	55	48	—	—
Samalayuca[15]	Mexico	LLC[4]	50	22	103	—	—
Other Foreign Investments[13]	various		various	256	497	103	91
Foreign				$1,767	$2,148	$227	$ 91
Total investments in and advances to unconsolidated affiliates				$4,907	$5,297	$994	$1,026

(1) We sold 12.3 percent interest in November 2002, and we sold the remaining of 2.1 percent interest in March 2003.
(2) LP represents Limited Partnership.
(3) We sold 100 percent of our interest in November 2002.
(4) LLC represents Limited Liability Company.
(5) We sold 100 percent of our interest in January 2003.
(6) Mesquite Investors, LLC is included in Chaparral. We gave notice to our partner in March 2003 of our intent to exercise our option to purchase their interest. We anticipate the transaction will close in the second quarter of 2003.
(7) Citrus corporation owns 100 percent of Florida Gas Transmission System.
(8) Consolidated in January 2002.
(9) GP represents General Partnership.
(10) Our ownership interest consists of a one percent general partner interest, approximately 27 percent of the partnership's common units, all of the outstanding Series B preference units with $158 million liquidation value and all of the outstanding Series C units acquired for $350 million in November 2002.
(11) Includes a 46 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 4 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.
(12) Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.
(13) Denotes investments that are individually less than $50 million.
(14) Impaired in first quarter of 2002. Includes 45 percent of CAPSA, which owns 60 percent of CAPEX. This results in a 27 percent indirect ownership interest in CAPEX.
(15) We sold 100 percent of our interest in Samalayuca II power plant in December 2002.

Earnings from our unconsolidated affiliates are as follows for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
Aguaytia Energy	$ 3	$ 4	$ 1
Alliance Pipeline Limited Partnership[1]	21	23	12
Aux Sable Liquid	(3)	(4)	(2)
Bastrop Company, LLC	(5)	—	—
Bolivia to Brazil Pipeline	2	1	—
CAPSA/CAPEX	—	(12)	4
CE Generation[2]	22	29	35
Chaparral Investors (Electron)	(62)	75	(5)
Citrus Corporation	43	41	51
Diamond Power (Gemstone)	109	2	—
Eagle Point Cogeneration Partnership[3]	—	22	25
EGE Fortuna	5	3	7
EGE Itabo	(2)	5	9
El Paso Energy Partners	70	47	20
Enfield Power	(3)	18	2
Gasoducto del Pacifico Pipeline (Argentina to Chile)	(2)	2	1
Great Lakes Gas Transmission	63	55	52
Habibullah Power	10	2	9
Korea Independent Energy Corporation	24	20	—
Meizhou Wan Generating	(13)	—	—
Midland Cogeneration Venture	28	23	37
Pescada	6	(1)	—
Portland Natural Gas Transmission System	4	—	(1)
Saba Power Company	7	—	1
Samalayuca[4]	19	12	17
Other	47	129	117
Subtotal	393	496	392
Impairment charges and gains and losses on sale of investments	(627)	(46)	36
Total earnings (losses) from unconsolidated affiliates	$(234)	$450	$428

(1) We sold 12.3 percent interest in November 2002, and we sold the remaining of 2.1 percent interest in March 2003.
(2) Sold in first quarter of 2003.
(3) Consolidated in January 2002.
(4) We sold our interest in Samalayuca II power plant in December 2002.

Our impairment charges and gains and losses on sales of our investments during 2002, 2001 and 2000 consisted of the following:

Investment	Pre-tax Gain (Loss) (In millions)	Cause of Impairment
2002		
Aqua de Cajon	$ (24)	Weak economic conditions in Argentina
Aux Sable	(47)	Sale of investment
CAPSA/CAPEX	(262)	Weak economic conditions in Argentina
CE Generation	(74)	Sale of investment
EPIC Australia	(153)	Decision to discontinue further capital investment
PPN	(41)	Loss of economic fuel supply and payment default
Other investments	(26)	
Total 2002	$(627)	
2001		
East Asia Power	$ (39)	Weak economic conditions in the Philippines and a decision to discontinue further capital investment
Deepwater Investors	13	Sale of investment
Fife Power	(35)	Weak economic conditions in the U.K. power market and the decision to discontinue further capital investment
Other	15	
Total 2001	$ 46	
2000		
East Asia Power	$ 20	Sale of a portion of our investment
Guatemala Power	16	Sale of investment
Total 2000	$ 36	

Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. We received distributions and dividends of $256 million in 2002 and $241 million in 2001 from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $24 million and $38 million in 2002 and 2001 and total assets of $450 million and $766 million at December 31, 2002 and 2001.

	Year Ended December 31,		
	2002	2001	2000
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$2,881	$2,490	$5,134
Operating expenses	2,018	1,718	4,618
Income from continuing operations	426	449	335
Net income	450	473	352

	December 31, 2002	December 31, 2001
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 1,504	$ 1,350
Non-current assets	10,595	11,152
Short-term debt	929	406
Other current liabilities	856	788
Long-term debt	4,517	4,824
Other non-current liabilities	1,083	1,706
Minority interest	30	32
Equity in net assets	4,684	4,746

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

	2002	2001	2000
	(In millions)		
Operating revenue[1]	$237	$514	$1,341
Other revenue — management fees	192	150	82
Cost of sales[1]	268	175	289
Reimbursement for operating expenses	186	164	102
Other income	18	20	14
Interest income	30	45	23
Interest expense	42	50	49

(1) The decrease in 2001 affiliated revenue and cost of sales is due primarily to the consolidation of Engage in September 2000.

Chaparral

We entered into the Chaparral investment (also referred to as Electron) in 1999 to expand our domestic power generation business. Chaparral's corporate structure is a limited liability company that, at December 31, 2002, was owned approximately 20% by us and approximately 80% by an unaffiliated investor, Limestone. Limestone is capitalized by private equity contributions of $150 million from a group of unrelated financial investors through Credit Suisse First Boston Corporation and $1 billion of senior secured notes issued to institutional investors. Limestone is controlled by subsidiaries or affiliates of Credit Suisse First Boston Corporation.

In March 2003, we notified Limestone that we would exercise our right under the partnership agreements to purchase all of the outstanding third party equity in Limestone on May 31, 2003, for $175 million. Also in March 2003, we contributed $1 billion to Limestone in exchange for a non-controlling interest, which Limestone then used to pay off the Limestone notes which matured on March 17, 2003. Following our investment of $1 billion in Limestone, our effective ownership in Chaparral increased to approximately 90 percent. We continue to account for our investment in Chaparral under the equity method since we do not control Limestone, and therefore do not control Chaparral. We will, however, consolidate Chaparral upon the purchase of the remaining Limestone equity interest, which we anticipate will occur in May 2003. At that time, we will record the acquired assets and liabilities at their fair values. The fair value of assets and liabilities acquired will be impacted by changes in the unregulated power industry as a whole, as well as by changes in regional power prices in the U.S. Any excess of the proceeds paid over the fair value of net assets acquired will be reflected as goodwill. Goodwill is not amortized, but it will be tested for impairment.

Chaparral owns or has interests in approximately 34 power generation facilities. As of December 31, 2002, Chaparral had $4.2 billion of total assets and $1.8 billion of consolidated third party debt. Chaparral's debt is related to specific projects it owns or has interests in, and is recourse solely to those projects.

We have entered into various financing transactions with Chaparral and its subsidiaries each year, which include capital contributions, debt issuances and advances.

The following table summarizes the presentation of these transactions on our balance sheet at December 31 (in millions):

	2002	2001
Debt securities payable	$ (79)	$(169)
Notes receivable	323	343
Credit facility receivable	377	552
Contingent interest promissory notes payable	(173)	(289)
Subtotal	448	437
Equity investment	256	341
Net investment	$ 704	$ 778

The debt securities, notes payable and receivable, revolving credit facility, and contingent interest promissory notes are included in current and long-term receivables and payables from affiliates, as appropriate, with the related interest as interest income or expense in our income statement.

The debt securities payable to Chaparral are payable on demand and carry a fixed interest rate of 7.443%. The notes payable and receivable from Chaparral are payable on demand and carry various fixed interest rates. The credit facility was established in 1999 and allows Chaparral to borrow up to $925 million from us at a variable interest rate, which was 1.94%, 2.64% and 7.32% at December 31, 2002, 2001 and 2000.

The contingent interest promissory notes carry a variable interest rate not to exceed 12.75%, which was 10.0%, 11.0% and 10.9% at December 31, 2002, 2001 and 2000, and mature in 2019 through 2021. The interest payments are contingent on cash flow distributions from five power plant investments we own. If we sell these investments, the maturity date of the notes may be accelerated.

Chaparral has used our funds and the funds contributed by Limestone to acquire the domestic power generation and related businesses described above. In some cases, Chaparral acquired these power generation assets from us. Chaparral did not acquire any power generation assets from us in 2002. Chaparral acquired power generation assets from us with a value of $276 million in 2001, which we determined to be a fair and reasonable amount. We did not recognize any gains or losses on those transactions.

In addition to the financing transactions described above, we have also entered into various contractual agreements with Chaparral related to management and trading activities.

We serve as manager of Chaparral under a management agreement that expires in 2006. We are compensated for the services we provide through an annual management fee, which has performance based and fixed components. The performance fee was determined based on how well we performed as manager of Chaparral, and was determined by evaluating the changes in the value of the portfolio of power assets held by Chaparral. Our management fee is evaluated for reasonableness and is subject to the approval of our joint venture partner annually. In 2002 and 2001, the management fee was $205 million and $167 million, consisting of a $185 million and $147 million performance fee recorded in operating revenues plus a $20 million annual fixed fee in both years recorded as a reimbursement of operating expenses. We do not expect to earn a performance-based management fee or receive a cost reimbursement fee from Chaparral in 2003. In addition, we have administrative services agreements with many of the power plants in the Chaparral structure. We recorded approximately $104 million, $95 million, and $47 million in 2002, 2001, and 2000 as a reimbursement of operating expenses under these agreements.

We also enter into various contractual agreements with Chaparral and its operating subsidiaries in conjunction with Chaparral's operations. These include agreements to (i) supply natural gas or other fuels to power Chaparral's facilities; (ii) purchase all or a portion of the power produced by Chaparral's facilities; (iii) provide some or all of the power supply that Chaparral is obligated to provide to fulfill agreements it has with third parties; (iv) purchase tolling rights; and (v) provide other services to Chaparral related to its operations. We recognized revenues of $65 million and $243 million in 2002 and 2001 related to these transactions. These activities are accounted for under both the accrual method and the mark-to-market method of accounting, depending on the contract.

Gemstone

We entered into the Gemstone investment in 2001 to finance five major power plants in Brazil.

Gemstone is a generic term used to describe several entities. The first is the joint venture in which we have an equity investment named Diamond Power Ventures, LLC, (Diamond). Diamond is owned by us and a company called Gemstone Investor Limited (Gemstone Investor). Gemstone Investor is 100 percent owned by a subsidiary of Rabobank International, which, in addition to its $50 million equity investment, issued $950 million of senior secured notes to institutional investors. Gemstone Investor used the entire $1 billion to (a) invest up to $700 million in Diamond, and (b) purchase a $300 million preferred interest in a company called Topaz Power Ventures LLC (Topaz), our consolidated subsidiary. Topaz indirectly owns and operates two Brazilian power plants. We account for Gemstone Investor's preferred investment in Topaz as minority interest. We do not consolidate Diamond, which owns three power plants under development in Brazil.

Gemstone owns interests in five power generation facilities in Brazil with a total power generation capacity of 2,184 megawatts. As of December 31, 2002, Gemstone had total assets of $1.7 billion, including a $304 million investment in Topaz, which carries a preferred return of 8.03%, and $122 million in receivables from us, which carry a fixed interest rate of 5.25%. Our total investment in Gemstone at December 31, 2002, was $663 million, excluding the payables of $122 million and minority interest of $304 million mentioned above.

Our consolidated subsidiary, Gemstone Administracao Ltda, serves as the managing member of Diamond and provides management services to Diamond under a fixed-fee administrative services agreement that has an original term of ten years. The fixed fee reimburses us for legal, accounting and general and administrative expenses incurred on behalf of Diamond. This fee was not significant for 2002 or 2001.

The following summarizes our financial position with Gemstone at December 31 (in millions):

	2002	2001
Debt securities payable	$(122)	$(346)
Credit facility receivable	25	—
Subtotal	(97)	(346)
Equity investment	663	555
Net investment	$ 566	$ 209
Minority interest	$(304)	$(300)

We have a credit facility with Gemstone that allows Gemstone to borrow up to $300 million from us at a variable interest rate, which was 6.8% at December 31, 2002. Gemstone owed us $25 million under this facility as of December 31, 2002, and did not utilize this facility in 2001. We earned less than $1 million of interest income from this facility in 2002 and 2001.

Our investment in Gemstone as of December 31, 2002 and 2001, was $663 million and $555 million, and we account for our investment using the equity method of accounting since we do not have the ability to exercise control over the entity. The short-term notes we issued are included in short-term borrowings in our balance sheet, with the related interest as interest expense in our income statement. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement.

Under our management agreement with Gemstone, we earn a cost-based management fee. This fee was not significant in 2002 or 2001. We have also entered into a participation agreement with one of Gemstone's power generation interests whereby we earn a fee for managing, constructing, and operating the related facilities and marketing and distributing the energy produced by these facilities. This fee was not significant in 2002.

Rabobank, the third party investor in Gemstone, has the right to remove us as manager of Gemstone. In January 2003, Rabobank notified us that they planned to remove us as manager. We, in turn, notified Rabobank that we were exercising our right under the partnership agreements to purchase all of their $50 million equity in Gemstone. We will consolidate Gemstone upon the purchase of Rabobank's third party equity in Gemstone in April 2003, unless we replace them with a new partner.

Gemstone owns interests in five power generation facilities in Brazil with a total power generation capacity of 2,184 MW. Summarized financial position data for our unconsolidated affiliate in Gemstone, Diamond Power Ventures LLC, is as follows as of December 31:

	2002	2001
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 110	$ 22
Non-current assets	1,197	901
Short-term debt	—	—
Other current liabilities	46	17
Long-term debt	—	—
Other non-current liabilities	12	—
Members' equity	1,249	906

Citrus

We own 50 percent of Citrus Corp. Enron Corp. owns the other 50 percent. Citrus Corporation owns Florida Gas Transmission, a 4,804 mile regulated pipeline system that extends from producing regions in Texas to markets in Florida. Our investment in Citrus is limited to our ownership of the voting stock of Citrus, and we have no financial obligations, commitments or guarantees, either written or oral, to support Citrus. We have one commercial contract with Citrus under which we provide natural gas to the trading subsidiary of Citrus, and for which we are paid a fixed price.

The ownership agreements of Citrus provide each partner with a right of first refusal to purchase the ownership interest of the other partner. We have no obligations, either written or oral, to acquire Enron's ownership interest in Citrus in the event Enron must sell its interest as a result of its current bankruptcy proceedings.

Enron serves as the operator for Citrus. While Enron has filed for bankruptcy, there have been minimal changes in the operations and management of Citrus as a result of Enron's bankruptcy. Accordingly, Citrus has continued to operate as a jointly owned investment, over which we have significant influence, but not the ability to control.

Enron's bankruptcy has impacted the financial results of Citrus related to energy contracts between Citrus and Enron's energy trading subsidiary. During 2001, we established reserves of $6.9 million related to the Enron bankruptcy. During 2002, accounts receivable balances associated with contracts rejected by the bankruptcy court were classified as uncollectable. We applied the $6.9 million reserve amount against the outstanding accounts receivable balance. None of these charges are considered to be material to our financial statements.

El Paso Energy Partners

A subsidiary in our Field Services segment serves as the general partner of El Paso Energy Partners, a master limited partnership that has limited partnership units that trade on the New York Stock Exchange. We currently own 26.5 percent, or 11,674,245 of the partnership's common units and the one percent general partner interest. The remaining 73.5 percent of the common units of the limited partnership are owned by public unit holders (including small amounts owned by the general partner's management and employees), none of which exceeds a 10 percent ownership interest. In November 2002, as part of the proceeds from the sale of our San Juan Basin assets to El Paso Energy Partners, we received $350 million of Series C units, a new non-voting class of limited partnership units. The Series C units receive the same level of distributions as the common units and can be converted to common units. After April 30, 2003, we will have the right to request a vote of the common unitholders as to whether the Series C units should be converted into common units. If the common unitholders approve the conversion, then each Series C unit will convert into a common unit. If the common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate from time to time. Thereafter, the Series C unit distribution rate can increase to 110 percent of the common unit distribution rate on April 30, 2004, and to 115 percent of the common unit distribution rate on April 30, 2005. Also, in the third quarter of 2000, we received $170 million of Series B preference units in exchange for the sale of the natural gas storage businesses of Crystal Gas Storage, Inc., our wholly owned subsidiary, to El Paso Energy Partners. These preference units accrue dividends at a rate of 10% on a cumulative basis, and are redeemable at the option of El Paso Energy Partners. In October 2001, the partnership redeemed $50 million liquidation value of the Series B preference units we received in the Crystal transaction. At December 31, 2002, the liquidation value of the remaining Series B preference units was $158 million. A majority of the members of the Board of Directors governing El Paso Energy Partners is independent of us and its audit and conflicts committee and governance and compensation committee are completely comprised of independent board members.

As the general partner, Field Services manages the partnership's day-to-day operations and performs all of the partnership's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. El Paso Energy Partners contributes to our income through our general partner interest and our ownership of common and preference units. We do not have any loans to or from El Paso Energy Partners. In addition, except for a nominal guarantee of lease obligations on behalf of a subsidiary of El Paso Energy Partners, we have not provided any guarantees, either monetary or performance, on behalf of or for the benefit of El Paso Energy Partners nor do we have any other liabilities other than normal course of business as a result of or arising out of our role as the general partner or our ownership interest in El Paso Energy Partners. Our normal course of business transactions with El Paso Energy Partners include sales of natural gas and services, such as transportation and fractionation, storage, processing and other types of operational services. These activities are based on the same terms as our non-affiliates. Field Services recognized revenues of $1 million in 2002 and cost of sales of $97 million and $32 million in 2002 and 2001. Field Services was also reimbursed $59 million, $34 million and $22 million in 2002, 2001 and 2000 for expenses incurred on behalf of the partnership. In addition, Merchant Energy recognized revenues of $6 million, $28 million, and $14 million in 2002, 2001 and 2000, and cost of sales of $80 million, $16 million, and $22 million in 2002, 2001 and 2000.

In 2001, as a result of our merger with Coastal, El Paso Energy Partners sold its interest in several offshore assets including 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 $25 million. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by El Paso Energy Partners. These payments have been recorded as merger-related costs.

In April 2002 and November 2002, we sold midstream assets to El Paso Energy Partners for total consideration of $735 million and $766 million. See Note 3 for further discussion.

27. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				
	December 31	September 30	June 30	March 31	Total
	(In millions, except per common share amounts)				
2002[1]					
Operating revenues[2]	$ 2,796	$2,656	$2,987	$3,755	$12,194
Restructuring and merger-related costs	18	—	63	—	81
(Gain) loss on long-lived assets	311	1	(15)	(15)	282
Western Energy Settlement	899	—	—	—	899
Ceiling test charges	2	—	234	33	269
Operating income (loss)[3]	(1,519)	201	234	1,012	(72)
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(1,512)	(33)	8	248	(1,289)
Discontinued operations, net of income taxes	(2)	(36)	(67)	(19)	(124)
Cumulative effect of accounting changes, net of income taxes	(222)	—	14	154	(54)
Net income (loss)	(1,736)	(69)	(45)	383	(1,467)
Basic earnings per common share					
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (2.55)	$(0.06)	$ 0.02	$ 0.47	$ (2.30)
Discontinued operations, net of income taxes	—	(0.06)	(0.13)	(0.03)	(0.22)
Cumulative effect of accounting changes, net of income taxes	(0.37)	—	0.03	0.29	(0.10)
Net income (loss)	$ (2.92)	$(0.12)	$(0.08)	$ 0.73	$ (2.62)
Diluted earnings per common share					
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (2.55)	$(0.06)	$ 0.02	$ 0.46	$ (2.30)
Discontinued operations, net of income taxes	—	(0.06)	(0.13)	(0.03)	(0.22)
Cumulative effect of accounting changes, net of income taxes	(0.37)	—	0.03	0.29	(0.10)
Net income (loss)	$ (2.92)	$(0.12)	$(0.08)	$ 0.72	$ (2.62)

(1) Our coal mining operations are classified as discontinued operations. See Note 10 for further discussion.

(2) Our operating revenues differ from those previously reported in our March 31, 2002 Form 10-Q by $9,433 million due to income statement reclassifications associated with our adoption of EITF Issue No. 02-3, discontinued operations and other minor reclassifications, which had no impact on previously reported net income or stockholders' equity.

(3) Our operating income (loss) differs from that previously reported in our September 30, 2002, June 30, 2002 and March 31, 2002 Form 10-Q's by $10 million, $15 million and $387 million due to income statement reclassifications associated with our discontinued operations, reclassifications of gains and losses on asset sales and asset impairments to operating income and other minor reclassifications which had no impact on previously reported net income or stockholders' equity.

	Quarters Ended				
	December 31	September 30	June 30	March 31	Total
	(In millions, except per common share amounts)				
2001[1]					
Operating revenues[2]	$2,759	$3,166	$3,757	$3,967	$13,649
Merger-related costs	(7)	27	489	1,011	1,520
Loss on long-lived assets	19	7	4	153	183
Ceiling test charges	—	135	—	—	135
Operating income (loss)[3]	596	477	65	(217)	921
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	379	215	(131)	(391)	72
Discontinued operations, net of income taxes	(4)	1	(3)	1	(5)
Extraordinary items, net of income taxes	—	(5)	41	(10)	26
Net income (loss)	375	211	(93)	(400)	93
Basic earnings per common share					
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.75	$ 0.43	$(0.26)	$(0.78)	$ 0.14
Discontinued operations, net of income taxes	(0.01)	—	—	—	(0.01)
Extraordinary items, net of income taxes	—	(0.01)	0.08	(0.02)	0.05
Net income (loss)	$ 0.74	$ 0.42	$(0.18)	$(0.80)	$ 0.18
Diluted earnings per common share					
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.73	$ 0.42	$(0.26)	$(0.78)	$ 0.14
Discontinued operations, net of income taxes	(0.01)	—	—	—	(0.01)
Extraordinary items, net of income taxes	—	(0.01)	0.08	(0.02)	0.05
Net income (loss)	$ 0.72	$ 0.41	$(0.18)	$(0.80)	$ 0.18

(1) Our coal mining operations are classified as discontinued operations. See Note 10 for further discussion.

(2) Our operating revenues differ from those previously reported in our September 30, 2001, June 30, 2001, and March 31, 2001 Form 10-Q's by $10,679 million, $9,606 million and $13,787 million due to income statement reclassifications associated with our adoption of EITF Issue No. 02-3, discontinued operations and other minor reclassifications, which had no impact on previously reported net income or stockholders' equity.

(3) Our operating income (loss) differs from that previously reported in our September 30, 2001, June 30, 2001, and March 31, 2001 Form 10-Q's by $3 million, $141 million and $4 million due to income statement reclassifications associated with our discontinued operations, reclassification of gains and losses on asset sales and asset impairments to operating income and other minor reclassifications, which had no impact on previously reported net income or stockholders' equity.

28. Supplemental Natural Gas and Oil Operations (Unaudited)

At December 31, 2002, we had interests in natural gas and oil properties in 16 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have a limited number of natural gas and oil properties in Brazil, Canada, Hungary and Indonesia. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

For purposes of the Supplemental Natural Gas and Oil Operations disclosure, we have presented reserves, standardized measure of discounted future net cash flows and the related changes in standardized measure separately for natural gas systems operations which includes the regulated natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002. The Supplemental Natural Gas and Oil Operations disclosure does not include any value for natural gas systems storage gas and liquids volumes managed by our Pipelines segment.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide
2002				
Natural gas and oil properties:				
Costs subject to amortization	$13,283	$608	$ 92	$13,983
Costs not subject to amortization	594	177	103	874
	13,877	785	195	14,857
Less accumulated depreciation, depletion and amortization	7,002	435	44	7,481
Net capitalized costs	$ 6,875	$350	$151	$ 7,376
2001				
Natural gas and oil properties:				
Costs subject to amortization	$12,933	$415	$ 72	$13,420
Costs not subject to amortization	629	250	49	928
	13,562	665	121	14,348
Less accumulated depreciation, depletion and amortization	6,956	170	31	7,157
Net capitalized costs	$ 6,606	$495	$ 90	$ 7,191

(1) Includes international operations in Brazil, Hungary and Indonesia.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide
2002				
Property acquisition costs				
Proved properties	$ 362	$ 6	$—	$ 368
Unproved properties	29	7	10	46
Exploration costs	246	70	45	361
Development costs	1,520	80	3	1,603
Total costs incurred	$2,157	$163	$58	$2,378
2001				
Property acquisition costs				
Proved properties	$ 91	$232	$—	$ 323
Unproved properties	44	16	25	85
Exploration costs	177	19	58	254
Development costs	1,529	105	14	1,648
Total costs incurred	$1,841	$372	$97	$2,310
2000				
Property acquisition costs				
Proved properties	$ 201	$ 3	$—	$ 204
Unproved properties	171	6	—	177
Exploration costs	290	42	11	343
Development costs	1,229	69	—	1,298
Total costs incurred	$1,891	$120	$11	$2,022

(1) Includes international operations in Brazil, Hungary and Indonesia.

Per our January 1, 2003 reserve report, the amounts estimated to be spent in 2003, 2004 and 2005 to develop our worldwide booked proved undeveloped reserves are $570 million, $483 million and $178 million.

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, 2002, pending determination of proved reserves.

Capitalized interest of $16 million, $18 million, and $7 million for the years ended December 31, 2002, 2001 and 2000 is included in the presentation below (in millions):

	Cumulative Balance December 31, 2002	Costs Excluded for Years Ended December 31, 2002	2001	2000	Cumulative Balance December 31, 1999
Worldwide[(1)]					
Acquisition	$406	$108	$149	$ 94	$55
Exploration	255	177	33	36	9
Development	213	69	95	26	23
	$874	$354	$277	$156	$87

(1) Includes operations in the United States, Brazil, Canada, Hungary and Indonesia.

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 2003 through 2006. Total amortization expense per Mcfe, including ceiling test charges, was $1.71, $1.22, and $1.00 in 2002, 2001, and 2000. Excluding ceiling test charges, amortization expense would have been $1.31, $1.04 and $1.00 per Mcfe in 2002, 2001, and 2000. Depreciation, depletion, and amortization excludes provisions for the impairment of international projects of $15 million in 2000.

All of our proved properties, with the exception of the proved reserves in Brazil, Hungary and Indonesia, are located in North America (U.S. and Canada).

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves are presented below. Information in this table is based on the reserve report dated January 1, 2003, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 465,783 MMcfe of production delivery commitments under financing arrangements that extend through 2042. The financing arrangement supported by these reserves matures in 2006. Total proved reserves on the fields with this dedicated production were 919,265 MMcfe. In addition, this table excludes the following equity interests: Production's interest in UnoPaso (Pescada in Brazil); Merchant Energy's interests in Sengkang in Indonesia; CAPSA and CAPEX in Argentina and Aguaytia in Peru; interest in El Paso Energy Partners. Combined proved natural gas reserves balances for these equity interests were 435,713 MMcf, liquids reserves were 39,693 MBbls, and natural gas equivalents were 673,871 MMcfe, all net to our ownership interests.

	Natural Gas (in Bcf) United States	Canada	Other Countries[(1)]	Worldwide	Natural Gas Systems[(2)]
Net proved developed and undeveloped reserves[(3)]					
January 1, 2000	4,540	73	—	4,613	198
Revisions of previous estimates	(249)	(62)	—	(311)	11
Extensions, discoveries and other	1,239	155	91	1,485	—
Purchases of reserves in place	577	2	—	579	—
Sales of reserves in place	(19)	—	—	(19)	—
Production	(516)	(1)	—	(517)	(33)

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

(3) 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.

	Natural Gas (in Bcf)				
	United States	Canada	Other Countries[1]	Worldwide	Natural Gas Systems[2]
December 31, 2000	5,572	167	91	5,830	176
Revisions of previous estimates	(874)	(136)	(51)	(1,061)	42
Extensions, discoveries and other	1,244	85	—	1,329	—
Purchases of reserves in place	116	83	—	199	—
Sales of reserves in place	(46)	—	—	(46)	—
Production	(552)	(13)	—	(565)	(35)
December 31, 2001	5,460	186	40	5,686	183
Revisions of previous estimates	(392)	(70)	31	(431)	—
Extensions, discoveries and other	766	56	5	827	—
Purchases of reserves in place	513	5	—	518	—
Sales of reserves in place	(1,664)	(30)	—	(1,694)	(183)
Production	(470)	(17)	—	(487)	—
December 31, 2002	4,213	130	76	4,419	—
Proved developed reserves					
December 31, 2000	2,877	112	—	2,989	176
December 31, 2001	2,967	138	—	3,105	183
December 31, 2002	2,684	104	—	2,788	—

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

	Liquids[1] (in MBbls)				
	United States	Canada	Other Countries[2]	Worldwide	Natural Gas Systems[3]
Net proved developed and undeveloped reserves[4]					
January 1, 2000	87,316	867	—	88,183	249
Revisions of previous estimates	(576)	(544)	—	(1,120)	7
Extensions, discoveries and other	13,196	3,600	4,862	21,658	—
Purchases of reserves in place	7,589	13	—	7,602	—
Sales of reserves in place	(609)	—	—	(609)	—
Production	(11,614)	(13)	—	(11,627)	(25)
December 31, 2000	95,302	3,923	4,862	104,087	231
Revisions of previous estimates	26,085	(4,224)	(4,862)	16,999	(118)
Extensions, discoveries and other	38,536	1,173	7,771	47,480	—
Purchases of reserves in place	132	10,570	—	10,702	—
Sales of reserves in place	(71)	—	—	(71)	—
Production	(13,821)	(560)	—	(14,381)	(16)
December 31, 2001	146,163	10,882	7,771	164,816	97
Revisions of previous estimates	(13,496)	(1,798)	(5,660)	(20,954)	—
Extensions, discoveries and other	17,567	282	10,541	28,390	—
Purchases of reserves in place	1,521	362	—	1,883	—
Sales of reserves in place	(18,566)	(2,535)	—	(21,101)	(97)
Production	(16,460)	(1,053)	—	(17,513)	—
December 31, 2002	116,729	6,140	12,652	135,521	—

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

(2) Includes international operations in Brazil, Hungary and Indonesia.

(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

(4) 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.

	Liquids[1] (in MBbls)				
	United States	Canada	Other Countries[2]	Worldwide	Natural Gas Systems[3]
Proved developed reserves					
December 31, 2000	55,044	2,723	—	57,767	231
December 31, 2001	92,060	7,341	—	99,401	97
December 31, 2002	70,805	4,445	—	75,250	—

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

(2) Includes international operations in Brazil, Hungary and Indonesia.

(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

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, 2002.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide
2002				
Net Revenues				
Sales to external customers	$ 339	$ 47	$ —	$ 386
Affiliated sales	1,595	20	—	1,615
Total	1,934	67	—	2,001
Production costs[2]	(284)	(18)	(1)	(303)
Depreciation, depletion and amortization	(748)	(28)	—	(776)
Ceiling test charges	—	(226)	(10)	(236)
	902	(205)	(11)	686
Income tax (expense) benefit	(307)	83	4	(220)
Results of operations from producing activities	$ 595	$ (122)	$ (7)	$ 466
2001				
Net Revenues				
Sales to external customers	$ 139	$ 45	$ —	$ 184
Affiliated sales	2,259	1	—	2,260
Total	2,398	46	—	2,444
Production costs[2]	(323)	(12)	—	(335)
Depreciation, depletion and amortization	(660)	(17)	—	(677)
Ceiling test charges	—	(87)	(28)	(115)
	1,415	(70)	(28)	1,317
Income tax (expense) benefit	(490)	25	(9)	(474)
Results of operations from producing activities	$ 925	$ (45)	$ (37)	$ 843

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

	United States	Canada	Other Countries[1]	Worldwide
2000				
Net Revenues				
Sales to external customers	$ 1,165	$ 6	$ —	$ 1,171
Affiliated sales	438	—	—	438
Total	1,603	6	—	1,609
Production costs[2]	(310)	(1)	—	(311)
Depreciation, depletion and amortization	(584)	(1)	—	(585)
	709	4	—	713
Income tax expense	(237)	(2)	—	(239)
Results of operations from producing activities	$ 472	$ 2	$ —	$ 474

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide	Natural Gas Systems[2]
2002					
Future cash inflows[3]	$ 21,948	$ 671	$ 542	$ 23,161	$ —
Future production costs	(3,822)	(127)	(124)	(4,073)	—
Future development costs	(1,922)	(16)	(133)	(2,071)	—
Future income tax expenses	(4,541)	(21)	(50)	(4,612)	—
Future net cash flows	11,663	507	235	12,405	—
10% annual discount for estimated timing of cash flows	(4,969)	(220)	(127)	(5,316)	—
Standardized measure of discounted future net cash flows	$ 6,694	$ 287	$ 108	$ 7,089	$ —
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 6,310	$ 287	$ 108	$ 6,705	$ —

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

(3) Excludes $708 million of future net cash outflows attributable to hedging activities.

	United States	Canada	Other Countries[1]	Worldwide	Natural Gas Systems[2]
2001					
Future cash inflows[3]	$ 15,832	$ 641	$ 253	$ 16,726	$ 313
Future production costs	(3,284)	(196)	(51)	(3,531)	(34)
Future development costs	(2,067)	(83)	(73)	(2,223)	(30)
Future income tax expenses	(2,228)	(8)	(23)	(2,259)	(83)
Future net cash flows	8,253	354	106	8,713	166
10% annual discount for estimated timing of cash flows	(3,453)	(143)	(52)	(3,648)	(72)
Standardized measure of discounted future net cash flows	$ 4,800	$ 211	$ 54	$ 5,065	$ 94
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 5,369	$ 211	$ 54	$ 5,634	$ 94
2000					
Future cash inflow[4]	$ 44,459	$1,597	$ 397	$ 46,453	$ 474
Future production costs	(5,451)	(136)	(70)	(5,657)	(59)
Future development costs	(1,743)	(35)	(139)	(1,917)	(51)
Future income tax expenses	(11,885)	(599)	(60)	(12,544)	(116)
Future net cash flows	25,380	827	128	26,335	248
10% annual discount for estimated timing of cash flows	(10,392)	(469)	(109)	(10,970)	(89)
Standardized measure of discounted future net cash flows	$ 14,988	$ 358	$ 19	$ 15,365	$ 159
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 13,839	$ 358	$ 19	$ 14,216	$ 159

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

(3) Excludes $973 million of future net cash inflows attributable to hedging activities.

(4) Excludes $1,995 million of future net cash outflows attributable to hedging activities.

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.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions, capital availability and corporate investment criteria.

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

	Years Ended December 31,[1]				
	2002	2001		2000	
	Exploration and Production[2]	Exploration and Production	Natural Gas Systems[3]	Exploration and Production	Natural Gas Systems
Sales and transfers of natural gas and oil produced net of production costs	$(1,697)	$ (2,108)	$(255)	$(1,748)	$(52)
Net changes in prices and production costs	6,524	(16,115)	10	12,095	150
Extensions, discoveries and improved recovery, less related costs	1,660	1,338	—	5,938	—
Changes in estimated future development costs	(199)	(17)	13	(422)	—
Previously estimated development costs incurred during the period	499	503	—	263	—
Revisions of previous quantity estimates	(1,139)	(866)	39	(976)	34
Accretion of discount	613	2,208	23	347	4
Net change in income taxes	(1,413)	5,642	25	(6,009)	(42)
Purchases of reserves in place	1,015	232	—	1,735	—
Sales of reserves in place	(3,328)	16	—	(14)	—
Change in production rates, timing and other	(511)	(1,133)	80	151	—
Net change	$ 2,024	$(10,300)	$ (65)	$11,360	$ 94

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

(2) Includes operations in the United States, Canada, Brazil, Hungary and Indonesia.

(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, based upon our audits and the report of other auditors, the consolidated financial statements listed in the Index under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso Corporation and its subsidiaries (the "Company") at December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, based on our audits and the report of other auditors, the financial statement schedule listed in the Index under Item 15(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 financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. The consolidated financial statements and financial statement schedule give retroactive effect to the merger of El Paso CGP Company (formerly The Coastal Corporation) on January 29, 2001 in a transaction accounted for as a pooling of interests, as described in Note 3 to the consolidated financial statements. We did not audit the financial statements and financial statement schedule of El Paso CGP Company as of December 31, 2000 and for the year then ended, which statements reflect total revenues of $26,936 million for the year ended December 31, 2000. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for El Paso CGP Company as of December 31, 2000 and for the year then ended, is based solely on the report of the other auditors. 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 and the report of other auditors provide a reasonable basis for our opinion.

As discussed in Notes 1 and 6, the Company adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* and Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* in the second quarter of 2002, and EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 1 and 2*, in the third and fourth quarter of 2002; respectively.

As described in Notes 1 and 13, the Company adopted Statement of Financial Accounting Standards, No. 133, *Accounting for Derivatives and Hedging Activities*, on January 1, 2001.

/s/ PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 28, 2003

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
El Paso CGP Company
Houston, Texas

We have audited the consolidated statements of income, stockholders' equity, cash flows and comprehensive income of El Paso CGP Company (formerly The Coastal Corporation) and subsidiaries, for the year ended December 31, 2000 (not presented separately herein). Our audit also included the El Paso CGP schedule of valuation and qualifying accounts (not presented separately herein). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, El Paso CGP Company's results of operations and cash flows for the year ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 19, 2001
(March 28, 2003 as to the effects of reclassifications related to the adoption of net reporting for trading activities and discontinued operations as discussed in notes 1 and 9, respectively)

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2002, 2001 and 2000
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2002					
Allowance for doubtful accounts	$130	$ 36	$ 43	$(17)	$ 192
Valuation allowance on deferred tax assets	3	36	—	(2)	37
Legal reserves	179	956 (1)	2	(97) (2)	1,040
Environmental reserves	565	2	(15)	(70) (3)	482
Regulatory reserves	34	48	1	(59) (4)	24
Planned major maintenance accrual	36	20	—	(16)	40
2001					
Allowance for doubtful accounts	$ 57	$ 81	$ (1)	$ (7) (5)	$ 130
Valuation allowance on deferred tax assets	3	—	—	—	3
Legal reserves	268	66	(124) (6)	(31)	179
Environmental reserves	318	247 (7)	30	(30)	565
Regulatory reserves	48	(1)	(11)	(2)	34
Planned major maintenance accrual	51	(1) (8)	—	(14)	36
2000					
Allowance for doubtful accounts	$ 65	$ 18	$ (19)	$ (7) (5)	$ 57
Valuation allowance on deferred tax assets	6	—	—	(3)	3
Legal reserves	73	(10)	210 (9)	(5)	268
Environmental reserves	295	56	1	(34)	318
Regulatory reserves	95	(2)	—	(45)	48
Planned major maintenance accrual	34	33	—	(16)	51

(1) Relates to our Western Energy Settlement of $899 million.
(2) Payments for various litigation reserves.
(3) Payments for various environmental remediation reserves.
(4) Payments for revenue crediting and rate settlement reserves.
(5) Primarily accounts written off.
(6) In 2001, we finalized our purchase price adjustment for the legal reserves related to our PG&E acquisition.
(7) Of this amount, $232 million relates to additional environmental remediation liabilities recorded in connection with the events described in Note 20.
(8) We accrued $23 million in 2001 and reversed $24 million of reserves for the Corpus Christi refinery leased to Valero in June.
(9) Of this amount, $53 million was the legal reserve we acquired in connection with our purchase of PG&E's Texas Midstream operations. We recorded an additional $159 million for legal reserves related to purchase price adjustments on our PG&E acquisition.

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 2003 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

As a result of recent clarifications in the insider trading rules, and in particular, the promulgation of Rule 10b5-1, we have revised our insider trading policy to allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of inside information at the time of the trade to execute pre-established trades of our securities for the officer or director according to fixed parameters. As of March 26, 2003, no officer or director has a current trading plan. However, we intend to disclose the existence of any trading plan in compliance with Rule 10b5-1 in future filings with the Securities and Exchange Commission.

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in our proxy statement for the 2003 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" in our proxy statement for the 2003 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

We own a one percent general partner interest in El Paso Energy Partners, a publicly traded master limited partnership and 26.5 percent of the partnership's common units. In addition, we own preferred units with $158 million liquidation value as of December 31, 2002, and all of its outstanding Series C units acquired for $350 million in November 2002. Some of our directors, officers and other personnel who provide services for us also provide services for El Paso Energy Partners. These shared personnel own and are awarded units, or options to purchase units, in El Paso Energy Partners from time to time, and their personal financial interests may not always be completely aligned with ours.

A discussion of agreements, arrangements and transactions between us and El Paso Energy Partners is summarized in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, under the heading "Field Services". Also see Part II, Item 8, Financial Statements and Supplementary Data, Note 26.

Information appearing under the caption "Certain Relationships and Related Transactions" in our proxy statement for the 2003 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls (Internal Controls) within 90 days of the filing date of this annual report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. El Paso's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Annual Report. The principal executive officer and principal financial officer note that, from the date of the controls evaluation to the date of this Annual Report, there have been no significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that, subject to the limitations discussed above, the Disclosure Controls are effective to ensure that material information relating to El Paso and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, particularly during the period when our periodic reports are being prepared.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included herein, or as Exhibits to this Annual Report, as appropriate.

PART IV

ITEM 15. 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:

Date	Event Reported
October 9, 2002	Updated information for our sale of the San Juan midstream assets to El Paso Energy Partners.
October 9, 2002	Updated 5-year historical selected financial data for discontinued operations and the adoption of new accounting standards.
October 9, 2002	Filed our Computation of Ratio of Earnings to Fixed Charges for five years ended December 31, 2001, and the six months ended June 30, 2002 and 2001.
October 31, 2002	Announced the assignment of Snøhvit Supply Contract and Cove Point LNG Capacity to Statoil ASA.
November 27, 2002	Responded to a Ratings Action by Moody's Investors Service and reiterated our strong liquidity position.
December 13, 2002	Corrected an exhibit filed with our 2002 Third Quarter Form 10-Q.
December 23, 2002	Updated our liquidity position, asset sales program and business plans.
January 8, 2003	Filed our Computation of Ratio of Earnings to Fixed Charges for five years ended December 31, 2001 and the nine months ended September 30, 2002.
January 9, 2003	Updated information for our sale of the San Juan midstream assets to El Paso Energy Partners.
February 5, 2003	Announced our 2003 Operational and Financial Plan.
February 10, 2003	Provided additional information on our 2003 Operational and Financial Plan.
February 11, 2003	Announced our CEO Transition Plan.
February 12, 2003	Responded to Moody's Investors Service downgrade.
February 13, 2003	Prepared comments on liquidity by our Chief Executive Officer at the UBS Warburg Energy Conference.
February 18, 2003	Requested that our shareholders reject Selim Zilkha's proposal to be brought before the 2003 Annual Meeting.
February 25, 2003	Announced continued progress on the execution of our 2003 Operational and Financial Plan.
March 3, 2003	Information concerning the private offerings of ANR Pipeline Company and Southern Natural Gas Company.
March 13, 2003	Announced that Ronald L. Kuehn, Jr. will become Chief Executive Officer and Chairman of the El Paso Board of Directors effective March 13, 2003.
March 13, 2003	Announced the completion of a $1.2 billion financing and a $500 million asset sale.
March 13, 2003	Announced that John L. Whitmire will join the El Paso Board of Directors effective March 17, 2003.
March 18, 2003	Announced the retirement of $1 billion of notes associated with the Limestone Trust financing.
March 21, 2003	Announced that an Agreement in Principle had been reached with respect to the Western energy crisis.
March 28, 2003	Announced that J. Michael Talbert will join the El Paso Board of Directors effective April 1, 2003, and that John Bissell has been named Lead Director.
March 31, 2003	Announced earnings results for 2003.

We also furnished information to the SEC in Item 9 Current Reports on Form 8-K. Item 9 Current Reports on Form 8-K are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section, but are furnished to comply with Regulation FD.

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2002

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
3.A	Restated Certificate of Incorporation of El Paso, as filed with the Delaware Secretary of State on February 7, 2001 as amended on May 23, 2002 (Exhibit 3.A to our Registration Statement on Form 8/A filed June 19, 2002).
*3.B	By-Laws of El Paso effective as of December 31, 2002.
4.B.1	Certificate of Elimination and Retirement of Series B Mandatorily Convertible Single Reset Preferred Stock and Series C Mandatorily Convertible Single Reset Preferred Stock as filed with the Delaware Secretary of State on May 23, 2002 (Exhibit 4.B to our Registration Statement on Form 8/A filed June 19, 2002).
*4.B.2	Certificate of Elimination and Retirement of Series B Mandatory Convertible Single Reset Preferred Stock as filed with the Delaware Secretary of State on January 30, 2003.
4.D	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank, USA (as successor to JPMorgan Chase Bank, formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to our Form 8-K dated May 10, 1999); Seventh Supplemental Indenture dated as of June 10, 2002, by and between El Paso and HSBC Bank, USA (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.2 to our Registration Statement on Form S-4 filed July 17, 2002; Eighth Supplemental Indenture dated as of June 26, 2002, between El Paso and HSBC Bank, USA (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.A to our Form 8-K filed June 26, 2002).
4.E	Purchase Contract Agreement (including forms of Units and Stripped Units), dated as of June 26, 2002, between El Paso and JPMorgan Chase Bank, as Purchase Contract Agent (Exhibit 4.B to our Form 8-K filed June 26, 2002).
4.F	Registration Rights Agreement dated as of June 10, 2002, between El Paso and Credit Suisse First Boston Corporation (Exhibit 4.3 to our Registration Statement on Form S-4 filed July 17, 2002).
4.G	Pledge Agreement, dated as of June 26, 2002, among El Paso, The Bank of New York, as Collateral Agent, Custodial Agent and Securities Intermediary, and JPMorgan Chase Bank, as Purchase Contract Agent (Exhibit 4.C to our Form 8-K filed June 26, 2002).
4.H	Remarketing Agreement, dated as of June 26, 2002, among El Paso, JPMorgan Chase Bank, as Purchase Contract Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent (Exhibit 4.D to our Form 8-K filed June 26, 2002).
10.A	$3,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement, dated May 15, 2002, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties thereto, JPMorgan Chase Bank, as Administrative Agent and CAF Advance Agent, ABN Amro Bank N.V. and Citibank, N.A., as Co-Documentation Agents, and Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A to our 2002 Second Quarter Form 10-Q).

Exhibit Number	Description
10.B	$1,000,000,000 Amended and Restated 3-Year Revolving Credit and Competitive Advance Facility Agreement dated June 27, 2002, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties thereto, JPMorgan Chase Bank, as Administrative Agent, CAF Advance Agent and Issuing Bank, Citibank, N.A. and ABN Amro Bank N.V., as Co-Documentation Agents, and Bank of America, N.A., as Syndication Agent (Exhibit 10.B to our 2002 Second Quarter Form 10-Q).
+10.C	Omnibus Compensation Plan dated January 1, 1992; Amendment No. 1 effective as of April 1, 1998 to the Omnibus Compensation Plan; Amendment No. 2 effective as of August 1, 1998 to the Omnibus Compensation Plan; Amendment No. 3 effective as of December 3, 1998 to the Omnibus Compensation Plan; and Amendment No. 4 effective as of January 20, 1999 to the Omnibus Compensation Plan (Exhibit 10.C to our 1998 10-K); Amendment No. 5 effective as of August 1, 2001 to the Omnibus Compensation Plan (Exhibit 10.C.1 to our 2001 Third Quarter Form 10-Q).
+10.D	1995 Incentive Compensation Plan, Amended and Restated effective as of December 3, 1998 (Exhibit 10.D to our 1998 Form 10-K).
+10.E	1995 Compensation Plan for Non-Employee Directors, Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective March 9, 1999 to the 1995 Compensation Plan for Non-Employee Directors (Exhibit 10.E.1 to our 1999 Second Quarter Form 10-Q) and Amendment No. 2 effective as of July 16, 1999 to the 1995 Compensation Plan for Non-Employee Directors (Exhibit 10.E.2 to our 1999 Second Quarter Form 10-Q); Amendment No. 3 effective as of February 7, 2001 to the 1995 Compensation Plan for Non-Employee Directors (Exhibit 10.E.1 to our 2001 First Quarter Form 10-Q); Amendment No. 4 effective as of December 7, 2001 to the 1995 Compensation Plan for Non-Employee Directors (Exhibit 10.E.1 to our 2001 Form 10-K).
*+10.E.1	Amendment No. 1 effective as of January 29, 2003 to the 1995 Compensation Plan for Non-Employee Directors.
+10.F	Stock Option Plan for Non-Employee Directors, Amended and Restated effective as of January 20, 1999 (Exhibit 10.F to our 1998 Form 10-K) and Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 1999 Second Quarter Form 10-Q); Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q).
+10.G	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K).
+10.H	1995 Omnibus Compensation Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan; Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.G.1 to our 1998 Form 10-K).
+10.I	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our First Quarter Form 10-Q).

Exhibit Number	Description
+10.J	2001 Omnibus Incentive Compensation Plan, effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K) Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q).
*+10.J.1	Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan.
+10.K	Supplemental Benefits Plan, Amended and Restated effective December 7, 2001. (Exhibit 10.K to our 2001 Form 10-K).
*+10.K.1	Amendment No. 1 effective November 7, 2002 to the Supplemental Benefits Plan.
+10.L	Senior Executive Survivor Benefit Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q).
*+10.L.1	Amendment No. 2 to the Senior Executive Survivor Benefit Plan.
+10.M	Deferred Compensation Plan Amended and Restated as of June 13, 2002 (Exhibit 10.M to our 2002 Second Quarter Form 10-Q).
*+10.M.1	Amendment No. 1 effective November 7, 2002 to the Deferred Compensation Plan.
+10.N	Key Executive Severance Protection Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.O to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of February 7, 2001, to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q).
*+10.N.1	Amendment No. 2 effective November 7, 2002 to the Key Executive Severance Protection Plan and Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan.
+10.O	Director Charitable Award Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of February 7, 2001, to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q).
+10.P	Strategic Stock Plan, Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001, to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q).
*+10.P.1	Amendment No. 2 effective November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective January 29, 2003 to the Strategic Stock Plan.
+10.Q	Domestic Relocation Policy, effective November 1, 1996 (Exhibit 10.Q to EPNG's 1997 Form 10-K).
+10.R	Employee Stock Purchase Plan, Amended and Restated as of January 29, 2002 (Exhibit 10.1 to our Form S-8 filed July 23, 2002).
*+10.R.1	Amendment No. 1 to the Employee Stock Purchase Plan effective as of December 6, 2002.
+10.S	Executive Award Plan of Sonat Inc., Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.R to our 1999 Third Quarter Form 10-Q); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q).

Exhibit Number	Description
+10.T	Omnibus Plan for Management Employees, Amended and Restated effective as of December 3, 1999 and Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed February 11, 2002).
*+10.T.1	Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees.
+10.U	Employment Agreement, Amended and Restated effective as of February 1, 2001, between El Paso and William A. Wise. (Exhibit 10.O to our 2000 Form 10-K).
+10.U.1	Promissory Note dated May 30, 1997, made by William A. Wise to El Paso (Exhibit 10.R to EPNG's First Quarter Form 10-Q); Amendment to Promissory Note dated November 20, 1997 (Exhibit 10.R to EPNG's 1998 First Quarter Form 10-Q).
+10.V	Pledge and Security Agreement, and Promissory Note, each dated August 16, 2001, by and between El Paso and William A. Wise (Exhibit 10.CC to our 2001 Third Quarter Form 10-Q).
+10.W	Letter Agreement dated September 22, 2000, between El Paso and D. Dwight Scott (Exhibit 10.W to our 2002 Third Quarter Form 10-Q).
+10.X	Form of Agreement to Restate Balance of certain compensation under the Estate Enhancement Program dated December 31, 2001, by and between El Paso and the named executives on the exhibit thereto, and Form of Promissory Note dated December 31, 2001, in favor of El Paso by trusts established by named executives, loan amounts, and interest rates (Exhibit 10.AA to our 2001 Form 10-K).
10.Y	Amended and Restated Participation Agreement, dated as of April 12, 2002, by and among El Paso, Limestone Electron Trust, Limestone Electron, Inc., Credit Suisse First Boston (USA), Inc., El Paso Chaparral Holding Company, El Paso Chaparral Holding II Company, El Paso Chaparral Investor, L.L.C., El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., Mesquite Investors, L.L.C., El Paso Electron Overfund Trust, El Paso Electron Share Trust, Electron Trust, Wilmington Trust Company and The Bank Of New York (Exhibit 10.BB to our 2002 Third Quarter Form 10-Q).
10.Y.1	Fifth Amended and Restated Limited Liability Company Agreement of Chaparral Investors, L.L.C., dated as of April 12, 2002 (Exhibit 10.BB.1 to our 2002 Third Quarter Form 10-Q).
10.Y.2	Third Amended and Restated Limited Liability Company Agreement of Mesquite Investors, L.L.C., dated as of March 27, 2000 (Exhibit 10.BB.2 to our 2002 Third Quarter Form 10-Q).
10.Y.3	Amended and Restated Management Agreement dated as of March 27, 2000, among El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., Mesquite Investors, L.L.C., and El Paso Chaparral Investors, L.L.C. (Exhibit 10.BB.3 to our 2002 Third Quarter Form 10-Q).
10.Y.4	Third Amended and Restated Trust Agreement of Limestone Electron Trust, dated as of April 12, 2002, by Wilmington Trust Company, El Paso, as holder of the El Paso Interest, Electron Trust (Exhibit 10.BB.4 to our 2002 Third Quarter Form 10-Q).
10.Y.5	Indenture, dated as of April 26, 2002, among Limestone Electron Trust, Limestone Electron, Inc., The Bank of New York, and El Paso as guarantor (Exhibit 10.BB.5 to our 2002 Third Quarter Form 10-Q).

Exhibit Number	Description
10.Z	Amended and Restated Participation Agreement, dated as of April 24, 2002, by and among El Paso, EPED Holding Company, EPED B Company, Jewel Investor, L.L.C., Gemstone Investor Limited, Gemstone Investor, Inc., Topaz Power Ventures, L.L.C., Emerald Finance, L.L.C., Citrine FC Company, Garnet Power Holdings, L.L.C., Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., Amethyst Power Holdings, L.L.C., Aquamarine Power Holdings, L.L.C., Peridot Finance S.à r.l., Gemstone Administração Ltda., El Paso Gemstone Share Trust, Wilmington Trust Company, and The Bank of New York (Exhibit 10.CC to our 2002 Third Quarter Form 10-Q).
10.Z.1	Shareholder Agreement dated as of April 24, 2002, by and among Gemstone Investor Limited, Jewel Investor, L.L.C. and El Paso, and The Bank of New York (Exhibit 10.CC.1 to our 2002 Third Quarter Form 10-Q).
10.Z.2	Second Amended and Restated Limited Liability Company Agreement of Diamond Power Ventures, L.L.C. dated as of April 24, 2002 (Exhibit 10.CC.2 to our 2002 Third Quarter Form 10-Q).
10.Z.3	Second Amended and Restated Limited Liability Company Agreement of Topaz Power Ventures, L.L.C. dated as of April 24, 2002 (Exhibit 10.CC.3 to our 2002 Third Quarter Form 10-Q).
10.Z.4	Second Amended and Restated Limited Liability Company Agreement of Garnet Power Holdings, L.L.C., dated as of April 24, 2002 (Exhibit 10.CC.4 to our 2002 Third Quarter Form 10-Q).
10.Z.5	Indenture dated as of May 9, 2002, among Gemstone Investor Limited, Gemstone Investor, Inc., The Bank of New York, and El Paso as guarantor (Exhibit 10.CC.5 to our 2002 Third Quarter Form 10-Q).
10.Z.6	Management Agreement, dated as of November 1, 2001, by and among Gemstone Administração Ltda., Garnet Power Holdings, L.L.C. Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., and EPED B Company (Exhibit 10.CC.6 to our 2002 Third Quarter Form 10-Q).
10.AA	Fourth Amended and Restated Partnership Agreement of Clydesdale Associates, L.P. dated as of July 19, 2002 (Exhibit 10.DD to our 2002 Third Quarter Form 10-Q).
10.AA.1	Amended and Restated Sponsor Subsidiary Credit Agreement dated as of July 19, 2002, among Noric Holdings, L.L.C., as Borrower, each Sponsor Subsidiary, Clydesdale Associates, L.P., as Lender, and Wilmington Trust Company, as Collateral Agent for Clydesdale (Exhibit 10.DD.1 to our 2002 Third Quarter Form 10-Q).
10.AA.2	Amended and Restated Guaranty Agreement, dated as of July 19, 2002, made by El Paso, as guarantor, in favor of, severally, each Sponsor Subsidiary, Noric, Noric LP and each Controlled Business (Exhibit 10.DD.2 to our 2002 Third Quarter Form 10-Q).
10.BB	Third Amended and Restated Company Agreement of Trinity River Associates, L.L.C. dated as of March 29, 2002, by and between Sabine River Investors, L.L.C., and Red River Investors, L.L.C. (Exhibit 10.EE to our 2002 Third Quarter Form 10-Q).
10.BB.1	Second Amended and Restated Sponsor Subsidiary Credit Agreement dated as of March 29, 2002, Sabine River Investors, L.L.C., as Borrower, each Sponsor Subsidiary, Trinity River Associates, L.L.C., as Lender, and Wilmington Trust Company, as Collateral Agent for Trinity (Exhibit 10.EE.1 to our Third Quarter Form 10-Q).
10.BB.2	Second Amended and Restated Guaranty Agreement dated as of March 29, 2002, made by El Paso, as guarantor (Exhibit 10.EE.2 to our Third Quarter Form 10-Q).

Exhibit Number	Description
10.CC	Second Amended and Restated Agreement of Limited Partnership of El Paso Energy Partners, L.P. effective as of August 31, 2000 (Exhibit 10.FF to our 2002 Third Quarter Form 10-Q).
*10.CC.1	First Amendment to the Second Amended and Restated Agreement of Limited Partnership of El Paso Energy Partners, L.P.
*10.DD	Senior Secured Interim Term Credit and Security Agreement dated as of March 13, 2003 among El Paso and Citicorp North American, Inc. and Credit Suisse First Boston, acting through its Cayman Island Branch as Initial Lenders and Co-Agents and Salomon Smith Barney Inc. and Credit Suisse First Boston, acting through its Cayman Island Branch as Co-Lead Arrangers and Joint Book Runners and Citicorp North America, Inc. as Agent and as Collateral Agent and Amendment No. 1 to the Senior Secured Interim Term Credit and Security Agreement dated as of March 14, 2003.
*10.EE	Credit Agreement among El Paso Production Company, El Paso Production GOM Inc., Vermejo Minerals Corporation, El Paso Energy Raton, L.L.C. as Subsidiary Borrowers and Guarantors, El Paso Production Holding Company, Sabine River Investors VI, L.L.C. and Sabine River Investors IX, L.L.C. as Guarantors, El Paso Corporation as Lender, and Citicorp North America, Inc. as Loan Administrator dated as of March 13, 2003.
*+10.FF	Form of Indemnification Agreement for each member of the Board of Directors, effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later.
*21	Subsidiaries of El Paso.
*23.A	Consent of Independent Accountants, PricewaterhouseCoopers LLP.
*23.B	Consent of Independent Auditors, Deloitte & Touche LLP.
*23.C	Consent of Huddleston & Co., Inc.
*99.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by sec. 906 has been provided to El Paso Corporation and will be retained by El Paso Corporation and furnished to the Securities and Exchange Commission or its staff upon request.
*99.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by sec. 906 has been provided to El Paso Corporation and will be retained by El Paso Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

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 31st day of March 2003.

EL PASO CORPORATION
Registrant

By /s/ RONALD L. KUEHN, JR.

Ronald L. Kuehn, Jr.
Chairman of the Board
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/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 31, 2003
/s/ H. BRENT AUSTIN (H. Brent Austin)	President and Chief Operating Officer	March 31, 2003
/s/ D. DWIGHT SCOTT (D. Dwight Scott)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 31, 2003
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	March 31, 2003
/s/ BYRON ALLUMBAUGH (Byron Allumbaugh)	Director	March 31, 2003
/s/ JOHN M. BISSELL (John M. Bissell)	Director	March 31, 2003
/s/ JUAN CARLOS BRANIFF (Juan Carlos Braniff)	Director	March 31, 2003
/s/ JAMES F. GIBBONS (James F. Gibbons)	Director	March 31, 2003
/s/ ROBERT W. GOLDMAN (Robert W. Goldman)	Director	March 31, 2003
/s/ ANTHONY W. HALL JR. (Anthony W. Hall Jr.)	Director	March 31, 2003

Signature	Title	Date
/s/ J. CARLETON MACNEIL JR. (J. Carleton MacNeil Jr.)	Director	March 31, 2003
/s/ THOMAS R. MCDADE (Thomas R. McDade)	Director	March 31, 2003
/s/ MALCOLM WALLOP (Malcolm Wallop)	Director	March 31, 2003
(John L. Whitmire)	Director	March 31, 2003
(William A. Wise)	Director	March 31, 2003
/s/ JOE B. WYATT (Joe B. Wyatt)	Director	March 31, 2003

CERTIFICATION

I, Ronald L. Kuehn, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of El Paso Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ RONALD L. KUEHN, JR.

Ronald L. Kuehn, Jr.
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso Corporation

Date: March 31, 2003

CERTIFICATION

I, D. Dwight Scott, certify that:

1. I have reviewed this annual report on Form 10-K of El Paso Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ D. DWIGHT SCOTT

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)
El Paso Corporation

Date: March 31, 2003