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, 2003

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 1-7176

El Paso CGP Company
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**74-1734212** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: (713) 420-2600

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

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: None

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 $1 per share. Shares outstanding on October 11, 2004: 1,000

Documents Incorporated by Reference: None

EL PASO CGP COMPANY

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

/d	= per day	Mgal	= thousand gallons
Bbl	= barrels	MMBbls	= million barrels
BBtu	= billion British thermal units	MMBtu	= million British thermal units
BBtue	= billion British thermal unit equivalents	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	MMwh	= thousand megawatt hours
Km	= kilometers	MTons	= thousand tons
MBbls	= thousand barrels	MW	= megawatt
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units
Mcfe	= thousand cubic feet of natural gas equivalents	Tcfe	= trillion cubic feet of natural 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. Oil includes natural gas liquids unless otherwise specified. 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", "CGP" or "Coastal", we are describing El Paso CGP Company and/or our subsidiaries.

Restatement of Historical Financial Information

In February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. The results of this process indicated that a significant downward revision to our proved reserve estimates was needed. After an investigation into the factors that caused this revision, we determined that a material portion of the downward reserve revisions should be reflected in historical periods. Accordingly, we restated our historical financial information for the years from 1999 to 2002 and for the first nine months of 2003. The investigation determined that certain personnel used aggressive, and at times, unsupportable methods to book proved reserves. In some instances, certain personnel provided historical proved reserve estimates that they knew or should have known were incorrect at the time they were reported. The investigation also found that we did not, in some cases, maintain adequate documentation and records to support historically booked proved natural gas and oil reserves.

As a result of these conclusions, we restated our historical proved natural gas and oil reserve estimates and the financial information derived from these estimates for the periods from 1999 to 2002 and for the first nine months of 2003. The total cumulative impact of the restatement was a reduction of our previously reported stockholder's equity as of September 30, 2003 of approximately $1.1 billion. The restatement had no impact on our overall cash flows during these periods. These restated amounts have been reflected only in this Annual Report on Form 10-K, and we did not revise our historically filed reports for the impacts of this restatement. Consequently, you should not rely on historical information contained in those prior filings since this filing replaces and revises those historically reported amounts.

For a further discussion of the impact of the restatement on our selected financial information, see Part II, Item 6, Selected Financial Data; for a more detailed discussion of the factors leading to the restatement, the restatement methods used and the financial impacts of the restatement, see Item 8, Financial Statements and Supplementary Data, Note 1; and for a discussion of control weaknesses that contributed to this issue and changes we have made or are in the process of making to our control procedures, see Item 9A, Controls and Procedures.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation originally founded in 1955. In January 2001, we became a wholly owned subsidiary of El Paso Corporation (El Paso) through our merger with a wholly owned El Paso subsidiary.

Business Segments

For the years ended December 31, 2003, we operated through four business segments — Pipelines, Production, Field Services and Merchant Energy. Through these segments, we provide the following energy related services:

Interstate Natural Gas Transmission and Storage Services	We own or have interests in approximately 17,300 miles of pipeline and approximately 280 Bcf of storage capacity. We provide customers with interstate natural gas transmission and storage services from a diverse group of supply regions to major markets in the Midwest and western United States.
Production	We own or have interests in approximately 3.9 million net developed and undeveloped acres, and had over 1.0 Tcfe of proved natural gas and oil reserves worldwide at the end of 2003. During 2003, our production averaged approximately 530 MMcfe/d. During the first eight months of 2004, production averaged 367 MMcfe/d.

Midstream Services	Our midstream businesses provide gathering and processing services primarily in south Louisiana.
Power Generation and Supply	Our power business owns or manages over 4,000 MW of gross generating capacity in 8 countries. Our plants serve customers under long-term and market-based contracts or sell to the open market in spot market transactions. This business also manages power supply arrangements with electric utility customers to meet their peak electricity requirements. We have sold or expect to sell substantially all of our domestic power business in 2004.

In addition to our operating segments, we also have discontinued operations. These discontinued operations include our petroleum markets business, which owned and operated refineries in the northeastern U.S. and in Aruba, with a capacity to refine over 430,000 Bbls of oil per day. We completed the sale of substantially all of this business in early 2004.

Below is a description of each of our existing business segments. Our current business 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. For additional discussion of our business segments, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and identifiable assets, see Part II, Item 8, Financial Statements and Supplementary Data, Note 21, which is incorporated herein by reference.

Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage and related services and owns or has interests in approximately 17,300 miles of interstate natural gas pipelines in the U.S. Our systems connect several of the nation's principal natural gas supply regions to several large consuming regions in the U.S. and include access between our U.S. based systems and Canada. In addition, we own or have interests in approximately 280 Bcf of storage capacity used to provide a variety of flexible services to our customers. We conduct our activities primarily through three wholly owned and one partially owned interstate transmission systems along with four underground natural gas storage entities. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2003 Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2003 (BBtu/d)	2002	2001
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,600	6,414	202	4,232	4,130	4,531
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	1,685	1,687	1,569
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,880	—	1,213	1,194	1,017

[1] Includes throughput transported on behalf of affiliates.

We also have five pipeline expansion projects underway as of September 2004 that have been approved by the Federal Energy Regulatory Commission (FERC):

Transmission System	Project	Capacity (MMcf/d)	Description[(1)]	Anticipated Completion Date
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
	EastLeg Wisconsin expansion	142	To replace 4.7 miles of an existing 14-inch natural gas pipeline with a 30-inch line in Washington County, add 3.5 miles of 8-inch looping on the Denmark Lateral in Brown County, and modify ANR's existing Mountain Compressor Station in Oconto County, Wisconsin.	November 2005
	NorthLeg Wisconsin expansion	—	To add 6,000 horse power of electric powered compression at ANR's Weyauwega Compressor station in Waupaca County, Wisconsin	November 2005
CPG	Cheyenne Plains Gas Pipeline (CPG)	576	To construct a 36-inch pipeline to transport gas from the Cheyenne hub in Colorado to interconnecting pipelines near Greensburg, Kansas.	December 2004
	Cheyenne Plains expansion	176	To add approximately 10,300 horsepower of compression to the Cheyenne Plains project.	December 2005

(1) 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.

Partially Owned Interstate Transmission System

Transmission System	Supply and Market Region	As of December 31, 2003 Ownership Interest (Percent)	Miles of Pipeline	Design Capacity[(2)] (MMcf/d)	Average Throughput[(2)] (BBtu/d) 2003	2002	2001
Great Lakes Gas Transmission[(1)]	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,366	2,378	2,224

(1) This system is accounted for as an equity investment.
(2) Volumes represent the system's total design capacity and average throughput and are not adjusted for our ownership interest.

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, 2003 Ownership Interest (Percent)	Storage Capacity[(1)] (Bcf)	Location
ANR Storage	100	56	Michigan
Blue Lake Gas Storage[(2)]	75	47	Michigan
Eaton Rapids Gas Storage[(2)]	50	13	Michigan
Young Gas Storage[(2)]	48	6	Colorado

(1) Includes a total of 75 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.
(2) These systems are accounted for as equity investments as of December 31, 2003.

In addition to these interests in interstate natural gas transmission and storage facilities, we have a 50 percent interest in Wyco Development, L.L.C. (Wyco). Wyco owns the Front Range Pipeline, a state-regulated gas pipeline extending from the Cheyenne Hub to Public Service Company of Colorado's (PSCo)

Fort St. Vrain electric generation plant, and also owns compression facilities on WIC's Medicine Bow Lateral. These facilities are leased to PSCo and WIC, respectively, under long-term leases. Our equity investment in Wyco is approximately $24 million.

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 and related services;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy 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. Our revenues from transportation, storage and related services (transportation services revenues) consist of reservation revenues and usage revenues. Reservation revenues are from customers (referred to as firm customers) whose contracts (which are for varying terms) reserve capacity on our pipeline systems or storage facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) who pay charges based on the volume of gas actually transported, stored, injected or withdrawn. In 2003, approximately 90 percent of our transportation services revenues were attributable to charges paid by firm customers. The remaining 10 percent of our transportation services revenue was attributable to usage charges paid by both firm and interruptible customers. Due to our regulated nature, 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.

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

Markets and Competition

We provide natural gas services to a variety of customers including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear and hydroelectric power for power generation and fuel oil for heating.

Other Matters Impacting Our Markets

Electric power generation is the fastest growing demand sector 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 potentially 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 may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their credit worthiness.

Our existing contracts mature at various times and in varying amounts of throughput capacity. 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.

The following table details the markets we serve and the competition on each of our wholly owned pipeline systems as of December 31, 2003:

Transmission System	Customer Information	Contract Information	Competition
ANR	Approximately 228 firm and interruptible customers	Approximately 537 firm contracts Contracted capacity: 97% Weighted average remaining contract term of approximately four years.	In the Midwest, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast, ANR competes with other interstate pipelines serving electric generation and local distribution companies. ANR also competes directly with other interstate pipelines, including Guardian Pipeline, for markets in Wisconsin. We Energies owns an interest in Guardian, which is currently serving a portion of its firm transportation requirements.
	Major Customer: We Energies (1,050 BBtu/d)	Contract terms expire in 2004-2010.	
CIG	Approximately 130 firm and interruptible customers	Approximately 190 firm contracts Contracted capacity: 97% Weighted average remaining contract term of approximately five years.	CIG serves two major markets. Its "on-system" market, consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its "off-system" market consists 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 its 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 its off-system market consists of other interstate pipelines that are directly connected to its supply sources and transport these volumes to markets in the West, Northwest, Southwest and Midwest.
	Major Customer: Public Service Company of Colorado (187 BBtu/d) (970 BBtu/d) (261 BBtu/d)	 Contract terms expire in 2005. Contract term expires in 2007. Contract term expires in 2009-2014.	

Transmission System	Customer Information	Contract Information	Competition
WIC	Approximately 40 firm and interruptible customers	Approximately 50 firm contracts Contracted capacity: 98% Weighted average remaining contract term of approximately six years.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC's Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply and can readily be expanded as supply increases. Currently there are two other interstate pipelines that transport limited volumes out of this basin.
	Major Customers:		
	Williams Power Company (303 BBtu/d)	Contract terms expire in 2008-2013.	
	Colorado Interstate Gas Company (247 BBtu/d)	Contract terms expire in 2004-2007.	
	Cantera Gas Company (243 BBtu/d)	Contract terms expire in 2004-2013.	
	Western Gas Resources (235 BBtu/d)	Contract terms expire in 2007-2013.	

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. as of December 31, 2003, we controlled over 1 million net acres of leasehold through our onshore operations in 10 states, including Texas, Utah, West Virginia, and Wyoming, and through our offshore operations in federal and state waters in the Gulf of Mexico. We also have international exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia. During 2003, daily production averaged approximately 530 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2003, were approximately 1.1 Tcfe.

In February 2004, we completed estimates of our December 31, 2003 proved reserves. The results of this process indicated that a 1.0 Tcfe downward revision to our proved natural gas and oil reserves was needed. Following an investigation into the factors that caused this significant revision, we determined that a material portion of these revisions should be reflected in prior years and, as a result, we restated our historical proved reserve estimates and our historical financial information derived from these proved reserve estimates. See Part II, Item 6, Selected Financial Data and Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of this restatement.

As part of El Paso's Long-Range Plan, El Paso will focus on developing production opportunities from its asset base in the U.S. and Brazil. Based on this strategy, we will divest our non-core assets, including international properties in Canada, Hungary and Indonesia. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

In June 2004, El Paso announced a back-to-basics plan for its Production businesses. This plan emphasizes strict capital discipline designed to improve capital efficiency through the use of standardized risk analysis, a heightened focus on cost control, and a rigorous process for booking proved natural gas and oil reserves. This back-to-basics approach is designed to stabilize production by improving the production mix across our operating areas, thereby generating more predictable income and cash flows in this business.

Our U.S. operations are divided into the following areas: onshore, offshore, and coal seam. The onshore area includes operations in two primary regions: Texas Onshore and Rocky Mountain. The Texas Onshore region includes our operations along the Texas Gulf Coast and the Rocky Mountain region includes our interests in Utah. The offshore area includes our interests in the Gulf of Mexico primarily in state and federal waters along the coast of Texas and Louisiana. In each of our domestic operating areas, we have extensive acreage and/or seismic holdings, which allow us to be competitive.

In Brazil, our operations are concentrated in the Camamu and Santos Basins. We have been successful with our drilling programs in the Santos and Camamu Basins and are seeking a strategic partner with a strong interest in Brazil to contribute near-term development capital in these two basins.

Natural Gas and Oil Reserves

The tables below provide information about our proved reserves at December 31, 2003. Reserve information in these tables is based on the reserve report dated January 1, 2004, prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates for 84 percent and 16 percent of our properties, respectively. The total estimate of proved reserves prepared independently by Ryder Scott Company and Huddleston & Co., Inc. was within five percent of our internally prepared estimates. 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.

The table below summarizes our estimated proved reserves as of December 31, 2003, and our 2003 production, by area.

	Net Proved Reserves[1]				2003 Production
	Natural Gas	Liquids[2]	Total		
	(MMcf)	(MBbls)	(MMcfe)	(Percent)	(MMcfe)
U.S.					
Onshore					
Texas Onshore	464,351	12,196	537,526	49	122,529
Central	813	4	839	—	831
Rocky Mountains	13,016	12,458	87,763	8	6,376
Total Onshore	478,180	24,658	626,128	57	129,736
Offshore	145,798	6,261	183,362	17	46,444
Coal seam	671	1	678	—	842
Total U.S.	624,649	30,920	810,168	74	177,022
International					
Canada[3]	97,431	2,986	115,347	11	16,987
Hungary	4,401	—	4,401	—	401
Brazil	—	20,543	123,258	11	—
Indonesia[3]	30,520	1,742	40,972	4	—
Total International	132,352	25,271	283,978	26	17,388
Total	757,001	56,191	1,094,146	100	194,410

(1) Net proved reserves exclude royalties and interests owned by others (including net profits interest) and reflects contractual arrangements and royalty obligations at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.
(3) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

The table below summarizes our estimated proved producing reserves, proved non-producing reserves, and proved undeveloped reserves by country as of December 31, 2003:

	Net Proved Reserves[1]			
	Natural Gas (MMcf)	Liquids[2] (MBbls)	Total (MMcfe)	Relative Percentage
U.S.				
Producing	393,729	15,712	487,999	60
Non-Producing	108,300	7,424	152,844	19
Undeveloped	122,620	7,784	169,325	21
Total proved	624,649	30,920	810,168	100
Canada[3]				
Producing	78,944	1,645	88,812	77
Non-Producing	7,835	64	8,218	7
Undeveloped	10,652	1,277	18,317	16
Total proved	97,431	2,986	115,347	100
Brazil				
Undeveloped	—	20,543	123,258	100
Total proved	—	20,543	123,258	100
Other Countries[4]				
Producing	4,401	—	4,401	10
Undeveloped	30,520	1,742	40,972	90
Total proved	34,921	1,742	45,373	100

	Net Proved Reserves[1]			
	Natural Gas (MMcf)	Liquids[2] (MBbls)	Total (MMcfe)	Relative Percentage
Worldwide				
Producing	477,074	17,357	581,212	53
Non-Producing	116,135	7,488	161,062	15
Undeveloped	163,792	31,346	351,872	32
Total proved	757,001	56,191	1,094,146	100

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

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

(3) As of September 2004, we have sold our production operations in Canada.

(4) Includes international operations in Hungary and Indonesia. As of September 30, 2004, we have sold substantially all of our operations in Indonesia.

There are considerable uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control, particularly where such reserves are not currently producing or developed. 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 the natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development drilling or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced.

In addition, during 2003 we sold reserves totaling approximately 173 Bcfe to various third parties. The reserves sold were primarily located in New Mexico, the Gulf of Mexico and western Canada. See Part II, Item 8, Financial Statements and Supplementary Data, Note 24, for a further discussion of our reserves.

Acreage and Wells

The following table details our gross and net interest in developed and undeveloped onshore, offshore, coal seam and international lease and mineral acreage at December 31, 2003. Any acreage in which our 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)]
			(Acreage)			
U.S.						
Onshore	730,220	209,410	737,122	499,291	1,467,342	708,701
Offshore	265,908	171,394	189,243	173,777	455,151	345,171
Coal Seam	804	245	—	—	804	245
Total	996,932	381,049	926,365	673,068	1,923,297	1,054,117
International						
Australia	—	—	355,000	177,500	355,000	177,500
Bolivia	—	—	154,840	15,484	154,840	15,484
Brazil[(3)]	—	—	2,137,770	1,468,371	2,137,770	1,468,371
Canada[(4)]	79,068	61,824	799,250	633,940	878,318	695,764
Hungary	77,376	77,376	—	—	77,376	77,376
Indonesia[(4)]	—	—	1,213,170	378,397	1,213,170	378,397
Total	156,444	139,200	4,660,030	2,673,692	4,816,474	2,812,892
Worldwide Total	1,153,376	520,249	5,586,395	3,346,760	6,739,771	3,867,009

(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.
(3) In April 2004, we announced the sale of 174,679 gross and net acres associated with our Brazilian offshore operations.
(4) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

The U.S. net developed acreage is concentrated primarily in the Gulf of Mexico (45 percent), Utah (35 percent), and Texas (18 percent). The domestic net undeveloped acreage is concentrated primarily in Texas (30 percent), Gulf of Mexico (26 percent), West Virginia (19 percent) and Wyoming (15 percent). Approximately 23 percent, 21 percent and 10 percent of our total U.S. net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2004, 2005 and 2006, respectively. During 2003, we sold approximately 658,424 net acres primarily located in New Mexico, the Gulf of Mexico and western Canada.

The following table details our gross and net interest in productive onshore, offshore, coal seam and international natural gas and oil wells and the number of wells being drilled at December 31, 2003:

	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]
U.S.								
Onshore	679	557	270	202	949	759	9	5
Offshore	205	161	35	27	240	188	2	1
Coal Seam	12	3	—	—	12	3	—	—
Total	896	721	305	229	1,201	950	11	6
International								
Canada[3]	88	74	7	5	95	79	1	1
Other	1	1	—	—	1	1	—	—
Total	89	75	7	5	96	80	1	1
Worldwide Total	985	796	312	234	1,297	1,030	12	7

(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.
(3) As of September 2004, we have sold our production operations in Canada.

During 2003, we sold approximately 265 net productive wells located primarily in New Mexico, the Gulf of Mexico and western Canada. At December 31, 2003, we operated 990 of the 1,030 net productive wells.

The following table details our net exploratory and development wells drilled for each of the three years ended December 31. As a result of the restatement of our proved natural gas and oil reserves, some wells drilled that were previously reported as development wells have been reclassified as exploratory wells in 2002 and 2001. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of this restatement.

	Net Exploratory Wells Drilled[1]			Net Development Wells Drilled[1]		
	2003	2002 (Restated)	2001 (Restated)	2003	2002 (Restated)	2001 (Restated)
U.S.						
Productive	19	18	16	53	166	176
Dry	9	8	5	1	1	17
Total	28	26	21	54	167	193
Canada[2]						
Productive	10	18	21	3	5	38
Dry	6	27	35	1	1	3
Total	16	45	56	4	6	41
Brazil						
Productive	3	—	—	—	—	—
Dry	—	—	5	—	—	—
Total	3	—	5	—	—	—
Other Countries[3]						
Productive	—	1	—	—	—	—
Dry	1	1	2	—	—	—
Total	1	2	2	—	—	—
Worldwide						
Productive	32	37	37	56	171	214
Dry	16	36	47	2	2	20
Total	48	73	84	58	173	234

(1) Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.
(2) As of September 2004, we have sold our production operations in Canada.
(3) Includes international operations in Australia, Hungary and Indonesia. As of September 30, 2004, we have sold substantially all of our operations in 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 table details our net production volumes, average sales prices received, average transportation costs, average production costs and average production taxes associated with the sale of natural gas and oil for each of the three years ended December 31. See our Production segment in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations for a further discussion of volumes, prices, and production costs.

	2003	2002	2001
Net Production Volumes			
U.S.			
Natural gas (Bcf)	142	247	373
Oil, condensate and liquids (MMBbls)	6	7	8
Total (Bcfe)	177	289	422
Canada[1]			
Natural gas (Bcf)	15	17	13
Oil, condensate and liquids (MMBbls)	—	1	1
Total (Bcfe)	17	23	17
Worldwide			
Natural gas (Bcf)	157	264	386
Oil, condensate and liquids (MMBbls)	6	8	9
Total (Bcfe)	194	312	439
Natural Gas Average Sales Price (per Mcf)[2]			
U.S.			
Price, excluding hedges	$ 5.43	$ 3.15	$ 4.23
Price, including hedges	$ 4.72	$ 4.22	$ 4.09
Canada[1]			
Price, excluding hedges	$ 4.87	$ 2.85	$ 2.86
Price, including hedges	$ 4.87	$ 2.84	$ 2.85
Worldwide			
Price, excluding hedges	$ 5.38	$ 3.09	$ 4.18
Price, including hedges	$ 4.73	$ 4.14	$ 4.05
Oil, Condensate, and Liquids Average Sales Price (per Bbl)[2]			
U.S.			
Price, excluding hedges	$25.25	$20.08	$23.10
Price, including hedges	$25.25	$20.12	$23.10
Canada[1]			
Price, excluding hedges	$28.38	$21.56	$17.68
Price, including hedges	$28.38	$21.55	$18.52
Worldwide			
Price, excluding hedges	$25.40	$20.28	$22.75
Price, including hedges	$25.40	$20.31	$22.81
Average Transportation Cost			
U.S.			
Natural gas (per Mcf)	$ 0.15	$ 0.15	$ 0.06
Oil, condensate, and liquids (per Bbl)	$ 0.89	$ 0.66	$ 0.68
Canada[1]			
Natural gas (per Mcf)	$ 0.86	$ 0.19	$ 0.17
Oil, condensate, and liquids (per Bbl)	$ 0.72	$ 0.39	$ 0.26
Worldwide			
Natural gas (per Mcf)	$ 0.22	$ 0.16	$ 0.07
Oil, condensate, and liquids (per Bbl)	$ 0.89	$ 0.62	$ 0.65
Average Production Cost (per Mcfe)			
U.S.			
Average lease operating costs	$ 0.47	$ 0.49	$ 0.37
Average production taxes	0.17	0.08	0.16
Total production costs[3]	$ 0.64	$ 0.57	$ 0.53
Canada[1]			
Average production cost[3]	$ 0.48	$ 0.80	$ 0.74
Worldwide			
Average lease operating costs	$ 0.47	$ 0.52	$ 0.38
Average production taxes	0.16	0.07	0.15
Total production costs[3]	$ 0.63	$ 0.59	$ 0.53

(1) As of September 2004, we have sold our production operations in Canada.

(2) Prices are stated before transportation costs.

(3) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

Acquisition, Development and Exploration Expenditures

The following table details information regarding the costs incurred in our acquisition, development and exploration activities for each of the three years ended December 31, 2003. As a result of the restatement of our proved natural gas and oil reserves, some costs that were previously reported as development costs have been reclassified as exploratory drilling costs for the years 2002 and 2001. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of this restatement.

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.			
Acquisition Costs:			
Proved	$ —	$ 23	$ 87
Unproved	9	12	33
Development Costs	270	569	954
Exploration Costs:			
Delay rentals	4	4	9
Seismic acquisition and reprocessing	1	2	10
Drilling	211	191	163
Total	$495	$ 801	$1,256
Canada[1]			
Acquisition Costs:			
Proved	$ 1	$ 6	$ 232
Unproved	10	7	16
Development Costs	57	80	102
Exploration Costs:			
Seismic acquisition and reprocessing	9	21	10
Drilling	35	49	12
Total	$112	$ 163	$ 372
Brazil			
Acquisition Costs:			
Unproved	$ 4	$ 9	$ 24
Exploration Costs:			
Seismic acquisition and reprocessing	11	32	6
Drilling	84	13	53
Total	$ 99	$ 54	$ 83
Other Countries[2]			
Acquisition Costs:			
Unproved	$ —	$ 1	$ 2
Development Costs	2	2	—
Exploration Costs:			
Seismic acquisition and reprocessing	2	2	—
Drilling	9	8	22
Total	$ 13	$ 13	$ 24
Worldwide			
Acquisition Costs:			
Proved	$ 1	$ 29	$ 319
Unproved	23	29	75
Development Costs	329	651	1,056
Exploration Costs:			
Delay rentals	4	4	9
Seismic acquisition and reprocessing	23	57	26
Drilling	339	261	250
Total	$719	$1,031	$1,735

(1) As of September 2004, we have sold our production operations in Canada.

(2) Includes international operations in Australia, Brazil, Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.

The following table details approximate amounts spent to develop proved undeveloped reserves that were included in our reserve report for each of the three years:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.	$50	$88	$23
Canada	—	3	3
Total	$50	$91	$26

Regulatory and Operating Environment

Our natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world where we do 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. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our 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. Our 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 our 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 our production business for sudden and accidental spills and oil pollution liability.

Our production 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. In addition, offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, El Paso maintains insurance coverage on our behalf with respect to potential losses resulting from these operating hazards.

Markets and Competition

We primarily sell our natural gas and oil to third parties through El Paso Merchant Energy L.P. (El Paso Merchant Energy), a wholly owned subsidiary of El Paso, at spot market prices, subject to customary adjustments. We sell our natural gas liquids at market prices under monthly or long-term contracts, subject to customary adjustments. We also engage in hedging activities with El Paso Merchant Energy on a portion of our natural gas and oil production to stabilize our cash flows and reduce the risk of downward commodity price movements on sales of our production.

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. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms. 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 conducts our midstream activities which includes gathering and processing of natural gas. For the majority of 2003, our assets principally consisted of our consolidated processing assets in south Louisiana.

Processing and Gathering Operations

Our processing and gathering operations provide processing and gathering services to natural gas producers, primarily in the south Louisiana production area. The following tables provide information regarding the operational capacity and volumes of these processing and gathering facilities:

Processing Plants	Inlet Capacity December 31, 2003	Average Inlet Volume 2003	2002	2001	Average Natural Gas Liquids Sales 2003	2002	2001
	(MMcfe/d)	(BBtue/d)			(Mgal/d)		
South Louisiana	2,550	1,627	1,407	1,712	1,726	1,604	1,619
Other areas	49	60	347	254	139	739	976
Total	2,599	1,687	1,754	1,966	1,865	2,343	2,595

Gathering	December 31, 2003 Miles of Pipeline	Throughput Capacity	Average Throughput 2003	2002	2001
		(MMcfe/d)	(BBtue/d)		
Other areas	852	211	101	628	843

Regulatory Environment

We are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979 and various environmental statutes and regulations. Each of our pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and we believe that these systems are in material compliance with the applicable requirements.

Markets and Competition

We compete with major interstate and intrastate pipeline companies in transporting natural gas and NGL's. We also compete 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's. Competition for throughput and natural gas supplies is based on a number or 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 includes the ownership and operation of domestic and international power generation facilities as well as the management of restructured power contracts. As of December 31, 2003, we owned or had interests in 19 power plants in 8 countries with a total generating capacity of 4,281 gross MW. Our commercial focus has historically been either to develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing above-market power purchase agreements. El Paso's Board of Directors authorized a plan in December 2003 that included the sale of four of our six domestic power generation plants. As of September 2004, we have sold two plants with a total generating capacity of 582 gross MW. See Part II, Item 8, Financial Statements and Supplementary Data, Note 4. El Paso continues to seek opportunities to sell or otherwise divest of our remaining domestic power plants and our international assets.

As of December 31, 2003, we owned or had direct investment interests in the following power plants:

Project	Country	El Paso CGP Ownership Interest	Gross Capacity	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
		(Percent)	(MW)			
Domestic						
Midland[(1)]	U.S.	44	1,575	Consumers Power & Dow	2025	Natural Gas
CDECCA[(3)]	U.S.	100	62	—[(2)]	—[(2)]	Natural Gas
Fulton[(3)(4)]	U.S.	100	48	—[(2)]	—[(2)]	Natural Gas
Rensselaer[(3)]	U.S.	100	86	—[(2)]	—[(2)]	Natural Gas
Bastrop[(1)(3)(4)]	U.S.	50	534	—[(2)]	—[(2)]	Natural Gas
Eagle Point[(5)]	U.S.	100	233	—[(2)]	—[(2)]	Natural Gas
Central America						
CEPP[(1)]	Dominican Republic	48	67	CDEEE	2014	Oil
Fortuna[(1)]	Panama	25	300	Union Fenosa	2004, 2005	Hydroelectric
GEOSA[(1)]	Nicaragua	26	115	Union Fenosa	2005, 2008	Oil
Itabo[(1)]	Dominican Republic	25	416	CDEEE	2016	Oil/Coal
Nejapa	El Salvador	87	144	AES & PPL	2004, 2005	Oil
Pedregal[(1)]	Panama	21	50	Union Fenosa	2005	Oil
Tipitapa[(1)]	Nicaragua	60	51	Union Fenosa	2014	Oil
Asia						
Habibullah[(1)]	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna[(1)]	Bangladesh	74	113	Bangladesh Power	2013	Oil
Nanjing[(1)]	China	80	75	Jiangsu Power	2017	Diesel
Saba[(1)]	Pakistan	94	128	Pakistan Water and Power	2029	Oil
Suzhou[(1)]	China	60	109	Jiangsu Power	2016	Diesel
Wuxi[(1)]	China	60	39	Jiangsu Power	2010	Diesel

(1) These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.
(2) These power facilities (referred to as merchant plants) do not have long-term power purchase agreements and, as a result, sell the power they generate into the wholesale power market.
(3) In December 2003, El Paso's Board approved a plan for selling these power facilities.
(4) We completed the sale of these assets in 2004.
(5) This power facility is currently being leased to a third party who has an option to purchase in 2005.

In addition to our power plants above, we were involved in activities in 2001 and 2002 that we have referred to as our power restructuring business. These activities involved restructuring above-market, long-term power purchase agreements with utilities that were originally tied to older power plants built under the Public Utility Regulatory Policies Act of 1978 (PURPA). These PURPA facilities were typically less efficient and more costly than newer power generation facilities. Our power restructuring activities included restructuring the contracts held by our consolidated Eagle Point and CDECCA power facilities. In the restructuring, the contracts were amended so that the power sold to the utilities did not have to be provided from the specific power plant, but could be obtained in the wholesale power market. While we are no longer actively seeking to restructure additional power purchase contracts, we continue to manage the physical purchase and sale of electricity as required under the restructured power contracts. As of December 31, 2003, our only significant remaining restructured power contract is held by our wholly owned subsidiary, Utility Contract Funding, L.L.C. (UCF). Morgan Stanley supplies the fuel under this contract and PSEG is obligated to purchase a minimum annual volume of 1,666 MMwh under this contract through 2016. We sold our interest in UCF in June 2004.

Regulatory Environment

Our domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to the rates, terms and conditions of service of these regulated plants. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Our cogeneration power production activities are regulated by the FERC under PURPA with respect to rates, procurement and provision of services and operating standards. Our power generation activities are also subject to federal, state and local environmental regulations.

Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of the countries in which we 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, are sometimes limited and are at risk to change, which may affect our contractual arrangements. Many detailed rules and procedures are yet to be issued, and we expect that the interpretation and modification of existing rules in these jurisdictions will evolve over time.

Markets and Competition

The domestic power generation industry continues to evolve and regulatory initiatives have been adopted at the federal and state level aimed at increasing competition in the power generation business. As a result, our domestic facilities are required to compete in the marketplace in which operating efficiency and other economic factors will determine success. We are likely to face intense competition from generation companies as well as from the wholesale power markets.

Many of our international power generation facilities sell power under long-term power purchase agreements primarily with power transmission and distribution companies owned by the local governments where the facilities are located. When these long-term contracts expire, these facilities will be subject to regional market and competitive risks.

Discontinued Operations

Our discontinued operations consist of our petroleum markets and coal mining businesses.

Petroleum Markets. In 2003, El Paso announced its intent to sell our petroleum markets business since it was not core to El Paso's primary natural gas business. During 2003 and 2004, El Paso sold substantially all of our petroleum markets assets. As of December 31, 2003, our petroleum markets business owned or had interests in two crude oil refineries and two chemical production facilities and had petroleum terminalling and related marketing operations. Our refineries operated at 74 percent of their combined daily capacity in 2003, at 66 percent in 2002 and at 71 percent in 2001. The aggregate sales volumes at our wholly owned refineries were approximately 118 MMBbls in 2003, 110 MMBbls in 2002 and 131 MMBbls in 2001. Of our total refinery sales in 2003, 24 percent was gasoline, 38 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 38 percent was heavy industrial fuels and other products. The following table presents information on our wholly-owned refineries as of and for the years ended December 31:

		Average Daily Throughput			As of December 31, 2003	
Refinery	**Location**	**2003**	**2002**	**2001**	**Daily Capacity**	**Storage Capacity**
		(In MBbls)				
Aruba[1]	Aruba	173	146	178	280	14,652
Eagle Point[2]	Westville, New Jersey	140	127	118	150	8,492
Mobile[3]	Mobile, Alabama	6	9	10	—	—
Total		319	282	306	430	23,144

(1) In March 2004, we completed the sale of our Aruba refinery to Valero Energy Corporation.

(2) In January 2004, we completed the sale of our Eagle Point refinery to Sunoco Corporation.

(3) In July 2003, we sold our Mobile refinery to Trigeant EP, Ltd. These volumes only reflect those produced prior to the sale of the refinery.

Our chemical plants produce gasoline additives and paraxylene at our facilities in Wyoming and Montreal. The following table provides information on sales volumes from our wholly owned chemical facilities in the U.S. for each of the three years ended December 31:

	2003	2002	2001
		(MTons)	
Industrial[1]	417	512	492
Agricultural[1]	352	380	378
Gasoline additives[2]	139	199	173
Total	908	1,091	1,043

(1) In December 2003, we sold our chemical facilities that produced nitrogen-based industrial and agricultural products to Dyno Nobel, Inc. We expect to sell our remaining chemical facilities in 2004.

(2) Removed from service in October 2003.

Our petroleum markets business is subject to federal, state and local environmental regulations and its customers are principally independent energy marketers and retailers.

Coal Mining. Prior to its discontinuance in 2002, our coal mining business controlled reserves totaling 524 million recoverable tons and produced high-quality bituminous coal from reserves in Kentucky, Virginia and West Virginia. The extracted coal was primarily sold under long-term contracts to power generation facilities in the eastern U.S. During late 2002 and early 2003, these operations were sold.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 18, and is incorporated herein by reference.

Employees

As of September 24, 2004, we had approximately 856 full-time employees, none of whom are subject to collective bargaining agreements.

Executive Officers of the Registrant

Our executive officers as of October 11, 2004, 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
Douglas L. Foshee	Chairman of the Board, President and Chief Executive Officer	2003	45
D. Dwight Scott	Executive Vice President and Chief Financial Officer and Director	2002	41
Robert W. Baker	Executive Vice President, General Counsel and Director	1996	48

Douglas L. Foshee has served as our Chairman of the Board, President and CEO since January 2004. Mr. Foshee has been President, Chief Executive Officer, and a Director of El Paso since September 2003. Mr. Foshee became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. In December 2003, several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, filed for bankruptcy protection whereby the subsidiaries will jointly resolve their asbestos claims. Prior to that, Mr. Foshee was President, Chief Executive Officer, and Chairman of the Board at Nuevo Energy Company. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Operating Officer and Chief Executive Officer. He held various positions in finance and new business ventures with ARCO International Oil and Gas Company and spent seven years in commercial banking, primarily as an energy lender.

D. Dwight Scott has served as our Executive Vice President, Chief Financial Officer and as a Director since January 2004. 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. Mr. Scott was Executive Vice President of Power for El Paso Merchant Energy from December 2001 to June 2002, and he served as Chief Financial Officer of El Paso Global Networks from October 2000 to November 2001. From January 1999 to October 2000, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

Robert W. Baker has served as our Executive Vice President and General Counsel since January 2004 and as a Director since April 2004. Mr. Baker has been Executive Vice President and General Counsel of El Paso since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. 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.

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 are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 18, and is incorporated herein by reference.

Following is a description of certain environmental proceedings to which a governmental authority is a party and potential monetary sanctions are $100,000 or more.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality (TCEQ) issued an "Executive Director's Preliminary Report and Petition" seeking $645,477 in penalties relating to air violations alleged to have occurred at our former Corpus Christi, Texas refinery from 1996 to 2000. We have filed a hearing request to protect our procedural rights and have initiated negotiations with the TCEQ.

Coastal Eagle Point. The 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). The Orders alleged noncompliance with the New Jersey Air Pollution Control Act, primarily pertaining to excess emissions reported since 1998 by the Eagle Point refinery in Westville, New Jersey. On February 24, 2003, the Environmental Protection Agency (EPA) Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair (LDAR) program. Alleged violations include a failure to monitor all components and failure to timely repair leaking components. The Eagle Point refinery resolved the claims of the U.S. and the State of New Jersey in a Consent Decree on September 30, 2003, pursuant to the EPA's refinery enforcement initiative. The Consent Decree was entered on December 2, 2003. We paid a civil penalty of $1.25 million to the U.S. and $1.25 million to New Jersey. We contributed $1.0 million to an environmentally beneficial project near the refinery. The Eagle Point refinery will invest an estimated $3 to $7 million to upgrade the plant's environmental controls by 2008. The Eagle Point Refinery was sold in January 2004. We will share certain future costs associated with implementation of the Consent Decree pursuant to the Purchase and Sale Agreement. On April 1, 2004, the DEP issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking $183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003 at the refinery, prior to the sale. We are reviewing the information behind the excess emission events and have filed an administrative appeal contesting the penalty.

St. Helens. On November 11, 2003, our St. Helens, Oregon chemical plant discovered a release of ammonia at the facility and reported the release to the National Response Center and state and local contacts on November 12, 2003. The EPA has alleged violations of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and the Emergency Planning and Community Right-to-Know Act (EPCRA) reporting requirements associated with the reporting of the release. On December 3, 2003, the St. Helens plant was sold to Dyno Nobel, Inc. On April 21, 2004, the EPA issued a demand to El Paso Merchant Energy — Petroleum Company for penalties for the alleged violations. We responded to the EPA demand, and we have resolved the alleged violations by agreeing to a penalty of $50,345 and by agreeing to conduct a supplemental project costing $59,581.

Natural Buttes. On May 19, 2003, we met with the EPA to discuss potential "prevention of significant deterioration" violations due to a de-bottlenecking modification at Colorado Interstate Gas Company's facility. The EPA issued an Administrative Compliance Order and we are in negotiations with the EPA as to the appropriate penalty.

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

None.

PART II

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

All of our common stock, par value $1 per share, is owned by El Paso and, accordingly, our common stock is not publicly traded.

ITEM 6. SELECTED FINANCIAL DATA

The information for the years from 1999 until 2002 and for the first nine months of 2003 has been restated. For a further discussion of the restatement and the 2003, 2002 and 2001 restatement amounts, see Item 8, Financial Statements and Supplementary Data, Note 1. See the notes to the table below for the impact of this restatement on 2000 and 1999. The following historical selected financial data excludes our petroleum markets and coal mining businesses, which are presented as discontinued operations in our financial statements for all periods. The selected financial data below should be read together with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8, Financial Statements and Supplementary Data included in this Annual Report on Form 10-K. These selected historical results are not necessarily indicative of results to be expected in the future.

	Year Ended December 31, (In millions)				
	2003	2002 Restated[1]	2001 Restated[1]	2000 Restated[1][2]	1999 Restated[1][2]
Operating Results Data:					
Operating revenues	$2,374	$3,826	$3,964	$3,533	$2,334
Merger-related costs[3]	—	—	787	13	—
Depreciation, depletion and amortization	517	630	836	601	390
Ceiling test charges	109	521	537	—	152
Loss (gain) on long-lived assets	97	(7)	69	(1)	—
Operating income (loss)	520	777	(346)	895	484
Income taxes (benefit)	(57)	109	(87)	220	99
Income (loss) from continuing operations	175	316	(493)	520	388

	As of December 31, (In millions)				
	2003	2002 Restated[1]	2001 Restated[1]	2000 Restated[1][2]	1999 Restated[1][2]
Financial Position Data:					
Total assets	$12,409	$15,555	$16,768	$17,185	$13,334
Long-term debt	5,011	4,985	5,056	5,600	3,305
Stockholder's equity	3,345	3,352	3,498	3,477	2,875

(1) In February 2004, we completed an assessment of our December 31, 2003 proved natural gas and oil reserve estimates. The assessment indicated a downward revision to our proved reserve estimates of 1.0 Tcfe was needed. Upon completion of an investigation into the factors that caused this revision, we determined that a material portion of the revision should be reflected in all of the historical periods included in this Annual Report on Form 10-K. As a result, we restated our historical financial statements for all periods to reflect the impacts of the revised reserve estimates on the financial statement amounts. The cumulative impact of the restatement on total stockholder's equity as of September 30, 2003 (the most recent balance sheet filed) was a reduction of approximately $1.1 billion, which includes the reduction to beginning stockholder's equity as of January 1, 2001 of approximately $1.1 billion. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of our restatement process as well as the financial impacts of the restatement on 2001, 2002 and 2003. The financial impacts on 1999 and 2000 of the restatement were as follows:

	2000		1999	
	Reported	**Restated**	**Reported**	**Restated**
	(In millions)			
Income from continuing operations	$ 531	$ 520	$ 468	$ 388
Total assets	18,875	17,185	15,123	13,334
Stockholder's equity	4,550	3,477	3,937	2,875

The restated stockholder's equity at December 31, 1999 includes a decrease in 1999 income of $80 million, net of tax, due to an increased ceiling test charge, partially offset by lower depletion expense, as well as a reduction to beginning retained earnings of $1 billion for charges that would have occurred in periods prior to January 1, 1999 as a result of our revised reserve levels. As discussed in Item 8, Financial Statements and Supplementary Data, Note 1, we revised our reserves for the periods from December 31, 2000 to September 30, 2003 using a reserve reconstruction approach. For each quarter from December 31, 1998 through the third quarter of 2000, we estimated reserves using an approach that involved the use of a "reserve over production ratio" based on the reconstructed December 31, 2000 reserve estimates. The reserve over production ratio provided the estimated life of reserves based on production levels. We applied that ratio to the actual historical period production levels to calculate estimated historical reserves for each period. In determining the reserve over production ratio to use for each period, historical prices at the end of each quarter were considered, since at different pricing levels, more or less reserves are economical to produce, which also impacts capital cost, operating cost and revenue assumptions in determining cash flows that will be derived from reserves. These overall quarterly reserve levels were then used to recalculate the associated net future cash flows for each quarter during those periods. Ceiling test charges and depreciation, depletion and amortization rates were then determined based on these restated estimated reserve levels and related net future cash flows. Finally, we assessed the reasonableness of our initial adjustment as of December 31, 1998 based on historical prices and our historical capitalized costs prior to that time. Based on that assessment, we believe the amount recorded as a retained earnings adjustment on January 1, 1999 reasonably reflects the financial statement impact of our restated reserve levels that would have occurred prior to that time. We believe the approach used to reconstruct our historical reserve estimates was reasonable in light of the information available to us and the circumstances surrounding our restatement. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of the methodologies used to restate our natural gas and oil reserves and the reasons for the differences in the methods used in computing our restated reserves.

The "as reported" income from continuing operations differs from those amounts originally included in our 2000 Form 10-K by $123 million for 2000 and $31 million for 1999 due to reclassifications associated with our discontinued operations and other minor reclassifications which had no impact on previously reported net income.

(2) The impacts of the historical restatements for the years ended December 31, 2000 and 1999 have not been audited.

(3) During 2001, we merged with El Paso Corporation and incurred employee, business and integration costs related to this merger.

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 46. The historical financial information in this section has been restated as further discussed in Item 8, Financial Statements and Supplementary Data, Note 1. The information contained in this discussion also presents our petroleum markets and our coal mining businesses as discontinued operations for all periods.

Liquidity and Capital Resources

Liquidity

We rely on cash generated from our internal operations and loans from El Paso through its cash management program as our primary sources of liquidity, as well as asset sales and capital contributions from El Paso. We expect that our future funding for working capital needs, capital expenditures and debt service will continue to be provided from some or all of these sources. Each of these sources is 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. Cash generated by future asset sales may depend on the overall economic conditions of the industries served by these assets, the condition and location of the assets and the number of interested buyers.

El Paso is a significant source of liquidity to us, and we participate in its cash management program. Under this program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically and consistently borrowed cash from El Paso under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to El Paso via the cash management program based on its expected cash needs. On December 31, 2003, El Paso authorized a capital contribution of $1.5 billion to us and as of December 31, 2003, we had a note payable to El Paso of $906 million related to this program. This note is classified as a current liability in our balance sheet because it is due upon demand. Our ability to rely on advances from El Paso can be impacted by its credit standing, its requirement to repay debt and other financing obligations, and the cash demands from other parts of its business. If El Paso were unable to meet its liquidity needs, we would not have access to this source of liquidity. Furthermore, we would be required to repay affiliated company payables, if demanded. However, we do not anticipate that El Paso will require us to repay these payables during 2004.

In February 2004, El Paso completed the December 31, 2003 reserve estimation process for its proved natural gas and oil reserves which included reserves in our Production segment. As a result of this review, El Paso announced that it was significantly reducing its proved natural gas and oil reserve estimates, including our estimates. Following the conclusion of an independent investigation into this matter, El Paso announced that a restatement of its historical financial statements, as well as ours, was required.

El Paso believes that a material restatement of its financial statements would have constituted events of default under its $3 billion revolving credit facility and various other financing transactions, specifically under the provisions related to representations and warranties on the accuracy of its historical financial statements and on El Paso's debt to capitalization ratio. During 2004, El Paso received several waivers on its $3 billion revolving credit facility and various other financing transaction to address the restatement. These waivers continue to be effective. El Paso also received an extension of time with various lenders until November 30, 2004 to file its first and second quarter 2004 Forms 10-Q, which it expects to meet. If El Paso is unable to file its Forms 10-Q by that date and it is not able to negotiate an additional extension of the filing deadline, the $3 billion revolving credit facility and various other financing transactions could be accelerated. As part of obtaining its waivers, El Paso also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default, and limitations on the ability of El Paso and its subsidiaries to repay indebtedness scheduled to mature after June 30, 2005. Although two of our subsidiaries

(ANR and CIG) are eligible to borrow under El Paso's $3 billion revolving credit facility, they do not have any borrowings or letters of credit outstanding under that facility. Based upon a review of the provisions of our indentures and the financing agreements, we believe that a default on El Paso's $3 billion revolving credit facility would not result in an event of default under our other debt agreements unless such default resulted in the acceleration of El Paso's $3 billion revolving credit facility or other transactions collateralized by the same assets, and our subsidiaries failed to perform their obligations under their guarantees of such debt.

Various other financing arrangements entered into by El Paso and its subsidiaries, including us, include covenants that require us to file financial statements within specified time periods. Non-compliance with these covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the default can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The filing of our first and second quarter 2004 Forms 10-Q will cure the events of non-compliance resulting from our failure to file financial statements. We have not received a notice of the default caused by our failure to file our financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

If El Paso were subject to voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. We believe that claims to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, there is no assurance that El Paso and/or its other subsidiaries or their creditors would not advance such a claim in a bankruptcy proceeding. If we were to be substantively consolidated in a bankruptcy proceeding with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and our liquidity.

Some of our subsidiaries are subsidiary guarantors of El Paso's $3 billion revolving credit facility and other financing transactions. In connection with their guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the $3 billion revolving credit facility and approximately $300 million of other financing arrangements including leases, letters of credit and other facilities. Our ownership in the above mentioned companies is subject to change if El Paso's lenders under these facilities exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition. In addition, one of our subsidiaries has pledged as collateral a portion of its natural gas and oil properties to support the obligations of some of our affiliates to make payments in connection with the settlement of various lawsuits arising out of the Western Energy Crisis. If our affiliates fail to make those payments, the properties that our subsidiary has pledged would be subject to foreclosure, which could have a material adverse effect on our financial position, results of operations and cash flows.

We have cross-acceleration provisions in our long-term debt-agreements which, if triggered, could result in the acceleration of our debt. The most restrictive indenture has a cross-acceleration threshold of $5 million. The acceleration of our long-term debt would adversely affect our liquidity position and, in turn, our financial condition.

We believe we will generate sufficient funds through our operations, asset sales, financing activities and advances from El Paso to meet all of our cash needs.

Overview of Cash Flow Activities

For the years ended December 31, 2003 and 2002 our cash flows from continuing operations are summarized as follows:

	2003	2002 (Restated)[1]
	(In millions)	
Cash flows from operating activities	$1,184	$ 526
Cash flows from investing activities	(671)	66
Cash flows from financing activities	(491)	(605)

(1) Cash flows from continuing operating, investing and financing activities were restated. However, the overall cash flows for 2002 were unaffected.

Cash From Continuing Operating Activities

Net cash provided by operating activities were $1.2 billion in 2003 versus $0.5 billion in 2002. In our operating activities, we experienced a $0.8 billion decline in 2003 in cash generated from our operations, before asset and liability changes, primarily as a result of sales of operating assets during both 2002 and 2003 and the effects of lower capital spending in our Production segment. In 2003, changes in operating assets and liabilities were a source of cash of $0.3 billion as compared to a use of cash of $1.1 billion in 2002.

Cash From Continuing Investing Activities

Net cash used in investing activities in 2003 consisted primarily of $994 million in capital expenditures. Offsetting this use of cash was $384 million of proceeds from the sale of assets and investments. Our 2003 capital expenditures includes the following (in millions):

Pipelines	$172
Production[1]	800
Field Services	17
Merchant Energy	5
Total	$994

(1) Includes $72 million of capital expenditures paid in 2003 related to projects started and accrued in prior years, and $5 million spent on equity investments.

Under our current plan, we expect to spend between approximately $306 million and $579 million in each of the next three years in our pipelines segment for capital expenditures through a combination of internally generated funds and external financing. These capital expenditures will be primarily spent on maintenance and expansion projects.

In our Production segment, we currently expect to reduce our total capital expenditures from approximately $723 million in 2003 to approximately $340 million in 2004. In addition, we expect to receive additional funds from a third-party investment program in 2004 that will allow us to expand our overall capital development programs. Under this program, third parties contribute capital for the drilling and development of a specific package of wells in exchange for a net profits interest in each well. Based on disappointing results in a portion of the program, one of the third party investors elected to cease further investment in the program. See Item 8, Financial Statements and Supplementary Data, Note 24, for a discussion of our third-party investment program.

We continually evaluate our capital expenditure program which 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.

We will continue to divest our non-core assets based on the strategic direction outlined in El Paso's Long-Range Plan (see Part I, Item 1, Business for a further discussion of El Paso's Long-Range Plan and Item 8, Financial Statements and Supplementary Data, Notes 3 and 10, for a further discussion of these divestitures and other asset divestitures of our discontinued operations).

Cash From Continuing Financing Activities

Net cash used in financing activities in 2003 consisted primarily of payments on affiliated notes payable of $1.4 billion, payments to retire long-term debt of $0.6 billion and dividend payments to El Paso of $0.5 billion. Offsetting this use of cash were $1.5 billion of capital contributions from our parent and $0.4 billion of cash contributed by our discontinued operations.

Cash Flows of Discontinued Operations

During 2003, our discontinued operations generated $0.6 billion of cash through sales of inventories at our refineries and asset sales, offset by capital expenditures of $0.2 billion. These net cash inflows were distributed to our continuing operations.

Contractual Obligations and Off-Balance Sheet Arrangements

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. The following discusses those contingent obligations, often referred to as off-balance sheet arrangements. We also 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 other accrued liabilities. Other obligations such as operating leases and capital commitments are not reflected in our financial statements.

Off-Balance Sheet Arrangements and Related Liabilities

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, 2003, we had approximately $43 million of both financial and performance guarantees, including $23 million of guarantees related to our petroleum markets discontinued operations, not otherwise reflected in our financial statements. The remaining guarantees relate to our domestic and international power operations.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2003, for each of the years presented (all amounts are undiscounted and are in millions):

	2004	2005	2006	2007	2008	Thereafter	Total
Long-term financing obligations:[1]							
Principal	$310	$363	$ 654	$ 58	$476	$3,468	$ 5,329
Interest	398	373	350	313	300	3,195	4,929
Other contractual liabilities[2]	7	8	5	4	2	19	45
Operating leases[3]	21	20	21	18	17	59	156
Other contractual commitments and purchase obligations:[4]							
Transportation and storage[5]	43	42	40	37	37	132	331
Other[6]	185	6	1	1	0	0	193
Total contractual obligations	$964	$812	$1,071	$431	$832	$6,873	$10,983

(1) See Item 8, Financial Statements and Supplementary Data, Note 16.

(2) Includes contractual, environmental and other obligations included in other noncurrent liabilities in our balance sheet.

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

(4) Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations.

(5) These are commitments for firm access to natural gas transportation and storage capacity.

(6) Includes commitments for drilling and seismic activities in our production operations and various other maintenance, engineering, procurement and construction contracts used by our other operations.

Results of Operations

Overview

In February 2004, we completed the December 31, 2003 reserve estimation process for our proved natural gas and oil reserve estimates. The results of this process indicated that a 1.0 Tcfe downward revision in our proved reserves was needed. After an investigation into the factors that caused this revision, it was determined that a material portion of these reserve revisions should be reflected in the historical periods in this Annual Report on Form 10-K. Accordingly, our historical financial results for 1999 through 2002 and for the first three quarters of 2003 were restated. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of the restatement.

Our management, as well as El Paso's management, uses earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business consists of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. We believe EBIT is helpful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

Below is a reconciliation of our consolidated operating income (loss) to our EBIT and our EBIT to our consolidated net loss for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Operating revenues	$ 2,374	$ 3,826	$ 3,964
Operating expenses	(1,854)	(3,049)	(4,310)
Operating income (loss)	520	777	(346)
Earnings (loss) from unconsolidated affiliates	(12)	113	220
Other	71	—	63
EBIT	579	890	(63)
Interest and debt expense	(403)	(421)	(420)
Affiliated interest expense, net	(41)	(9)	(46)
Distributions on preferred interests of consolidated subsidiaries	(17)	(35)	(51)
Income taxes	57	(109)	87
Income (loss) from continuing operations	175	316	(493)
Discontinued operations, net of income taxes	(1,297)	(365)	(85)
Extraordinary items, net of income taxes	—	—	(11)
Cumulative effect of accounting changes, net of income taxes	(12)	14	—
Net loss	$(1,134)	$ (35)	$ (589)

Segment Results

Our current business segments are Pipelines, Production, Field Services and Merchant Energy. These segments provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. We reclassified our historical coal mining operations in the second quarter of 2002 and our petroleum markets operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Our Merchant Energy segment's results for all periods presented reflect this change. In December 2003, El Paso announced its Long-Range Plan. Under the Long-Range Plan, our business will be divided into two primary business lines: regulated and unregulated. Our regulated businesses will include our existing Pipelines segment, while our unregulated businesses will include our Production, Field Services and Merchant Energy segments. Below is a summary of EBIT by segment, followed by a discussion of the year over year results of each of our business segments, our corporate activities, interest and debt expense, affiliated interest expense, distributions on preferred interests of consolidated subsidiaries, income taxes and the results of our discontinued petroleum markets and coal mining operations.

EBIT by Segment	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Regulated Businesses			
Pipelines	$500	$537	$ 292
Unregulated Businesses			
Production	92	(52)	163
Field Services	(52)	15	72
Merchant Energy	24	409	108
Segment EBIT	564	909	635
Corporate and other	15	(19)	(698)
Consolidated EBIT from continuing operations	$579	$890	$ (63)

As indicated above, the results for 2002 and 2001, as well as for the nine months ended September 30, 2003 have been restated for adjustments to our natural gas reserve estimates. See Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatement and the manner in which our segments were affected.

Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage and related services in the U.S. Our interstate natural gas transportation systems face varying degrees of competition from other pipelines, as well as from alternative 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. This shift has impacted the volatility of our revenues, and 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 in 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, including a reasonable return on our invested capital. As a result, our revenues 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 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 renegotiated 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, at times, we discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

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

Pipelines Segment Results

	2003	2002	2001
	(In millions, except volume amounts)		
Operating revenues[1]	$ 918	$ 934	$1,054
Operating expenses[1]	(521)	(515)	(859)
Operating income	397	419	195
Other income	103	118	97
EBIT	$ 500	$ 537	$ 292
Throughput volumes (BBtu/d)[2]	8,158	8,087	8,109

(1) Within our revenues and operating expenses are amounts related to our Dakota gasification facility. This contract had minimal impact on operating income or EBIT. For the years ended December 31, 2003, 2002 and 2001, revenues on this contract were $32 million, $31 million and $50 million, and operating expenses were $31 million, $27 million and $49 million.

(2) Throughput excludes volumes related to our equity investment in the Alliance Pipeline system which was sold. Throughput volumes exclude intrasegment activities. Prior period volumes have been revised to be consistent with the current year presentation which includes billable transportation throughput volume for storage withdrawal.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

For the year ended December 31, 2003, our EBIT was $37 million lower than in 2002. Lower operating revenues and non-operating income contributed to the reduced EBIT levels.

Our lower 2003 EBIT was impacted by a number of revenue items. In July 2002, CIG sold its Panhandle field and other production properties which reduced 2003 revenues by $50 million and resulted in an EBIT decline of $29 million. Transportation and storage revenues decreased $10 million due to contract changes relating to ANR's significant customer, We Energies. These direct impacts to EBIT were offset by the completion of the Front Range and other system expansions during 2002 and 2003, and new transportation contracts which resulted in higher reservation revenues of $17 million and EBIT of $15 million. We also experienced higher revenues and EBIT of $11 million due to higher volumes and prices on natural gas retained by our regulated systems in excess of amounts we used in our pipeline operations.

Our lower 2003 EBIT was also impacted by lower other non-operating income of $15 million. The decrease was primarily due to lower 2003 equity earnings of $20 million from our investment in Alliance Pipeline, which was sold in the first quarter of 2003, and $11 million from the favorable resolution of uncertainties in 2002 associated with the sale of our interests in the Iroquois and Empire State pipeline systems and Gulfstream pipeline project.

Finally, our 2003 EBIT was favorably impacted by our re-application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* by our CIG and WIC systems, resulting in an $18 million one-time increase in other income. This income resulted from our recording the regulatory assets of these systems. SFAS No. 71 allows a company to capitalize items that will be considered in future rate making actions and this income resulted from the capitalization of those items that we believe will be considered in CIG's and WIC's future rate cases. At the same time CIG and WIC re-applied SFAS No. 71, they adopted the FERC depreciation rate for their regulated plant and equipment. This change will result in depreciation expense increases in the future of approximately $9 million annually. Based on our estimates, we anticipate that the overall annual EBIT impact as a result of our re-application of SFAS No. 71 will be an annual reduction of EBIT of approximately $10 million.

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

Our EBIT for 2002 increased $245 million from 2001. The increase primarily resulted from $192 million of merger-related charges incurred in 2001 following our merger with El Paso and $27 million of lower general, administrative and operating costs in 2002 as a result of cost efficiencies following this merger. Also contributing to the EBIT increase were a favorable impact from system expansions, which were placed in service in late 2001 resulting in increased revenue in 2002 of $30 million, operating expenses of $8 million and EBIT of $22 million, $18 million from lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002, and an $11 million gain on the sale of pipeline expansion rights in February 2002. Partially offsetting these EBIT increases was a reduction of $27 million as a result of CIG's sale of its Panhandle field in July 2002, a $28 million decrease in revenues and EBIT due to lower sales of our natural gas retained on our regulated systems in excess of amounts used in our operations, and $22 million of lower transportation revenues due to milder weather in 2002.

Production Segment

Our Production segment results have been restated for revisions to our natural gas and oil reserve estimates. Our 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 and sell the products at attractive prices. Consistent with El Paso's Long-Range Plan announced in December 2003, El Paso's long-term strategy includes developing production opportunities primarily in the U.S. and Brazil, while prudently divesting of production properties outside of these regions. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia. Our operations in Canada include activities in Nova Scotia where, in the first quarter of 2004, we drilled an exploratory well that was not commercially viable and recorded a $24 million ceiling test charge.

In June 2004, El Paso announced a back-to-basics plan for its production business. This plan emphasizes strict capital discipline designed to improve capital efficiency through the use of standardized risk analysis, a heightened focus on cost control, and revised controls for booking proved natural gas and oil reserves. This back-to-basics approach is expected to stabilize production by improving the production mix across its operating areas, thereby generating more predictable income and cash flows in the production business.

Reserves and Costs

In February 2004, we completed estimates of our proved natural gas and oil reserves as of December 31, 2003. These estimates were prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates of our proved reserves for 84 percent and 16 percent of our properties. The total estimate of proved reserves prepared by these engineers is within five percent of our internally prepared estimates.

The proved reserve estimates as of December 31, 2003, indicated a 1.0 Tcfe downward revision of our proved natural gas and oil reserves was needed. The downward revisions related primarily to our Texas onshore and offshore Gulf of Mexico regions. Due to the significance of the reserve revision, the Audit Committee of El Paso's Board of Directors engaged a law firm to conduct an independent investigation into the reasons for the revisions. The investigation concluded that a material portion of these revisions related to prior periods, and as a result we restated our historical reserve estimates and our historical financial information derived from these estimates. The reserve restatement involved utilizing the reserve estimate prepared as of December 31, 2003 and then reconstructing historical reserve data using actual historical production data and re-engineered sales of proved reserves. Following this reserve reconstruction and the recalculation of the discounted future net cash flows, ceiling test calculations, depletion rates, and gains and losses on asset sales were recomputed for each period restated. See Item 8, Financial Statements and Supplementary Data, Notes 1, 7 and 24 for a discussion of our ceiling test calculation and the restatement of our natural gas and oil reserves. The restatement will result in a lower depletion rate and reduced exposure to ceiling test charges in the future than would have been the case absent the restatement.

Since December 31, 2001, we have sold approximately 781 Bcfe of proved reserves in multiple sales transactions with various third parties. The sale of these reserves, combined with normal production declines, mechanical failures on certain producing wells and disappointing drilling results, have resulted in our total equivalent production levels declining each quarter since the first quarter of 2002. For 2003, our total equivalent production has declined approximately 117 Bcfe or 38 percent as compared to 2002. In addition, since our depletion rate is determined under the full cost method of accounting, we expect a higher depletion rate as a result of higher finding and development costs experienced this year, coupled with a significantly lower reserve base. After taking into consideration the restatement of our natural gas and oil reserves for prior periods, our unit of production depletion rate was approximately $2.26 per Mcfe and $2.32 per Mcfe for the first and second quarters of 2004. We expect this rate to be approximately $2.48 per Mcfe for the third quarter of 2004. See Item 8, Financial Statements and Supplementary Data, Note 24, for a discussion of our natural gas and oil reserves. For the first eight months of 2004, daily production has averaged 367 MMcfe/d; however, for the month of August 2004, production averaged approximately 325 MMcfe/d. Our future trends in production and our depreciation, depletion and amortization rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and future sales activities relating to our proved reserves.

Production Hedging

We have historically engaged in hedging activities, primarily through natural gas and oil swaps, on our natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on our sales. Because this hedging strategy only partially limits our exposure to changes in commodity prices, we can experience significant volatility in our reported results of operations, financial position and cash flows from period to period. During 2003 and so far in 2004, we did not add additional hedges on our future production. As of December 31, 2003, we have hedged 12,750 BBtu of natural gas in each quarter of 2005 at an average price of $3.31.

Operating Results

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

Production Segment Results	2003	2002 (Restated)[1]	2001 (Restated)[1]
	(In millions, except volumes and prices)		
Operating revenues:			
Natural gas	$ 741	$ 1,091	$ 1,562
Oil, condensate and liquids	160	162	200
Other	9	5	21
Total operating revenues	910	1,258	1,783
Transportation and net product costs	(44)	(52)	(56)
Total operating margin	866	1,206	1,727
Depreciation, depletion and amortization	(377)	(468)	(658)
Production costs[2]	(124)	(182)	(234)
Ceiling test and other charges[3]	(202)	(526)	(609)
General and administrative expenses	(82)	(84)	(63)
Taxes, other than production and income taxes	(1)	(3)	(5)
Total operating expenses[4]	(786)	(1,263)	(1,569)
Operating income (loss)	80	(57)	158
Other income	12	5	5
EBIT	$ 92	$ (52)	$ 163
Volumes, prices and cost per unit:			
Natural gas			
Volumes (MMcf)	156,685	263,749	385,793
Average realized prices including hedges ($/Mcf)[5]	$ 4.73	$ 4.14	$ 4.05
Average realized prices excluding hedges ($/Mcf)[5]	$ 5.38	$ 3.09	$ 4.18
Average transportation costs ($/Mcf)	$ 0.22	$ 0.16	$ 0.07

Production Segment Results	2003	2002 (Restated)[1]	2001 (Restated)[1]
	(In millions, except volumes and prices)		
Oil, condensate and liquids			
Volumes (MBbls)	6,287	7,981	8,787
Average realized prices including hedges ($/Bbl)[5]	$ 25.40	$ 20.31	$ 22.81
Average realized prices excluding hedges ($/Bbl)[5]	$ 25.40	$ 20.28	$ 22.75
Average transportation costs ($/Bbl)	$ 0.89	$ 0.62	$ 0.65
Production cost ($/Mcfe)			
Average lease operating cost	$ 0.47	$ 0.52	$ 0.38
Average production taxes	0.16	0.07	0.15
Total production cost[2]	$ 0.63	$ 0.59	$ 0.53
Average general and administrative expenses ($/Mcfe)	$ 0.42	$ 0.27	$ 0.14
Unit of production depletion cost ($/Mcfe)	$ 1.82	$ 1.47	$ 1.48

(1) Amounts restated include depreciation, depletion, and amortization, and ceiling test and other charges as well as related subtotals and totals. Additionally, unit of production depletion cost has been restated.

(2) Production costs includes lease operating costs and production related taxes (including ad valorem and severance taxes).

(3) Includes ceiling test charges, restructuring and merger-related costs, asset impairments, gain (loss) on long-lived assets and changes in accounting estimates.

(4) Transportation costs are included in operating expenses on our consolidated statements of income.

(5) Prices are stated before transportation costs.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

For the year ended December 31, 2003, EBIT was $144 million higher than in 2002. The increase was primarily due to lower ceiling test and other charges, lower depreciation, depletion and amortization expense and lower production costs, partially offset by lower natural gas, oil, condensate and liquids volumes as a result of asset sales, normal production declines and disappointing drilling results.

Operating Revenues. The following table describes the variance in revenue between 2003 and 2002 due to (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges on our revenues.

Production Revenue Variance Analysis	Variance			
	Prices	Volumes	Hedge	Total
	(In millions)			
Natural gas	$358	$(331)	$(377)	$(350)
Oil, condensate and liquids	32	(34)	—	(2)
Other				4
Operating revenue variance	$390	$(365)	$(377)	$(348)

Our 2003 operating revenues decreased $348 million as compared to 2002 primarily due to lower production volumes. Production volume declines were primarily due to the sale of properties in New Mexico, Texas, Colorado, Utah, offshore Gulf of Mexico, and western Canada, as well as normal production declines and mechanical failures in certain producing wells.

Average realized natural gas prices in 2003, excluding hedges, were $2.29 per Mcf higher than in 2002, an increase of 74 percent. However, more than offsetting the increase in revenues due to higher natural gas prices were $101 million of hedging losses in 2003 as compared to $276 million in hedging gains in 2002 relating to our natural gas hedge positions. These hedging losses and gains represent the difference between our hedge price and the market price at the time the hedge positions were settled. We will recognize a hedging loss in 2004 related to natural gas hedge positions that were de-designated during 2002 at higher prices than the original hedged price. This resulted in a loss that is currently deferred in accumulated other comprehensive income and will be recognized through earnings in 2004 upon physical delivery of the hedged commodity.

Operating Expenses. Total operating expenses were $477 million lower in 2003 as compared with 2002 primarily due to lower ceiling test and other charges, lower depreciation, depletion, and amortization expense and lower production costs.

Ceiling test and other charges were $324 million lower in 2003 compared with 2002. In 2003, we incurred ceiling test charges of $109 million, which included $61 million for our Canadian full cost pool, $34 million for our domestic full cost pool, and $14 million for our other international operations. In addition, in 2003 we recorded a $75 million impairment of the goodwill associated with our Canadian operations. In 2002, we incurred $521 million in ceiling test charges, of which $417 million related to our domestic full cost pool, $91 million to our Canadian full cost pool and $13 million related to our other international assets.

Total depreciation, depletion, and amortization expense decreased by $91 million in 2003 as compared to 2002 primarily due to lower production volumes in 2003 due to the asset sales, normal production declines, and mechanical failures in certain producing wells mentioned above. These lower production volumes reduced our depreciation, depletion and amortization expenses by $172 million. This decrease was partially offset by an increase of $69 million from higher depletion rates as a result of higher finding and development costs in 2003 and a lower reserve base due to asset sales. We also incurred $16 million in 2003 for the accretion of our liability for asset retirement obligations.

Production costs decreased by $58 million in 2003 as compared to 2002 as a result of the asset sales noted above. However, our production cost per unit in 2003 increased by 7 percent or $0.04/Mcfe primarily as a result of higher production taxes in 2003 due to higher natural gas and oil prices and higher tax credits taken in 2002 on high cost natural gas wells.

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

For the year ended December 31, 2002, EBIT was $215 million lower than in 2001. The decrease was primarily due to lower natural gas volumes due to asset sales and normal production declines. Partially offsetting the decrease was lower ceiling test and other charges, lower depreciation, depletion and amortization expense, and lower production costs primarily due to the lower production volumes mentioned above.

Operating Revenues. The following table describes the variance in revenue between 2002 and 2001 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges on our revenues.

Production Revenue Variance Analysis	Variance			
	Prices	Volumes	Hedge	Total
	(In millions)			
Natural gas	$(287)	$(510)	$326	$(471)
Oil, condensate and liquids	(20)	(18)	—	(38)
Other				(16)
Operating revenue variance	$(307)	$(528)	$326	$(525)

Our 2002 operating revenues decreased $525 million as compared to 2001 primarily due to lower production volumes. The volume decline in natural gas and oil, condensate, and liquids were primarily due to the sale of properties in Colorado, Utah and Texas as well as normal production declines.

Average realized natural gas prices, excluding hedges, were $1.09 per Mcf lower than in 2001, a decrease of 26 percent. However, more than offsetting this reduction were $276 million of hedging gains in 2002 as compared to $50 million of hedging losses in 2001 relating to our natural gas hedge positions. These hedging losses and gains represent the difference between our hedge price and the market price at the time the hedge positions were settled.

Operating Expenses. Total operating expenses were $306 million lower in 2002 as compared to 2001 due primarily to lower depreciation, depletion and amortization, lower ceiling test and other charges, and lower production costs, partially offset by higher general and administrative expenses.

Total depreciation, depletion and amortization decreased in 2002 by $190 million as compared to 2001 primarily due to lower production volumes in 2002 due to the asset sales and normal production declines mentioned above. These lower production volumes reduced our depreciation, depletion and amortization expenses by $188 million.

Ceiling test and other charges decreased by $83 million in 2002 as compared with 2001. Our 2002 non-cash full cost ceiling test charges of $521 million included $417 million for our domestic full cost pool, $91 million for our Canadian full cost pool, and $13 million for our other international operations. In 2001, we incurred ceiling test charges of $537 million, of which $257 million related to our domestic full cost pool, $225 million related to our Canadian full cost pool, $50 million related to our Brazilian full cost pool, and $5 million to our other international operations. We also incurred $45 million of merger related costs, $16 million of asset impairments and $10 million of write-downs of materials and supplies following the merger with El Paso in 2001.

Production costs were $52 million lower in 2002 as a result of the asset sales noted above and to lower production taxes in 2002 due to lower natural gas and oil prices and tax credits taken in 2002 on high cost natural gas wells. However, our production costs per unit increased 11 percent or $0.06 per Mcfe due to lower production volumes and an increase in the mix of oil production versus gas production which has a higher operating cost per unit.

General and administrative expenses were $21 million or $0.13 per Mcfe higher than in 2001, an increase of 93 percent on a per unit basis primarily due to higher corporate overhead allocations, offset by higher capitalized costs.

Field Services Segment

Our Field Services segment conducts our midstream activities which includes processing and gathering of natural gas. For the majority of 2003, our assets principally consisted of our consolidated processing assets in south Louisiana.

Processing and Gathering Operations

We attempt to balance earnings in our processing and gathering business through a combination of fixed fee-based and market-based services. A majority of our gathering operations earn margins from fixed-fee-based services. However, some of these 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. Our processing 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 the service provided. 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.

Asset Sales

During 2003, we sold our gathering systems located in Wyoming to Western Gas Resources, Inc. We also sold our midstream assets in the Mid-Continent region to Regency Gas Services, LLC, an investment of Charlesbank Capital Resources, LLC. Our Mid-Continent assets primarily included 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.

Following the sales activities discussed above, our remaining assets now consist primarily of our processing and gathering facilities in south Louisiana. Furthermore, these actions have resulted in significant EBIT reductions.

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

Field Services Segment Results	2003	2002	2001
	(In millions, except volumes and prices)		
Processing and gathering gross margins[1]	$ 59	$ 112	$ 155
Operating expenses	(18)	(44)	(99)
Operating income	41	68	56
Other income (expenses)	(93)	(53)	16
EBIT	$ (52)	$ 15	$ 72
Volumes and Prices:			
Gathering			
Volumes (BBtu/d)	101	628	843
Prices ($/MMBtu)	$ 0.14	$ 0.13	$ 0.14
Processing			
Volumes (inlet BBtu/d)	1,687	1,754	1,966
Prices ($/MMBtu)	$ 0.11	$ 0.12	$ 0.14

(1) Gross margins consist of operating revenues less cost of products sold. We believe this measurement is more meaningful for understanding and analyzing our Field Services operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

For the year ended December 31, 2003, our EBIT was $67 million lower than 2002. Our asset sales in 2003 and 2002 contributed a year over year decrease in our EBIT of $18 million. We also had a net increase of $38 million year over year relating to impairment charges, write-down of goodwill, and net loss on sale of assets and investments.

The decrease in our processing and gathering gross margins for the year ended December 31, 2003, was primarily due to lower margins of $35 million as a result of asset sales which included the Dragon Trail gas processing plant in May 2002, Natural Buttes and Ouray natural gas gathering systems in December 2002, Wyoming gathering assets in January 2003, Mid-Continent gathering and processing assets in June 2003, and $7 million related to the transfer of our Gilmore assets to a subsidiary of El Paso.

Operating expenses for year ended December 31, 2003, were $26 million lower than in 2002. During 2003, we realized $19 million in net gains from the sales of assets noted above versus $35 million in 2002. These sales contributed to lower operating costs and depreciation expense in 2003 totaling $24 million. In addition, we recorded a $14 million loss associated with our write-down of goodwill in 2002.

Other non-operating expenses increased $40 million due to $86 million in impairment charges in 2003 related to our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. The impairment was recorded based on the pending sales of our interests in these investments which closed in August 2004. Partially offsetting this increase were losses on the sale of our investment in the Aux Sable NGL plant and our Blacks Fork natural gas processing plant in 2002 totaling $50 million.

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

For the year ended December 31, 2002, our EBIT was $57 million lower than in 2001. This decrease was the result of lower processing and gathering margins of $43 million of which $37 million was due to lower

NGL prices in 2002 and natural declines in production in 2002, which unfavorably impacted our volumes and margins in the Rocky Mountain and south Louisiana regions. We also experienced lower margins of $6 million related to the sale of our Dragon Trail processing plant in May 2002.

Operating expenses for the year ended December 31, 2002, were $55 million lower than in 2001. The decrease was due to $35 million of gains in 2002 on the sales of our Natural Buttes and Ouray natural gas gathering systems and our Dragon Trail processing plant, merger-related costs of $13 million in connection with our 2001 merger with El Paso and a change in our 2001 estimated environmental remediation liabilities of $9 million. Also contributing to the decrease was $14 million of lower expenses as a result of the sale of our Dragon Trail processing plant and our cost reduction plan in 2002. The decrease was partially offset by a $14 million goodwill impairment that resulted from the sale of assets during 2002.

Other non-operating income for the year ended December 31, 2002, was $69 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 and $6 million of lower equity earnings from Deepwater Holdings as a result of the sale of our interests to GulfTerra in October 2001.

Merchant Energy Segment

Our Merchant Energy segment consists of the ownership and operation of domestic and international power plants, including consolidated plants and equity investments. As part of El Paso's Long-Range Plan, El Paso announced its intent to dispose of a majority of our domestic and international power operations over the next several years. In December 2003, El Paso's Board approved the sale of substantially all of our domestic power plant operations, which we expect to complete in 2004. The future results of our Merchant Energy segment will be impacted by the timing of these sales. Historically, it also had a petroleum markets division. In 2003, El Paso's Board of Directors approved the sale of these petroleum markets operations and, as a result, we reclassified that division as discontinued operations for all periods presented.

Our operations include contracted and merchant power operations and the results of our power restructuring business. Our contracted power operations include power plants that have dedicated power contracts with customers (generally electric utilities and governmental agencies) for the generation and sale of power. Since the long-term sales contracts and long-term fuel contracts in these operations generally contain fixed prices, operating results in this business are fairly stable.

Our merchant power operations include plants that operate during peak periods without dedicated power contracts. Generally, these plants operate when there is demand for their power and when the market price of power exceeds the plant's variable costs of generating power. Many of our merchant plants have contractual obligations, such as transportation capacity contracts, that represent fixed costs for the plant. Our ability to recover these fixed operating costs depends largely on electricity demand and the volume of power generated as well as the margins that can be realized.

In 2001 and 2002, we restructured several above-market, long-term power sales contracts with regulated utilities that were originally tied to older power plants built under PURPA. These contracts were amended so that the power sold to the utilities was not required to be delivered from the specified power generation plant, but could be obtained in the wholesale power market. For a further discussion of our power restructuring activities, see Item 8, Financial Statements and Supplementary Data, Note 12. Since December 31, 2003, we have sold two of our domestic power plants and all of our power restructuring activities for proceeds of approximately $92 million and the assumption by the buyer of approximately $887 million in debt. As a result of our credit downgrades and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities.

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

Merchant Energy Segment Results	2003	2002	2001
		(In millions)	
Gross margin[1]	$ 160	$ 665	$ 42
Operating expenses	(153)	(280)	(83)
Operating income (loss)	7	385	(41)
Other income	17	24	149
EBIT	$ 24	$ 409	$108

(1) Gross margin consists of revenues from our power plants and the initial net gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of those contracts. The cost of fuel used in the power generation process is included in operating expenses.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

For the year ended December 31, 2003, our EBIT was $385 million lower than in 2002. This decrease is due primarily to the fact that we restructured the power sales contracts at our Eagle Point (also known as UCF) and Nejapa power plants in 2002, which resulted in a $436 million gain, net of minority interest and other transaction costs. Also contributing to this decrease was a $41 million decrease in the operating income at our Eagle Point power plant in 2003, following the restructuring of its power contract in March 2002. We also recorded a $43 million impairment of our equity investment in the Bastrop power plant in 2003 based on our anticipated sale of the plant, which was completed in the second quarter of 2004. Partially reducing this 2003 decrease in EBIT was a $64 million increase in the fair value of our UCF restructured power contract in 2003, and a $90 million contract termination fee we paid in 2002 to terminate a steam contract between our Eagle Point power plant and the Eagle Point refinery (which is included in discontinued operations) which has been eliminated in consolidation.

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

For the year ended December 31, 2002, our EBIT was $301 million higher than in 2001. This increase is primarily due to the fact that we restructured the power sales contracts at our Eagle Point (also known as UCF) and Nejapa power plants in 2002, which resulted in a $436 million gain, net of minority interest and other transaction costs. This gain was partially offset by an $18 million write-down of power turbines. In 2002, El Paso reduced its capital expenditure plans related to future development of power projects because of its liquidity concerns, and as a result its ability and intent to use the turbines in its international and domestic power development projects had changed. Also offsetting the increase was a $90 million contract termination fee we paid in 2002 to terminate a steam contract between our Eagle Point power plant and the Eagle Point refinery (which is included in discontinued operations) which has been eliminated in consolidation.

Corporate and Other Expenses, Net

Our Corporate and Other operations include general and administrative functions as well as other miscellaneous businesses.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

For the year ended December 31, 2003, corporate and other net expenses were $34 million lower than in 2002. The decrease was primarily due to (i) $26 million of miscellaneous balance sheet adjustments in 2002 and 2003, (ii) a $10 million increase in interest income from our unconsolidated subsidiaries, (iii) a $6 million write-off of receivables in 2002 resulting from the sale of substantially all of our remaining retail gas stations in 2001, and (iv) $4 million of net gains on sales of aircrafts in 2003 and 2002. Partially offsetting these decreases was $21 million of income from the favorable resolution of non-operating contingent obligations in 2002.

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

For the year ended December 31, 2002, corporate and other expenses, net were $679 million lower than in 2001. The decrease was primarily due to $520 million of merger-related charges in 2001, in connection with our merger with El Paso. Also contributing to the decrease in 2002 were charges of $144 million in 2001 related to increased estimates of environmental remediation and reductions in fair value of spare parts to reflect changes in usability of spare parts inventories based on an ongoing evaluation of our operating standards and plans following the merger.

Interest and Debt Expense

Below is an analysis of our interest and debt expense for each of the three years ended December 31 (in millions):

	2003	2002	2001
Long-term debt, including current maturities	$412	$413	$388
Other interest	6	26	61
Commercial paper	—	—	7
Capitalized interest	(15)	(18)	(36)
Total interest and debt expense	$403	$421	$420

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Interest expense on long-term debt for the year ended December 31, 2003, was $1 million lower than in 2002 due primarily to a $69 million decrease in interest expense resulting from the retirement of $1.7 billion of debt during 2002 and 2003 with an average interest rate of 6.52%, partially offset by a year over year $36 million increase in interest from the debt issued by UCF and Mohawk River Funding IV in mid-2002. Also offsetting this decrease was $23 million of interest on $300 million of new borrowings by ANR in 2003 and $13 million of interest on $300 million of Coastal Finance I preferred securities, which were reclassified as long-term debt as of July 1, 2003.

Other interest for the year ended December 31, 2003 was $20 million lower than in 2002. The decrease was primarily due to a $12 million reduction in interest expense from the retirement of other financing obligations, a $3 million decrease due to a reduction in the factoring of receivables, and a $4 million decrease due to the termination of a marketing sales contract in 2002.

Capitalized interest for the year ended December 31, 2003 was $3 million lower than in 2002 primarily due to lower interest rates in 2003 as compared to 2002.

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

Interest expense on long-term debt for the year ended December 31, 2002, was $25 million higher than in 2001 primarily due to a $37 million increase in interest from the debt issued by UCF and Mohawk River Funding IV in mid-2002. Also contributing to the increase was a $9 million increase in interest related to the Valero lease financing loan, issued in the fourth quarter of 2001, that was outstanding for the entire year in 2002. These increases were partially offset by a $26 million decrease due to the retirement of approximately $1 billion of long-term debt with an average interest rate of 5.6%. 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 $7 million lower than in 2001. The decrease was due to the fact that we discontinued our commercial paper program in 2002.

Other interest for the year ended December 31, 2002, was $35 million lower than in 2001. The decrease was primarily due to a $7 million decrease resulting from the retirement of our other financing obligations, an $18 million decrease in the factoring of receivables, and an $8 million decrease due to the termination of a marketing sales contract during 2002.

Capitalized interest for the year ended December 31, 2002, was $18 million lower than in 2001 primarily due to lower interest rates in 2002 as compared to 2001.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the year ended December 31, 2003, was $41 million, or $32 million higher than in 2002. The increase was primarily due to higher average advances payable to El Paso under our cash management program in 2003. The average advance payables balance increased from $455 million in 2002 to $2,052 million in 2003. The average short-term interest rates for the year increased from 1.9% in 2002 to 2% in 2003.

Affiliated interest expense for the year ended December 31, 2002, was $9 million, or $37 million lower than in 2001. The decrease was primarily due to lower short-term interest rates on decreased average advances payable to El Paso under our cash management program. The average short-term rates for the year decreased from 4.7% in 2001 to 1.9% in 2002. The average advance payables balance decreased from $1 billion in 2001 to $455 million in 2002.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2003, were $18 million lower than in 2002, primarily due to the redemption of Coastal Securities Company Limited preferred stock and the reclassification of Coastal Finance I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150. As a result of this reclassification, we began recording the preferred returns on these securities as interest expense rather than as distributions of preferred interests.

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2002, were $16 million lower than in 2001, primarily due to the redemption of all the preferred interests related to El Paso Oil & Gas Resources, El Paso Oil & Gas Associates and Coastal Limited Ventures. 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.

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 17.

Income Taxes

Income tax benefit for the year ended December 31, 2003, was $57 million resulting in an effective tax rate of (48) percent. For the year ended December 31, 2002, income tax expense was $109 million, resulting in an effective tax rate of 26 percent. Income tax benefit for the year ended December 31, 2001 was $87 million resulting in an effective tax rate of 15 percent. Of the 2003 amount, $105 million related to tax benefits recorded on abandonments and sales of certain of our foreign investments. The effective tax rate for 2003 absent these benefits would have been 41%. Included in the 2001 benefit was a tax charge of $106 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. Taxes on the majority of these estimated additional liabilities were paid in 2001. The effective tax rate for 2001 absent these charges would have been 33 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;
- foreign income/loss taxed at different rates;

• non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;

• abandonments and sales of foreign investments;

• valuation allowances;

• depreciation, depletion and amortization; and

• non-taxable stock dividends.

For a reconciliation of the statutory rate to our effective tax rate, as well as matters that could impact our future tax expense, see Item 8, Financial Statements and Supplementary Data, Note 10.

Discontinued Operations

In 2002 and 2003, El Paso made the decision to eliminate its involvement in our petroleum markets operations and coal mining operations and to sell the related assets and liabilities, and, as a result, we reported these operations as discontinued operations as of December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002 and 2001.

Petroleum Markets Operations

During 2003, El Paso's Board of Directors authorized the sale of substantially all of its petroleum markets operations. Based on its intent to dispose of these operations, we adjusted these assets to their estimated fair value and recognized pre-tax charges during 2003 totaling approximately $1.5 billion, which included $1.1 billion related to our Aruba refinery and $264 million related to the impairment of our Eagle Point refinery. In 2003, we completed sales of $682 million of these assets and completed an additional $905 million in early 2004. We completed the sale of substantially all of our remaining petroleum market assets in 2004.

Coal Mining Operations

In late 2002 and the first quarter of 2003, we sold our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by El Paso's Board of Directors, we recorded impairment charges of $185 million in our loss from discontinued operations during 2002. We have now fully exited our coal mining operations.

For the years ended December 31, the after-tax income (loss) related to our discontinued operations was as follows (in millions):

	Year Ended December 31,		
	2003	2002	2001
Petroleum markets	$(1,298)	$(241)	$(80)
Coal mining	1	(124)	(5)
Total discontinued operations	$(1,297)	$(365)	$(85)

For the year ended December 31, 2003, we reported a loss from our discontinued operations of $1.3 billion. This was primarily due to impairments of long-lived assets of $1.5 billion, including $1.1 billion related to our Aruba refinery and $264 million related to our Eagle Point refinery. In addition, our Aruba refinery continued to generate operating losses of approximately $82 million. These losses resulted from lower throughput at Aruba due primarily to operational difficulties following a fire at the facility in April 2001 and scheduled turnaround maintenance activities. Our losses were partially offset by operating income at our Eagle Point refinery of approximately $42 million. This income resulted from higher margins at Eagle Point due to a widening difference between the price of the crude oil input used by the refinery and the price we sold the refined products produced. This loss was also partially offset by $90 million of gains recorded on the sale of our

Florida terminalling and transportation assets, asphalt facilities and chemical facilities in 2003 and $65 million of business interruption and property damage insurance recoveries related to the Aruba facility fire in 2001.

For the year ended December 31, 2002, we reported a loss from discontinued operations of $365 million. This was primarily due to operating losses of approximately $129 million at our Aruba refinery, resulting from operational difficulties following the fire at the facility. Also contributing to this loss was a $185 million impairment of our coal mining operations and a $91 million impairment of our MTBE chemical processing plant. Our losses were partially offset by operating income at our Eagle Point refinery of approximately $97 million, resulting from higher throughput at Eagle Point during 2002 due to a widening difference between the price of crude oil input used by the refinery and the prices at which we sold the products produced. This loss was also partially offset by $46 million of insurance recoveries in 2002 related to the assets destroyed in the Aruba fire.

For the year ended December 31, 2001, we reported a loss from discontinued operations of $85 million. This loss included $262 million of merger-related costs, asset impairments and other charges associated with our merger with El Paso in 2001. See Item 8, Financial Statements and Supplementary Data, Notes 4 and 5 for a discussion of these merger-related costs and impairments. Also contributing to the loss was an operating loss of $87 million at the Eagle Point refinery as a result of lower margins and throughout. Partially offsetting these losses were $97 million of insurance recoveries related to the fire at the Aruba refinery, operating income of $126 million from our refined products and crude oil marketing activities and $23 million of other income which includes equity earnings and income from the lease of our Corpus Christi refinery to Valero.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 18, incorporated herein by reference.

Critical Accounting Policies

Our critical accounting policies are those accounting policies that involve the use of complicated processes, assumptions and/or judgments in the preparation of our financial statements. We have discussed the development and selection of our critical accounting policies and related disclosures with the audit committee of El Paso's Board of Directors and have identified the following critical accounting policies for the current year.

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 acquisition, development and exploration of natural gas and oil reserves in full cost pools maintained by geographic areas, regardless of whether reserves are actually discovered.

The process of estimating natural gas and oil reserves, particularly proved undeveloped and proved non-producing reserves, is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. As of December 31, 2003, of our total proved reserves, 32 percent were undeveloped and 15 percent were developed, but non-producing. In addition, 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. 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. For further discussions of our reserves as well as the restatement of our historical financial statements as a result of downward revisions to our reserve estimates, see Part I, Item 1, Business, under Production segment and Item 8, Financial Statements and Supplementary Data, Notes 1 and 24.

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. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

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, even though actual 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 and may result in write-downs.

Asset Impairments. The asset impairment accounting rules require us to continually monitor our businesses and the business environment to determine if an event has occurred indicating that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then assess the expected future cash flows against which to compare the carrying value of the asset group being evaluated, a process which also involves judgment. We ultimately arrive at the fair value of the asset which is 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). The assessment of project level cash flows 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 impairment estimates. We recorded impairments of our long-lived assets of $132 million, $36 million and $65 million during the years ended December 31, 2003, 2002 and 2001. We recorded impairments of our discontinued operations of $1.5 billion, $290 million and $103 million during the years ended December 31, 2003, 2002 and 2001. Future changes in the economic and business environment can impact our original and ongoing assessments of potential impairments.

Accounting for Environmental Reserves. We accrue 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 societal and economic factors, and include estimates of associated onsite, offsite and groundwater technical studies, and legal costs. 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 31, 2003, we had accrued approximately $131 million for environmental matters. Our reserve estimates range from approximately $131 million to approximately $252 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($49 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($82 million to $203 million) and the lower end of the range has been accrued.

New Accounting Pronouncements Issued But Not Yet Adopted

See Item 8, Financial Statements and Supplementary Data, Note 2 under *New Accounting Pronouncements Issued But Not Yet Adopted* which is incorporated herein by reference.

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 the 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 SEC 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.

Risks Related to Our Liquidity

We have significant debt, which has impacted and will continue to impact our financial condition, results of operations and liquidity.

We have significant debt of approximately $5 billion as of December 31, 2003 and have significant debt service and debt maturity obligations. Our expected debt maturities for the remainder of 2004, 2005 and 2006 are $49 million, $363 million and $654 million, respectively. If our ability to generate or access cash becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected. See Item 8, Financial Statements and Supplementary Data, Note 16, for a further discussion of our debt.

A breach of the covenants applicable to our debt and other financing obligations could affect our ability to raise capital and could accelerate our debt and other financing obligations and those of our subsidiaries.

Our debt and other financing obligations contain restrictive covenants and cross-acceleration provisions. A breach of any of these covenants could accelerate our long-term debt and other financing obligations and that of some of our subsidiaries, and could preclude some of our subsidiaries from issuing letters of credit and from borrowing under El Paso's $3 billion revolving credit facility. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

Various other financing arrangements entered into by El Paso and its subsidiaries, including us, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The filing of our 2004 Forms 10-Q will cure the event of non-compliance resulting from our failure to file financial statements. In addition, neither we nor any of El Paso's other subsidiaries have received a notice of the default caused by our failure to file our financial statements or the financial statements of El Paso's other subsidiaries also impacted by the restatement. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

We are a wholly owned direct subsidiary of El Paso and its financial condition subjects us to potential risks that are beyond our control.

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The ratings assigned to El Paso's senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody's (with a negative outlook and under review for a possible downgrade) and CCC+ by Standard & Poor's (with a negative outlook). Our senior unsecured indebtedness is rated Caa1 by Moody's (with a negative outlook and under review for a possible downgrade) and CCC+ by Standard & Poor's (with a negative outlook). These ratings have increased our cost of capital and collateral requirements, and could impede our access to capital markets. El Paso has realized substantial demands on its liquidity. El Paso's current ratings are a result, at least in part, of the outlook generally for the consolidated businesses of El Paso and its needs for liquidity.

El Paso has embarked on its Long Range Plan that defines El Paso's future business, targets significant debt reduction, and establishes financial goals. An inability to meet these objectives could adversely affect El Paso's liquidity position, and in turn affect our financial condition.

We participate in El Paso's cash management program, which matches cash surplus and needs for its participating affiliates. In addition, we conduct commercial transactions with some of our affiliates. As of December 31, 2003, we have net payables of approximately $447 million to El Paso and its affiliates. El Paso provides cash management and other corporate services for us. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program, or that our affiliates could pay their obligations to us. However, we would be required to satisfy affiliated company payables, although we do not anticipate that El Paso will require us to repay these payables during 2004. Our inability to access the cash management program, recover any intercompany amounts owed to us, or a demand for payment of our affiliated payables could adversely affect our ability to repay our outstanding indebtedness. For a further discussion of our related party transactions, see Part II, Item 8, Financial Statements and Supplementary Data, Note 22.

Some of our assets are collateral for El Paso's $3 billion revolving credit facility and other financing transactions.

Some of our subsidiaries are subsidiary guarantors of El Paso's $3 billion revolving credit facility and other financing transactions. In connection with their guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the $3 billion revolving credit facility and approximately $300 million of other financing arrangements including leases, letters of credit and other facilities. Our ownership in the above mentioned companies is subject to change if El Paso's lenders under these facilities exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition.

Some of our assets are collateral for El Paso's Western Energy Settlement

One of our subsidiaries has pledged as collateral a portion of its oil and gas properties to support the obligations of some of our affiliates to make payments in connection with the settlement of various lawsuits arising out of the Western Energy Crisis. If our affiliates fail to make those payments, the properties that our subsidiary has pledged would be subject to foreclosure, which could have a material adverse effect on our financial position and liquidity, results of operations and cash flows.

We could be substantively consolidated with El Paso if El Paso were forced to seek protection from its creditors in bankruptcy.

If El Paso were the subject of voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. The equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities and to consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. We believe that any effort to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, we cannot assure you that El Paso and/or its other subsidiaries or their respective creditors would not attempt to advance such claims in a bankruptcy proceeding or, if advanced, how a bankruptcy court would resolve the issue. If a bankruptcy court were to substantively consolidate us with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and liquidity.

Risks Related to Legal and Regulatory Matters

Ongoing litigation and investigations related to our financial statements associated with our reserve estimates could significantly adversely affect our business.

In May 2004, El Paso completed an independent investigation of the reason for or cause of the significant revisions to our natural gas and oil reserves. Following this investigation, we announced that we would restate our historical financial statements for the impact of the previously announced reduction of our proved reserve estimates. As a result of our reduction in reserve estimates, several class action lawsuits were filed against us and several of our subsidiaries. The reserve revisions are also the subject of investigations by the SEC and the U.S. Attorney. These investigations and lawsuits, and possible future claims based on these same facts, may further negatively impact our credit ratings and place further demands on our liquidity. We cannot provide assurance at this time that the effects and results of these or other investigations or of the class action lawsuits will not be material to our financial conditions, results of operations and liquidity.

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 as Superfund sites by the Environmental Protection Agency (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.

Compliance with environmental laws and regulations can require significant costs, such as costs of clean-up and damages arising out of contaminated properties, and failure to comply with environmental laws and regulations may result in fines and penalties being imposed. 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, and these amounts could be material. For additional information concerning our environmental matters, see Part I, Item 3, Legal Proceedings, and Item 8, Financial Statements and Supplementary Data, Note 18.

Costs of other litigation matters could exceed our estimates.

We are involved in various lawsuits in which we or our subsidiaries have been sued. Although we believe we have established appropriate reserves for these liabilities, we could be required to set aside additional reserves in the future and these amounts could be material. For additional information concerning our litigation matters, see Part I, Item 8, Financial Statements and Supplementary Data, Note 18.

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 or because of regulatory pressure, the profitability of our pipeline businesses could be reduced.

In addition, increased regulatory requirements relating to the integrity of our pipelines requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures.

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

Risks Related to Our Business

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

The success of our pipeline business depends, in part, on factors beyond our control.

Most of the natural gas and natural gas liquids we transport 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, which 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 on our pipeline systems:

- future weather conditions, including those that favor alternative energy sources such as hydroelectric power;
- price competition;
- drilling activity and supply availability of natural gas;
- expiration and/or turn back of significant contracts;
- service area competition;
- changes in regulation and action of regulatory bodies;
- credit risk of our customer base;
- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions;
- unfavorable movements in 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. For a further discussion of these matters, see Part I, Item I, Business — Regulated Business, Pipelines Segment, Markets and Competition.

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

- competition by other pipelines, 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 in the areas we serve;
- 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 businesses.

Revenues generated by our transmission, storage, 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 a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas fired power plants. Increased prices could also result from industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies' loss of customer base. The success of our transmission, storage 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, storage and processing through our systems or facilities. If natural gas prices in the supply basins connected to our pipeline systems are higher on a delivered basis to our off-system markets than delivered prices from other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. 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.

Natural gas and oil prices are volatile. A substantial decrease in natural gas and oil prices or changes in basis differentials could adversely affect the financial results of our exploration and production business.

The future financial condition, revenues, results of operations, cash flows, future rate of growth and the carrying value of our natural gas and oil properties depend primarily upon the prices we receive for our natural gas and oil production. Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current world geopolitical conditions. The prices for natural gas and oil are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for, and the supply of, natural gas and oil;
- commodity processing, gathering and transportation availability;
- the level of imports of, and the price of, foreign natural gas and oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- market uncertainty;
- political conditions or hostilities in natural gas and oil producing regions;
- worldwide economic conditions; and
- 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.

Further, because approximately 69 percent of our proved reserves at December 31, 2003 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices than we are to changes in oil prices. Declines in natural gas and oil prices would not only reduce revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could adversely affect the financial results of our production business. Changes in natural gas and oil prices have a significant impact on the calculation of our full cost ceiling test. A significant decline in natural gas and oil prices could result in a downward revision of our reserves and a write-down of the carrying value of our natural gas and oil properties, which could be substantial and would negatively impact our net income and stockholder's equity.

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

In addition to prices, the performance of our natural gas and oil exploration and production businesses is dependent, in part, upon a number of factors that we cannot control, including:

- the results of future drilling activity, including exploratory programs that recently have not been successful;
- 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 conditions;
- increased competition in the search for and acquisition of reserves;
- 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;
- declines in production volumes, including those from the Gulf of Mexico;
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

Our affiliate, El Paso Production Holding Company (El Paso Production), is a wholly owned direct subsidiary of El Paso. El Paso Production, through its subsidiaries engages in the exploration for and the acquisition, development and production of natural gas and oil, primarily in North America. We and El Paso Production do not have an agreement regarding the allocation of business opportunities.

In addition, our officers, directors and personnel also provide services to El Paso Production and its subsidiaries pursuant to our shared services arrangement and therefore share their time and services between us and El Paso Production. These persons may therefore have conflicts of interest between us and El Paso Production.

Our natural gas and oil drilling and producing operations involve many risks and may not be profitable.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks. The nature of the risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured. As a result, we could incur substantial costs that could adversely affect our future results of operations, cash flows or financial condition.

In addition, in our drilling operations we are subject to the risk that we will not encounter commercially productive reservoirs as evidenced by our lack of success in recent exploratory programs. New wells drilled by us may be unproductive, or we may not recover all or any portion of our investment in those wells. Drilling for natural gas and oil can be unprofitable, not only because of dry holes but also due to wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs.

Estimating our reserves, production and future net cash flow is difficult.

Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. As a result, our reserve estimates are inherently imprecise. Also, the use of a 10 percent discount factor for estimating the value of our reserves, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our production business or the natural gas and oil industry, in general, are subject. Any significant variations from the interpretations or assumptions used in our estimates or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially.

The reserve data included in this report represent estimates. You should not assume that the present values referred to in this report represent the current market value of our estimated natural gas and oil reserves. The timing of the production and the expenses from development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Changes in the present value of these reserves could cause a write-down in the carrying value of our natural gas and oil properties, which could be substantial, and would negatively affect our net income and stockholder's equity.

As of December 31, 2003, approximately 32 percent of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of producing reserves.

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

The success of our remaining 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, advantageous power purchase and supply 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;
- the increasing price volatility due to deregulation and changes in commodity trading practices; and
- over-capacity of generation in markets served by the power plants we own or in which we have an interest.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

- Commodity Price Risk
  - Natural gas prices change, impacting the forecasted sale of natural gas in our Production segment;
  - Price spreads between natural gas and natural gas liquids change, making the natural gas liquids we produce in our Field Services segment less valuable;
  - Electricity and natural gas prices change, affecting the value of our power contracts held in our Merchant Energy segment.
- Interest Rate Risk
  - Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed rate debt; and
  - Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions.

We manage these risks by entering into contractual commitments involving physical or financial settlements that attempt to limit the amount of risk or opportunity related to future market movements, primarily related to movements in natural gas prices. Our risk management activities typically involve the use of forward contracts and financial swaps, many of which are derivative financial instruments. A discussion of our accounting policies for derivative instruments is included in Item 8, Financial Statements and Supplementary Data, Notes 2 and 13.

Commodity Price Risk

Our principal commodity price risks exist in our Production segment. Our Production segment attempts to mitigate commodity price risk and to stabilize cash flows associated with its forecasted sales of its natural gas and oil production through the use of derivative natural gas and oil swap contracts entered into with other El Paso affiliates. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks that were outstanding at December 31, 2003 and 2002. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(In millions)		
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2003	$(123)	$(147)	$(24)	$(99)	$24
December 31, 2002	$(144)	$(190)	$(46)	$(98)	$46

The derivatives described above do not hedge all of our commodity price risk related to our forecasted sales of our natural gas production and as a result, we are subject to commodity price risks on our remaining forecasted natural gas production.

Interest Rate Risk

Debt

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, 2003 and 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, 2003								December 31, 2002	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(Dollars in millions)									
Liabilities:										
Long-term debt and other financing obligations, including current portion — fixed rate	$300	$251	$541	$ 51	$474	$3,463	$5,080	$4,992	$4,648	$3,931
Average interest rate	6.9%	9.3%	7.2%	7.9%	7.2%	8.0%				
Long-term debt, including current portion — variable rate	$ 12	$111	$111	$ 7			$ 241	$ 241	$ 706	$ 706
Average interest rate	2.1%	4.0%	4.0%	2.1%						

Derivatives from Power Contract Restructuring Activities

Derivatives associated with our power contract restructuring business in our Merchant Energy segment are valued using estimated future market power prices and a discount rate that considers the appropriate U.S. Treasury rate plus a credit spread specific to the contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in value that can be realized in a current transaction between willing parties. Since September 30, 2002, in order to provide for market risk, we have not reflected the increase in value that would result from decreases in U.S. Treasury rates because we believe the resulting increase in the value of these non-trading derivatives could not be realized in a current transaction between willing parties. Had we reflected the actual U.S. Treasury yields as of December 31, 2003 in our valuation, the value of our third party non-trading derivatives would have been higher by approximately $87 million. As of December 31, 2003, a ten percent increase or decrease in the discount rate used to value third-party positions would result in an increase (decrease) in the fair value of these derivative contracts of $(37) million and $39 million. As a result of the sale of UCF and Mohawk River Funding IV in 2004, our sensitivity to interest rate changes in these derivatives was eliminated.

Foreign Currency Exchange Rate Risk

Several of our international power plants in Asia and Central America have long-term power sales contracts that are denominated in the local country's currencies. As a result, we are subject to foreign currency exchange risk related to these power sales contracts. We do not believe that this exposure is material to our operations and have not chosen to mitigate this exposure.

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 CGP COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2003	2002 (Restated)	2001 (Restated)
Operating revenues			
Pipelines	$ 918	$ 934	$1,054
Production	910	1,258	1,783
Field Services	356	460	894
Merchant Energy	238	1,204	43
Corporate and eliminations	(48)	(30)	190
	2,374	3,826	3,964
Operating expenses			
Cost of products and services	509	1,050	1,121
Operation and maintenance	540	777	819
Merger-related costs	—	—	787
Depreciation, depletion and amortization	517	630	836
Ceiling test charges	109	521	537
Loss (gain) on long-lived assets	97	(7)	69
Taxes, other than income taxes	82	78	141
	1,854	3,049	4,310
Operating income (loss)	520	777	(346)
Earnings (losses) from unconsolidated affiliates	(12)	113	220
Other income	66	70	81
Other expenses	5	(70)	(18)
Interest and debt expense	(403)	(421)	(420)
Affiliated interest expense, net	(41)	(9)	(46)
Distributions on preferred interests of consolidated subsidiaries	(17)	(35)	(51)
Income (loss) before income taxes	118	425	(580)
Income taxes	(57)	109	(87)
Income (loss) from continuing operations	175	316	(493)
Discontinued operations, net of income taxes	(1,297)	(365)	(85)
Extraordinary items, net of income taxes	—	—	(11)
Cumulative effect of accounting changes, net of income taxes	(12)	14	—
Net loss	$(1,134)	$ (35)	$ (589)

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2003	December 31, 2002 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ 150	$ 128
Accounts and notes receivable		
Customer, net of allowance of $37 in 2003 and $21 in 2002	309	400
Affiliates	442	521
Other	87	133
Inventory	58	61
Assets from price risk management activities	97	102
Assets of discontinued operations	1,369	2,154
Other	138	162
Total current assets	2,650	3,661
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	8,304	7,744
Pipelines	6,478	6,522
Power facilities	372	460
Gathering and processing systems	151	279
Other	119	93
	15,424	15,098
Less accumulated depreciation, depletion and amortization	8,678	8,471
Total property, plant and equipment, net	6,746	6,627
Other assets		
Investments in unconsolidated affiliates	1,312	1,505
Assets from price risk management activities	845	956
Goodwill and other intangible assets, net	413	475
Assets of discontinued operations	—	1,911
Other	443	420
	3,013	5,267
Total assets	$12,409	$15,555

See accompanying notes.

EL PASO CGP COMPANY

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

	December 31,	
	2003	2002 (Restated)
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 197	$ 208
Affiliates	110	87
Other	238	261
Short-term financing obligations, including current maturities	310	369
Notes payable to affiliates	906	2,374
Liabilities from price risk management activities	43	216
Liabilities of discontinued operations	658	1,373
Other	320	273
Total current liabilities	2,782	5,161
Long-term financing obligations, less current maturities	5,011	4,985
Other		
Liabilities from price risk management activities	81	24
Deferred income taxes	732	1,193
Liabilities of discontinued operations	—	87
Other	351	239
	1,164	1,543
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	—	400
Minority interests of consolidated subsidiaries	107	114
	107	514
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	3,136	1,616
Retained earnings	224	1,875
Accumulated other comprehensive loss	(15)	(139)
Total stockholder's equity	3,345	3,352
Total liabilities and stockholder's equity	$12,409	$15,555

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2003	2002 (Restated)[1]	2001 (Restated)[1]
Cash flows from operating activities			
Net loss	$(1,134)	$ (35)	$ (589)
Less net loss from discontinued operations, net of income taxes	(1,297)	(365)	(85)
Net income (loss) from continuing operations	163	330	(504)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	517	630	836
Ceiling test charges	109	521	537
(Earnings) losses from unconsolidated affiliates, adjusted for cash distributions	102	28	(103)
Deferred income tax expense (benefit)	(139)	137	(137)
Loss (gain) on long-lived assets	97	(7)	69
Extraordinary items	—	—	11
Cumulative effect of accounting changes	12	(14)	—
Non-cash portion of merger-related costs and changes in estimates	—	—	858
Other non-cash income items	(3)	46	27
Asset and liability changes			
Accounts and notes receivable	438	(469)	(448)
Accounts payable	(91)	(330)	497
Inventory	—	54	5
Changes in trading price risk management activities	22	(480)	25
Other asset and liability changes			
Assets	(73)	178	485
Liabilities	30	(98)	(397)
Cash provided by continuing operations	1,184	526	1,761
Cash provided by (used in) discontinued operations	(40)	(271)	191
Net cash provided by operating activities	1,144	255	1,952
Cash flows from investing activities			
Additions to property, plant and equipment	(985)	(1,394)	(2,077)
Equity investments	(9)	(45)	(133)
Net proceeds from the sale of assets	324	1,518	274
Net proceeds from the sale of investments	60	167	347
Net change in restricted cash	(18)	(59)	—
Repayment of notes receivable from affiliates	(8)	(102)	18
Net cash paid for acquisitions, net of cash acquired	—	45	(232)
Other	(35)	(64)	1
Cash provided by (used in) continuing operations	(671)	66	(1,802)
Cash provided by (used in) discontinued operations	427	(163)	(212)
Net cash used in investing activities	(244)	(97)	(2,014)
Cash flows from financing activities			
Net repayments under commercial paper and short-term credit facilities	—	(30)	(765)
Capital contribution from parent company	1,500	—	—
Net proceeds from the issuance of long-term debt and other financing obligations	288	882	340
Payments to retire long-term debt and other financing obligations	(638)	(1,240)	(572)
Payments to preferred interest and minority interest holders	(100)	(510)	—
Dividends paid	(517)	—	(13)
Net proceeds from issuance of minority interests in subsidiaries	—	33	139
Net change in notes payable to unconsolidated affiliates	(7)	(56)	—
Net change in affiliated advances payable	(1,404)	1,317	889
Contributions from (distributions to) discontinued operations	387	(995)	99
Other	—	(6)	8
Cash provided by (used in) continuing operations	(491)	(605)	125
Cash provided by (used in) discontinued operations	(387)	444	15
Net cash provided by (used in) financing activities	(878)	(161)	140
Change in cash and cash equivalents	22	(3)	78
Less change in cash and cash equivalents related to discontinued operations	—	10	(6)
Change in cash and cash equivalents from continuing operations	22	(13)	84
Cash and cash equivalents			
Beginning of period	128	141	57
End of period	$ 150	$ 128	$ 141

[1] Cash flows from continuing operating, investing and financing activities were restated. However, the total cash flows from continuing operations for 2002 were unaffected.

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY

	For the Years Ended December 31,					
	2003		2002 (Restated)		2001 (Restated)	
	Shares	Amount	Shares	Amount	Shares	Amount
	(In thousands of shares and millions of dollars)					
Preferred stock, par value 33⅓¢ per share, authorized 50,000 shares cumulative convertible preferred						
$1.19, Series A:						
Balance at beginning of year	—	$ —	—	$ —	52	$ —
Converted to El Paso common stock	—	—	—	—	(52)	—
Balance at end of year	—	—	—	—	—	—
$1.83, Series B:						
Balance at beginning of year	—	—	—	—	51	—
Converted to El Paso common stock	—	—	—	—	(51)	
Balance at end of year	—	—	—	—	—	—
$5.00, Series C:						
Balance at beginning of year	—	—	—	—	26	—
Converted to El Paso common stock	—	—	—	—	(26)	—
Balance at end of year	—	—	—	—	—	—
Class A common stock, par value 33⅓¢ per share, authorized 2,700 shares						
Balance at beginning of year	—	—	—	—	311	—
Converted to El Paso common stock	—	—	—	—	(311)	—
Balance at end of year	—	—	—	—	—	—
Common stock, par value 33⅓¢ per share, authorized 500,000 shares						
Balance at beginning of year	1	—	1	—	219,605	73
Exercise of stock options	—	—	—	—	86	—
Conversion to El Paso common stock	—	—	—	—	(219,690)	(73)
Balance at end of year	1	—	1	—	1	—
Additional paid-in capital						
Balance at beginning of year		1,616		1,305		1,044
Capital contribution from El Paso		1,524		309		278
Other		(4)		2		(17)
Balance at end of year		3,136		1,616		1,305
Retained earnings						
Balance at beginning of year		1,875		1,910		2,499
Net loss for period		(1,134)		(35)		(589)
Dividends to parent		(517)		—		—
Balance at end of year		224		1,875		1,910
Accumulated other comprehensive income (loss)						
Balance at beginning of year		(139)		283		(8)
Other comprehensive income (loss)		124		(422)		291
Balance at end of year		(15)		(139)		283
Treasury stock, at cost						
Balance at beginning of year	—	—	—	—	(4,395)	(132)
Retirement of treasury shares					4,395	132
Balance at end of year	—	—	—	—	—	—
Total		$ 3,345		$3,352		$3,498

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2003	2002 (Restated)	2001 (Restated)
Net loss	$(1,134)	$ (35)	$(589)
Foreign currency translation adjustments	112	(14)	(27)
Minimum pension liability accrual (net of income tax of $1 in 2003 and $7 in 2002)	(5)	(12)	—
Net gains (losses) from cash flow hedging activities:			
Cumulative effect of transition adjustment (net of income tax of $248)		—	(459)
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $24 in 2003, $140 in 2002 and $398 in 2001)	(42)	(240)	728
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $34 in 2003, $87 in 2002 and $27 in 2001)	59	(156)	49
Other comprehensive income (loss)	124	(422)	291
Comprehensive loss	$(1,010)	$(457)	$(298)

See accompanying notes.

1. Restatement of Historical Financial Statements and Liquidity

Restatement of Historical Financial Statements

In February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. At the same time, our independent reserve engineers completed their estimates of our proved reserves. Overall, our internally prepared reserve estimates were within 5 percent of the total of the estimates of our independent reserve engineers. The proved reserve estimates as of December 31, 2003 indicated a 1.0 Tcfe or approximate 47 percent downward revision in our proved natural gas and oil reserves was needed. Given the size of this revision, the Audit Committee of El Paso's Board of Directors initiated an independent investigation to be conducted by an outside law firm to determine the factors that contributed to this significant downward revision. The scope of the investigation included (1) assessing the reasons for the downward revisions, (2) evaluating the internal controls associated with the booking of reserves, (3) suggesting any recommendations with regard to improvements in internal controls and processes and (4) recommending any remedial actions that may be required. The investigation included the completion of more than 200 interviews and the review of more than 100,000 documents. Based on the investigation results, we concluded that a material portion of the negative reserve revisions should have been reflected in periods prior to 2003 and would require a revision of the historical reserve estimates included in our supplemental natural gas and oil operations data. Quantities of proven natural gas and oil reserves are used in determining financial statement amounts, including ceiling test charges, depletion expense and gains and losses on natural gas and oil property sales. The revision of our historical reserve estimates required the restatement of the financial statement information derived from these estimates. The investigation found that certain personnel used aggressive, and at times, unsupportable methods to book proved reserves. In some instances, certain personnel provided historical proved reserve estimates that they knew or should have known were incorrect at the time they were reported. The investigation also found that we did not, in some cases, maintain adequate documentation and records to support historically booked reserves. Based on the results of the investigation, we (a) reviewed alternatives with respect to the method or methods to be used to restate our reserve amounts in prior periods and (b) assessed and implemented remedial actions related to our management structure, internal control environment and internal control processes.

Restatement Methodology

Because of concerns over our historical documentation supporting reserves and the aggressive, and sometimes unsupportable methods that were used by personnel in booking proved reserves, the methodology we adopted to restate our reserves for the years ended December 31, 2001 and 2002 and the nine months ended September 30, 2003, was a reserve reconstruction approach. Under this method, we utilized the estimated proved reserves as of December 31, 2003 that were derived from our review completed in February 2004, and then determined historical reserves by adjusting these reserves for actual historical production data and other known data to determine the reconstructed estimates of reserves at each period end. The basic assumption underlying our methodology was that the December 31, 2003 reserve report represented the most recent, reliable and available information and was our best estimate of proved reserves. That report, therefore, became the basis of our historical reserve reconstruction. We then created a reconstruction process by adding actual production volumes in prior periods, on a well by well basis, with adjustments for assets sold (the more significant sales were re-evaluated by one of our independent reserve engineers since the proved reserves that were sold were not in the December 31, 2003 reserve report and needed to be re-evaluated given the findings in the investigation) and other known information during the period such as cost and capital spending during the restatement period.

We applied the approach described above back to December 31, 2000. However, for periods prior to December 31, 2000, which were necessary to determine the impact of the reserve restatement on beginning stockholder's equity as of January 1, 2001, we did not have access to the necessary detailed electronic records to apply this methodology. This was due, in part to some of the documentation issues identified in the investigation, and numerous changes in personnel immediately following past mergers, which impacted our ability to locate that historical documentation. As a result, we used our December 31, 2000 reserve levels determined by the reconstruction approach described above as the foundation for estimating reserves and related cash flows (for ceiling test purposes) for periods prior to December 31, 2000. This estimation approach involved the use of a "reserve over production ratio" based on the reconstructed December 31, 2000 reserve estimates. The reserve over production ratio provided the estimated life of reserves based on production levels. We applied that ratio to the actual historical period production levels to calculate estimated historical reserves for each period. In determining the reserve over production ratio to use for each period, historical prices were considered since at different pricing levels, varying levels of reserves are economical to produce, which also impacted capital cost, operating cost and revenue assumptions in determining cash flows that would be derived from reserves.

Overall, our restatement approach allowed us to re-calculate reasonable proved reserve estimates at the end of each quarter over the last five years. Once we determined the historical reserve levels, we then calculated our estimated future net cash flows at the end of each quarter. These revised quarterly proved reserves and the resulting discounted net cash flows were then used to perform the ceiling test, calculate our depreciation, depletion and amortization rate, income taxes and evaluate gain or loss recognition on natural gas and oil property sales for each quarter. Finally, we assessed the adequacy of our overall approach based on historical prices and historically capitalized costs leading up to the earliest period in which our restatement was performed. Based on that assessment, we believe the amount recorded as a retained earnings adjustment on January 1, 1999 reasonably reflects the financial statement impact of our restated reserve levels that would have occurred prior to that time.

We believe the approach used to restate our historical reserves is a reasonable approach and is appropriate in these circumstances. It is based on a current, thoroughly reviewed and well documented reserve study and reflects actual historical data. However, it does have some limitations. First, the restated reserve levels and reported earnings do not incorporate normal positive or negative revisions in reserves that could have resulted for reasons such as mechanical failures, changes in estimates or the impact of actual drilling results on proved undeveloped reserves. These are normally occurring changes to reserves estimates that, because of the methodology we used, will not be reflected during the year they actually occurred. Rather, they will be part of our beginning retained earnings adjustments. Overall, we believe their effects on our reported results would be similar. Second, because we had to use a variation of the methodology for the years 1999 and 2000, to determine the impact on our retained earnings at January 1, 2001, the restated reserves for these periods may not be comparable to the reserve amounts that would have resulted from an actual reconstruction and none of the periods would be identical to a completely re-engineered approach. Overall, however, we believe our approach, given the results of the investigation and documentation issues discussed above, provides a reasonable approach to revising our historical reserve data that presents our related historical financial results in accordance with generally accepted accounting principles.

We also considered other restatement methodologies such as re-engineering specific production and reserve areas to determine, in hindsight, where previous estimates should have been adjusted in specific periods. We rejected this approach for several reasons. First, this method would not have produced, in our view, a more accurate result than the method we adopted, particularly given our concerns with respect to the timing of when the reserves were originally recorded. Second, it was very difficult to make reasonable assessments of how specific reserves should have been booked at a particular time without being influenced by subsequent data, especially in light of the assumptions that had already been made in the reserve estimation process. Third, the investigation identified that (a) a large number of personnel were responsible for making reserve estimates and that there was not a consistent or centralized approach used in the reserve estimation process, including the assumptions used in the process or the documentation generated in support of these assumptions and (b) there was a lack of controls over inputs into the reserve data base. As a result of such factors, the integrity of the data could not be reasonably relied upon for a detailed re-engineering of reserves. Finally, the findings of the independent investigation identified that there was inadequate detailed historical, technical documentation to support the booking of certain reported reserves. Consequently, without such detailed documentation, it would be extremely difficult, and in some cases impossible, to determine with precision the appropriate time that specific reserves should have been removed from the proved reserves category.

Our reserve restatement methodology resulted in the following revisions to our proved natural gas and oil reserves (Bcfe) (Unaudited):

	As of December 31,					
	2002		2001		2000	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
U.S.						
Onshore	1,413	758	3,415	1,499	3,512	1,422
Offshore	400	205	532	233	820	371
Coal Seam	153	95	51	39	77	58
Total U.S.	1,966	1,058	3,998	1,771	4,409	1,851
International						
Canada	167	110	252	113	190	33
Brazil	100	—	87	—	120	—
Other	52	5	—	—	—	—
Total International	319	115	339	113	310	33
Natural Gas Systems	—	—	183	183	175	175
Total Worldwide	2,285	1,173	4,520	2,067	4,894	2,059

The restatement of our proved reserves also impacted previously reported items in our supplemental information on our natural gas and oil activities, including the classification of costs incurred in natural gas and oil activities between exploration or development cost. For a further discussion of our natural gas and oil reserves, see Note 25, Supplemental Natural Gas and Oil Operations. Also, for a discussion of a restatement related to our original classification of a contribution by El Paso of interests in one of its subsidiaries to us, see Note 22.

Financial Impact of Restatement

The total cumulative impact of the restatement that affected our stockholder's equity as of September 30, 2003 was a reduction of approximately $1.1 billion, which includes a reduction in beginning stockholder's equity as of January 1, 2001 of $1.1 billion. Of the adjustment to beginning stockholder's equity $11 million, net of tax, related to higher depreciation, depletion and amortization expense in 2000, $80 million, net of tax, to higher ceiling test charges offset partially by lower depreciation, depletion and amortization expense in 1999 and $1 billion, net of tax, related to the impacts of the reserve revision restatement on beginning stockholder's equity as of January 1, 1999. We did not reconstruct our reserves to periods prior to December 31, 1998. We believe our approach and the five year period through which our reconstruction was performed was reasonable in light of the circumstances surrounding our restatement.

As to the individual financial statement line items, our historical financial statements for the years ended December 31, 2002 and 2001, for each of the quarters in those years and for each quarter and the first nine months of 2003 reflect the effects of the restatement on (i) the calculation of our historical depletion expense and its effect on our cumulative effect of accounting changes for our asset retirement obligations, (ii) the amount of our quarterly full cost ceiling test charges on amounts capitalized in our natural gas and oil full cost pools, (iii) the amounts of gains or losses recorded on long-lived assets sold, and (iv) the amounts of income taxes. We did not amend our annual report on Form 10-K for the years ended December 31, 2002 and 2001, or our quarterly reports on Form 10-Q for any periods prior to December 31, 2003, and the financial statements and related financial information contained in those reports should no longer be relied upon. A summary of the effects of the restatement on reported amounts for the years ended December 31, 2002 and 2001, and for the quarterly periods during the three year period ended December 31, 2003 is presented below. The quarterly period information for 2001 is being provided for supplemental purposes only. Also, the information in the quarterly data below represents only those income statement and balance sheet line items affected by the restatement. For additional supplemental quarterly information, see Note 23.

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Income Statement:				
Depreciation, depletion and amortization	$ 608	$ 630	$ 632	$ 836
Ceiling test charges[(1)]	245	521	115	537
Loss (gain) on long-lived assets	694	(7)	69	69
Operating income (loss)	463	777	280	(346)
Income taxes (benefit)	(47)	109	139	(87)
Net loss	(283)	(35)	(188)	(589)
Balance Sheet:				
Property, plant and equipment, net	$8,284	$6,627	$9,903	$7,631
Investments in unconsolidated affiliates	1,528	1,505	1,821	1,798
Stockholder's equity[(2)]	4,300	3,352	4,970	3,498

(1) Ceiling test charges for each period were calculated based on a comparison of the overall capitalized costs to the estimated future cash flows from reserves using our restated reserve levels at then current prices and adjusting these cash flows for the impact of hedges. These calculations were performed quarterly for each period restated.

(2) The impact on stockholder's equity for the year ended December 31, 2001 includes the restatement impacts on depreciation, depletion and amortization and ceiling test charges during that year, as well as the adjustment to opening retained earnings for the effects of the restatement on years prior to 2001.

	Quarters Ended (Unaudited)					
	March 31, 2003		June 30, 2003		September 30, 2003	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)					
Depreciation, depletion and amortization[(1)]	$137	$128	$ 143	$ 129	$137	$129
Ceiling test charges	—	1	—	20	—	80
Operating income[(1)]	268	276	213	207	117	45
Income taxes (benefit)	12	72	77	13	(5)	(30)
Cumulative effect of accounting changes, net of income taxes	(21)	(12)	—	—	—	—
Net loss[(1)]	(55)	(98)	(942)	(884)	(23)	(69)

(1) Our "as reported" depreciation, depletion and amortization, operating income, and income taxes (benefit) differ from those amounts originally included in our March 31, 2003 Form 10-Q by $(13) million, $262 million and $29 million due to reclassifications associated with our discontinued operations and other minor reclassifications, which had no impact on previously reported net income.

	Quarters Ended (Unaudited)							
	March 31, 2002		June 30, 2002		September 30, 2002		December 31, 2002	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)							
Depreciation, depletion and amortization	$ 181	$ 194	$148	$ 158	$129	$137	$ 150	$141
Ceiling test charges	10	4	233	514	—	—	2	3
Loss (gain) on long-lived assets	(11)	(11)	(10)	(10)	1	1	714	13
Operating income (loss)	693	597	94	(198)	165	156	(489)	222
Income taxes (benefit)	162	158	5	(1)	22	(62)	(236)	14
Net income (loss)	394	392	(88)	(373)	(56)	19	(533)	(73)

	Quarters Ended (Unaudited)							
	March 31, 2001		June 30, 2001		September 30, 2001		December 31, 2001	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)							
Depreciation, depletion and amortization	$ 144	$ 173	$167	$ 212	$163	$ 246	$158	$205
Ceiling test charges	—	115	—	66	115	346	—	10
Operating income (loss)	(278)	(422)	53	(58)	145	(169)	360	303
Income taxes (benefit)	(25)	(73)	(6)	(245)	6	117	164	114
Net income (loss)	(347)	(443)	(65)	63	36	(389)	188	180

The restatement of our historical reserve estimates and our historical financial information derived from those estimates has resulted in a delay in the filing of these annual financial statements and has resulted or will result in a delay in the filing of our Forms 10-Q for the quarterly periods ended March 31, 2004, June 30, 2004 and September 30, 2004. Furthermore, these restatements, and ongoing reviews and investigations by the SEC, the U.S. Attorney and other regulators into these restatements, could further limit or delay our ability to quickly access the capital markets in the near term.

The restatement will result in a lower depletion rate and reduced exposure to ceiling test charges in the future than would have been the case absent the restatement. In addition, the restatement did not have any impact on our consolidated cash flows.

Liquidity Update

We rely on cash generated from our internal operations and loans from El Paso through its cash management program as our primary sources of liquidity, as well as asset sales and capital contributions from El Paso. We expect that our future funding for working capital needs, capital expenditures and debt service will continue to be provided from some or all of these sources. Each of these sources is 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. Cash generated by future asset sales may depend on the overall economic conditions of the industries served by these assets, the condition and location of the assets and the number of interested buyers.

El Paso is a significant source of liquidity to us, and we participate in its cash management program. Under this program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically and consistently borrowed cash from El Paso under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to El Paso via the cash management program based on its expected cash needs. On December 31, 2003, El Paso authorized a capital contribution of $1.5 billion to us and as of December 31, 2003, we had a note payable to El Paso of $906 million related to this program. This note is classified as a current liability in our balance sheet because it is due upon demand. Our ability to rely on advances from El Paso can be impacted by its credit standing, its requirement to repay debt and other financing obligations, and the cash demands from other parts of its business. If El Paso were unable to meet its liquidity needs, we would not have access to this source of liquidity. Furthermore, we would be required to repay affiliated company payables, if demanded. However, we do not anticipate that El Paso will require us to repay these payables during 2004.

In February 2004 El Paso completed the December 31, 2003 reserve estimation process for its proved natural gas and oil reserves, which included reserves in our Production segment. As a result of this review, El Paso announced that it was significantly reducing its proved natural gas and oil reserve estimates, including our reserves. After an investigation into this matter, El Paso concluded that a restatement of its historical financial statements, as well as ours, was required.

El Paso believes that a material restatement of its financial statements would have constituted events of default under its $3 billion revolving credit facility and various other financing transactions; specifically under the provisions related to representations and warranties on the accuracy of its historical financial statements and on El Paso's debt to capitalization ratio. During 2004, El Paso received several waivers on its $3 billion revolving credit facility and these other financing transactions to address the restatement. These waivers continue to be effective. El Paso also received an extension of time with various lenders until November 30, 2004 to file its first and second quarter 2004 Forms 10-Q, which it expects to meet. If El Paso is unable to file its Forms 10-Q by that date and it is not able to negotiate an additional extension of the filing deadline, the $3 billion revolving credit facility and various other financing transactions could be accelerated. As part of obtaining its waivers, El Paso also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default and limitations on the ability of El Paso and its subsidiaries to repay indebtedness scheduled to mature after June 30, 2005. Although two of our subsidiaries (ANR and CIG) are eligible to borrow under El Paso's $3 billion revolving credit facility, they do not have any borrowings or letters of credit outstanding under that facility. Based upon a review of the provisions of our indentures and the financing agreements, we believe that a default on El Paso's $3 billion revolving credit facility would not result in an event of default under our other debt agreements unless such default resulted in the acceleration of El Paso's $3 billion revolving credit facility or other transactions collateralized by the same assets and our subsidiaries failed to perform their obligations under their guarantees of such debt.

Various other financing arrangements entered into by El Paso and it's subsidiaries, including us, include covenants that require us to file financial statements within specified time periods. Non-compliance with these covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the default can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The filing of our first and second quarter 2004 Forms 10-Q will cure the events of non-compliance resulting from our failure to file financial statements. We have not received a notice of the default caused by our failure to file our financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

If El Paso were subject to voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. We believe that claims to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, there is no assurance that El Paso and/or its other subsidiaries or their creditors would not advance such a claim in a bankruptcy proceeding. If we were to be substantively consolidated in a bankruptcy proceeding with El Paso and/or its other subsidiaries, it could have a material adverse effect on our financial condition and our liquidity.

Some of our subsidiaries are subsidiary guarantors of El Paso's $3 billion revolving credit facility and other financing transactions. In connection with their guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the $3 billion revolving credit facility and approximately $300 million of other financing arrangements including leases, letters of credit and other facilities. Our ownership in the above mentioned companies is subject to change if El Paso's lenders under these facilities exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition. In addition, one of our subsidiaries has pledged as collateral a portion of its natural gas and oil properties to support the obligations of some of our affiliates to make payments in connection with the settlement of various lawsuits arising out of the Western Energy Crisis. If our affiliates fail to make those payments, the properties that our subsidiary has pledged would be subject to foreclosure, which could have a material adverse effect on our financial position, results of operations and cash flows.

We have cross-acceleration provisions in our long-term debt-agreements which, if triggered, could result in the acceleration of our debt. The most restrictive indenture has a cross-acceleration threshold of $5 million. The acceleration of our long-term debt would adversely affect our liquidity position and, in turn, our financial condition.

We believe we will generate sufficient funds through our operations, asset sales, financing activities and advances from El Paso to meet all of our cash needs.

2. Summary of 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 results for all periods presented reflect our petroleum markets and coal mining businesses as discontinued operations. Additionally, 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 stockholder's 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 in *New Accounting Pronouncements 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 accounting principles generally accepted in the U.S. 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 pipelines and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Effective December 31, 2003, CIG and WIC re-applied the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (see Note 15 for a further discussion). ANR discontinued the application of SFAS No. 71 in 1996. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, postretirement employee benefit plans, and other costs included in, or expected to be included in, future rates.

We perform an annual review to assess the applicability of the provisions of SFAS No. 71 to our financial statements, the outcome of which could result in the re-application of this accounting in some of our regulated systems or the discontinuance of this accounting in others.

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 restricted cash in other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of December 31, 2003 we had $36 million of restricted cash in other current assets and $43 million in other non-current assets and as of December 31, 2002, we had $28 million of restricted cash in other current assets and $32 million in other non-current assets.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts and notes 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 materials and supplies and natural gas in storage. We classify all inventory as current or non-current based on whether it will be sold or used in the normal operating cycle of the assets, to which it relates, which is typically within the next twelve months. We use the average cost method to account for our inventories. We value all inventory at the lower of its cost or market value.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. 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.

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

Type	Method	Depreciable Lives (In years)
Regulated interstate systems		
SFAS No. 71[1]	Composite	3-51
Non-SFAS No. 71	Straight-line	1-64
Unregulated systems		
Transmission and storage facilities	Straight-line	59
Power facilities	Straight-line	7-20
Gathering and processing systems	Straight-line	4-40
Transportation equipment	Straight-line	3-5
Buildings and improvements	Straight-line	14-40
Office and miscellaneous equipment	Straight-line	3-10

(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 rate settlements 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, with any remaining gain or loss 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. Amounts capitalized related to interest costs on debt during the years ended December 31, 2003, 2002 and 2001, were $15 million, $18 million and $36 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. These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity financed construction 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 its carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of the asset's carrying value based on its ability to generate future cash flows on an undiscounted basis. 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. Our fair value estimates are generally based on preliminary market data obtained through the early stages of the sales process and an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors. We also reclassify the asset or assets as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have any continuing involvement in the cash flows of those assets after they are sold.

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, development and exploration 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, asset retirement costs and capitalized interest. 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. These costs are generally expensed under successful efforts when the determination is made that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool which is then periodically assessed for recoverability as discussed below.

We amortize capitalized costs using the unit of production method over the life of our proved reserves. Capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in the amortizable base. Beginning January 1, 2003, we began capitalizing asset retirement costs associated with proved developed natural gas and oil reserves into our full cost pool, pursuant to the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations* as discussed below.

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 ceiling test charges. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

When we sell or convey interests (including net profits interests) in our natural gas and oil properties, we reduce our reserves for the amount attributable to the sold or conveyed interest. 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.

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, and whenever an event occurs that indicates that an impairment may have occurred. We adopted these standards on January 1, 2002 and stopped amortizing goodwill. The initial impairment tests we performed as of January 1, 2002 indicated no impairment of our goodwill.

The net carrying amounts of our goodwill as of December 31, 2003 and 2002, and the changes in the net carrying amounts of goodwill for the years ended December 31, 2003 and 2002 for each of our segments are as follows:

	Pipelines	Production	Field Services	Total
		(In millions)		
Balances as of January 1, 2002	$413	$ 61	$ 14	$488
Impairments of goodwill	—	—	(14)	(14)
Other changes	—	1	—	1
Balances as of December 31, 2002	413	62	—	475
Impairments of goodwill	—	(75)	—	(75)
Other changes	—	13	—	13
Balances as of December 31, 2003	$413	$ —	$ —	$413

In 2003, our Production segment impaired $75 million of goodwill which resulted from its decision to reduce its involvement in its Canadian production operations. In 2002, we impaired $14 million of goodwill associated with our Field Services segment, which resulted from the sale of assets in this segment during 2002 and early 2003.

Our other intangible assets consist of customer lists and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life. The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of December 31:

	2003	2002
	(In millions)	
Intangible assets subject to amortization	$ 31	$ 31
Accumulated amortization	(23)	(12)
	$ 8	$ 19

Amortization expense of our intangible assets subject to amortization was $1 million and $7 million for the years ended December 31, 2003 and 2002. For the year ended December 31, 2001, amortization of all intangible assets, including goodwill, was $32 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense is approximately $1 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 loss before extraordinary items and the cumulative effect of accounting changes and net loss for the year ended December 31, 2001, as if goodwill had not been amortized during that year compared to results as actually reported:

	December 31,	
	2001 Restated	2001 Pro forma (Restated)
	(In millions)	
Loss before extraordinary items and cumulative effect of accounting changes	$(578)	$(578)
Amortization of goodwill	—	16
Adjusted loss before extraordinary items and cumulative effect of accounting changes	$(578)	$(562)
Net loss	$(589)	$(589)
Amortization of goodwill	—	16
Adjusted net loss	$(589)	$(573)

Pension and Other Postretirement Benefits

El Paso maintains 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 related to these plans 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 record an additional 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. We also derive revenue from sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity over the contract period regardless of the amount that is actually used. For interruptible or volumetric based services, and for revenues under natural gas sales contracts 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 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 be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We establish reserves for these potential refunds.

Production revenues. Our Production segment derives revenues primarily 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 our production are included in cost of sales.

Field Services revenues. Our Field Services segment derives revenues principally from processing and gathering 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. Our Merchant Energy segment derives revenues from a number of sources including physical sales of power and the management of its derivative contracts. Our derivative transactions are recorded at their fair value, and changes in their fair value are reflected in operating revenues. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities.* Revenues on physical sales are recognized at the time the commodity is delivered and are based on the volumes delivered and the contracted or market price.

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 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

Our price risk management activities primarily consist of derivatives entered into to hedge the commodity price risks on our natural gas and oil production and derivatives related to our power contract restructuring business.

We account for all derivative instruments under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Under SFAS No. 133, derivatives are reflected in our balance sheet at their fair value as assets and liabilities from price risk management activities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. On January 1, 2001, we adopted SFAS No. 133 and recorded a cumulative effect adjustment of $459 million, net of income taxes, in accumulated other comprehensive income (loss) to recognize the fair value of all derivatives designated as hedging instruments on that date. The majority of the initial cumulative-effect adjustment related to cash flow hedges on anticipated sales of natural gas. During the year ended December 31, 2001, $456 million, net of income taxes, of this initial adjustment was reclassified to earnings as a result of completed sales and purchases during that year. See Note 13 for a further discussion of our price risk management activities.

Our income statement treatment of changes in fair value and settlements of derivatives depends on the nature of the derivative instrument. Derivatives used in our hedging activities are reflected as either revenues or expenses in our income statements based on the nature and timing of the hedged transaction. Derivatives related to our power contract restructuring activities are reflected as either revenues (for settlements and changes in the fair values of the power sales contracts) or expenses (for settlements and changes in the fair values of the fuel supply agreements). Prior to 2003, we also had derivative contracts related to our historical trading activities. These activities are reported in revenue on a net basis (revenues net of the expenses of the physically settled purchases). This net presentation began on July 1, 2002 with our adoption of EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involving Energy Trading and Risk Management Activities,* and all periods reflect this presentation. Prior to its adoption, we reflected these activities on a gross basis (physically settled revenues separate from physically settled expenses). Upon its adoption, revenues and costs for the year ended December 31, 2001 were revised as follows (in millions):

Gross operating revenues	$ 5,006
Costs reclassified	(1,042)
Net operating revenues reported in the income statement	$ 3,964

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables and payables in our balance sheet.

During 2002, we also adopted Derivatives Implementation Group (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 our proportionate share of this gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement.

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 or 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.

El Paso maintains a tax accrual policy to record both regular and alternative minimum tax for companies included in its consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, 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 returns. El Paso pays all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso may bill or refund its 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. These gains and losses were insignificant in 2003, 2002 and 2001. 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 in other expense. The net foreign currency loss recorded in other expense was insignificant in 2003, 2002 and 2001. 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 accumulated other comprehensive income (loss) in stockholders' equity. The cumulative currency translation gain (loss) recorded in accumulated other comprehensive income (loss) was $63 million and $(49) million at December 31, 2003 and 2002. Revenues and expenses are translated at average exchange rates prevailing during the year.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, which requires that we record a liability for retirement and removal costs of long-lived assets used in our business. This liability is recorded at its estimated fair value, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $12 million, net of income taxes, related to our adoption of SFAS No. 143. We also recorded property, plant and equipment of $125 million and asset retirement obligations of $143 million as of January 1, 2003. These amounts have been restated to reflect the impact of our reserve revisions on the timing of the settlement of our asset retirement obligations as described in Note 1. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times, generally over the next ten years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells. The net asset retirement liability as of January 1, 2003 and December 31, 2003, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the year ended December 31, 2003, were as follows (in millions):

Net asset retirement liability at January 1, 2003	$143
Liabilities settled in 2003	(33)
Accretion expense in 2003	16
Liabilities incurred in 2003	7
Changes in estimate	8
Net asset retirement liability at December 31, 2003	$141

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2001, our aggregate current and non-current retirement liabilities on that date would have been approximately $130 million and our income from continuing operations and net income for the years ended December 31, 2002 and 2001, would have been lower by $8 million in each year.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. On July 1, 2003, we adopted the provisions of SFAS No. 150, and reclassified $300 million of our Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement. For the year ended December 31, 2003, total dividends were $26 million, of which $13 million were recorded in interest expense and $13 million were recorded as distributions on preferred interests in our income statement.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2003, there were several accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of a significant standard that will impact us.

Consolidation of Variable Interest Entities. In January 2003, the FASB issued Financial Interpretation (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 a company to 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. In December 2003, the FASB issued FIN No. 46-R, which amended FIN No. 46 to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities. In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures or other entities that meet the characteristics of businesses.

On January 1, 2004, we adopted this standard. Upon adoption, we consolidated Blue Lake Gas Storage Company, an equity investment that owns the Blue Lake natural gas storage facility. The impact of this consolidation was a net increase to property, plant and equipment of $72 million, an increase to other current and non-current assets of $6 million, an increase to third-party debt of $14 million, an increase to other liabilities and equity of $15 million, a decrease in our investment balance of $30 million, and a decrease to notes receivable from affiliates of $19 million.

3. Divestitures

During 2002, 2003 and 2004, we completed or announced the sale of a number of assets and investments in each of our business segments as follows:

Segment	Proceeds[1] (In millions)	Significant Assets and Investments
Announced to date or completed in 2004		
Production	$ 410	• Natural gas and oil properties in Canada[3] • International exploration and production assets[3]
Merchant Energy	92	• Utility Contract Funding (UCF)[2] • Mohawk River Funding IV[3][4] • Equity interest in the Bastrop Company power investment[3] • Fulton power facility[3]
Total continuing	502	
Discontinued	905	• Aruba and Eagle Point refineries and other petroleum assets[3]
Total	$1,407	

(1) Amounts on sales that have been announced or are under contract for sale are estimates, subject to customary regulatory approvals, final sale negotiations and other conditions.

(2) We sold our ownership interest in UCF in 2004 for $18 million in cash to an affiliate of Bear Stearns, which also assumed $815 million of UCF debt. We incurred a loss of approximately $90 million on this sale in 2004.

(3) These sales were completed in 2004.

(4) We sold our ownership interest in Mohawk River Funding IV for $3 million in cash to an affiliate of Bear Stearns, which also assumed $72 million of Mohawk River IV debt.

Segment	Proceeds (In millions)	Significant Assets and Investments
Completed in 2003		
Pipelines	$ 89	• Equity interest in Alliance Pipeline System and related assets • Horsham pipeline in Australia • Panhandle gathering system located in Texas
Production	193	• Natural gas and oil properties located in western Canada, New Mexico and the Gulf of Mexico • Drilling rigs
Field Services	94	• Gathering systems located in Wyoming • Midstream assets in the Mid-Continent region
Merchant Energy	11	• Power contracts
Corporate and Other	17	• Aircraft
Total continuing[1]	404	
Discontinued[2]	747	• Corpus Christi refinery, Florida petroleum terminals and other coal and petroleum assets
Total	$1,151	

(1) Includes $20 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with the assets sold.

(2) Includes $84 million of proceeds related to the sale of our asphalt facilities, which includes $39 million of cash, $27 million of accounts and notes receivable, and the release of $18 million of previously outstanding liabilities. In December 2003, we recorded a valuation allowance of $17 million on these receivables, reducing them to their net realizable value. We continue to evaluate the financial condition of the purchaser in order to determine whether an additional valuation allowance on the receivables is necessary.

Segment	Proceeds (In millions)	Significant Assets and Investments
Completed in 2002		
Pipelines	$ 303	• 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
Production	1,297	• Natural gas and oil properties located in Texas, Colorado, Utah and western Canada
Field Services	120	• Dragon Trail gas processing plant • Gathering facilities located in Utah
Total continuing[1]	1,720	
Discontinued	128	• Coal reserves and properties and petroleum assets
Total	$1,848	

(1) Includes $35 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with assets sold.

During the years ended December 31, 2003, 2002 and 2001, our asset impairments and net realized (gains) losses on long-lived assets were $97 million, $(7) million and $69 million and our impairments and net realized (gains) losses on sales of investments were $128 million, $47 million and $(10) million. These gains, losses and asset impairments are discussed in Notes 5, 10 and 22.

For the year ended December 31, 2001, we sold 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. Net proceeds from these sales were approximately $184 million, and we recognized extraordinary net gains of approximately $11 million, net of income taxes of approximately $5 million. These gains were treated as extraordinary since they resulted from a Federal Trade Commission (FTC) order in connection with our merger in 2001 with El Paso.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* we classify assets being disposed of that have received appropriate approvals by our management and/or El Paso's Board of Directors as held for sale or, if appropriate, discontinued operations. As of December 31, 2003 and 2002, we had $7 million and $31 million of assets held for sale reflected in other current assets on our balance sheet. Our assets held for sale as of December 31, 2003 related to domestic power assets in our Merchant Energy segment that were approved by El Paso's Board of Directors for sale in 2003. Our assets held for sale at December 31, 2002 related to gathering assets in our Field Services segment which were sold during 2003.

We continue to evaluate assets we may sell or otherwise divest of in the future. As specific assets are identified for divestiture, we will be required to record them at the lower of fair value, less selling costs, or historical cost. This will require us to assess them for possible impairment. These impairment charges, if any, will generally be based on their estimated fair value as determined by market data obtained through the divestiture process or by assessing the probability-weighted cash flows of the asset. For a discussion of impairment charges incurred on our long-lived assets, see Note 5; for impairments on discontinued operations, see Note 10; and for impairments on our investments in unconsolidated affiliates, see Note 22.

4. Merger-Related Costs

We did not incur any merger-related costs during 2003 and 2002. During 2001, we incurred merger-related costs in connection with our merger with El Paso as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other	Total
			(In millions)			
Employee severance, retention and transition costs	$ 76	$ 7	$ 2	$ 2	$480	$567
Business and operational integration costs	86	15	—	—	22	123
Other	30	23	11	15	18	97
	$192	$45	$13	$17	$520	$787

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 our merger with El Paso, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,200 full-time positions through a combination of early retirements and terminations.

As a result of these actions, employee severance, retention, and transition costs for 2001 were approximately $567 million which included $214 million of pension and postretirement benefits which will be paid over the applicable benefit periods of the terminated and retired employees and a charge of $278 million resulting from the issuance of approximately 4 million shares of El Paso common stock on the date of our merger in exchange for the fair value of our employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares. All other costs were expensed and paid as incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments. Total charges in 2001 were $123 million, which primarily included: (i) $15 million of incremental fees under software and seismic license agreements which were recorded in our Production segment, (ii) $108 million of estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas. In addition, asset impairment charges of $13 million were incurred related to the closure of this facility. The lease-related costs were accrued at the time we completed our relocations and closed these offices and will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed and paid as incurred.

Other costs were $97 million, which include payments made in satisfaction of obligations arising from the FTC approval of our merger with El Paso and other miscellaneous charges. These items were expensed in the period in which they were incurred.

5. Loss (Gain) on Long-Lived Assets

Loss (gain) on long-lived assets from continuing operations consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets including goodwill and other intangibles. During each of the three years ended December 31, our loss on long-lived assets were as follows:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Net realized (gain) loss	$(35)	$(43)	$ 4
Asset impairments			
Merchant Energy			
Power assets	28	18	—
Other	—	—	21
Production			
Canadian assets	14	4	—
Australian and Indonesian assets	—	—	16
Goodwill impairment	75	—	—
Other	10	—	—
Pipelines	—	—	22
Field Services	4	14	—
Corporate	1	—	6
Total asset impairments	132	36	65
Loss (gain) on long-lived assets	$ 97	$ (7)	$ 69

Net Realized (Gain) Loss

Our 2003 net realized gain was primarily related to a $19 million gain on the sales of our Mid-Continent midstream assets in our Field Services segment, a $6 million gain on the sale of the Table Rock sulfur extraction facility in our Pipelines segment, a $5 million gain on the sales of non-full cost pool assets in our Production segment and $5 million of gains on the sales of other assets. Our 2002 net gain was primarily related to $35 million of net gains on the sales of our Natural Buttes and Ouray gathering systems and our Dragon Trail gas processing plant in our Field Services segment and $10 million of other miscellaneous asset sales in our Pipelines segment. See Note 3 for a further discussion of these divestitures.

Asset Impairments

Our impairment charges for the years ended December 31, 2003, 2002 and 2001 were recorded primarily based on our intent to dispose of, or reduce our involvement in a number of assets, as part of liquidity enhancement efforts. Our Production charges include the write-down of goodwill in 2003 that occurred based on our decision to reduce our involvement in our Canadian production operations. Our Merchant Energy charges were primarily a result of our planned sale of our power assets.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 10 and 22. For additional discussion on goodwill and other intangibles, see Note 2.

6. Accounting Changes

Changes in Accounting Principle

During the years ended December 31, 2003 and 2002, we recorded the following cumulative effect of accounting changes due to the adoption of new accounting pronouncements (in millions):

	Before-tax	After-tax
2003		
SFAS No. 143 (restated — See Note 1)	$(18)	$(12)
2002		
DIG Issue No. C-16	$ 23	$ 14

For a discussion of each of the accounting principles we adopted during 2003 and 2002, see Note 2.

Changes in Accounting Estimate

During 2001, we incurred approximately $316 million in costs related to changes in accounting estimates, which consist of $232 million in additional environmental remediation liabilities, $47 million in 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 operations. Of the overall pre-tax amount, approximately $182 million of these costs were included in our continuing operation and maintenance costs and $134 million were related to our discontinued petroleum markets and coal businesses included discontinued operations. Our changes in estimates reduced our overall net income by approximately $241 million, of which $150 million was related to continuing operations and $91 million was related to discontinued operations.

The change in our estimated environmental remediation liabilities was due to a number of events including the sale, closure or lease of a number of the businesses and assets in our discontinued petroleum markets operations, and conforming our methods of environmental identification, assessment and remediation strategies and processes to El Paso's historical practices following our merger with El Paso.

7. Ceiling Test Charges

See Note 1 for a discussion of the restatement of our historical reserves and Note 24 for a discussion of our natural gas and oil reserves.

During the years ended December 31, 2003, 2002 and 2001, we incurred ceiling test charges in the following full cost pools:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.	$ 34	$417	$257
Canada	61	91	225
Brazil	5	3	50
Indonesia	—	1	5
Australia and other international countries	9	9	—
Total	$109	$521	$537

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of qualifying cash flow hedges was considered in determining our ceiling test charges, and will be factored into future ceiling test calculations. The charges for our international cost pools would not have materially changed had the impact of our hedges not been included in calculating our ceiling test charges since we do not significantly hedge our international production activities. Had the impact of qualifying cash flow hedges been excluded from our U.S. full cost pool calculations, we would have incurred no ceiling test charges in 2003, and would have incurred charges of $576 million in 2002 and $1,424 million in 2001 compared with the charges we actually recorded.

8. Other Income and Other Expenses

The following are the components of other income and other expenses from continuing operations for each of the three years ended December 31:

	2003	2002	2001
	(In millions)		
Other Income			
Interest income	$ 17	$13	$23
Re-application of SFAS No. 71 (CIG and WIC)	18	—	—
Development, management and administrative services fees on power projects	11	11	12
Favorable resolution of non-operating contingent obligations	8	31	4
Rental income	—	—	22
Other	12	15	20
Total	$ 66	$70	$81
Other Expenses			
Minority interest in consolidated subsidiaries	$(12)	$52	$—
Other	7	18	18
Total	$ (5)	$70	$18

9. Income Taxes

Our pretax income (loss) from continuing operations is composed of the following for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
	(In millions)		
U.S.	$ 240	$363	$(312)
Foreign	(122)	62	(268)
	$ 118	$425	$(580)

The following table reflects the components of income tax expense (benefit) included in income (loss) from continuing operations for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Current			
Federal	$ 68	$(35)	$ 47
State	14	2	(1)
Foreign	—	5	4
	82	(28)	50
Deferred			
Federal	(93)	141	(21)
State	(12)	33	(11)
Foreign	(34)	(37)	(105)
	(139)	137	(137)
Total income tax expense (benefit)	$ (57)	$109	$ (87)

Our income tax expense (benefit), included in income (loss) from continuing operations 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:

	2003	2002 (Restated)	2001 (Restated)
		(In millions except rates)	
Income tax expense (benefit) at the statutory federal rate of 35%	$ 41	$149	$(203)
Increase (decrease)			
State income tax, net of federal income tax effect	1	23	(8)
Foreign (income) loss taxed at different tax rates	34	(66)	(20)
Depreciation, depletion and amortization	—	—	20
Non-taxable stock dividends	(5)	(5)	(4)
Non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities	—	—	106
Abandonments and sales of foreign investments	(105)	—	—
Valuation allowances	(21)	(3)	19
Other	(2)	11	3
Income tax expense (benefit)	$ (57)	$109	$ (87)
Effective tax rate	(48)%	26%	15%

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

	2003	2002 (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 883	$1,277
Investments in unconsolidated affiliates	302	216
Regulatory and other assets	80	108
Total deferred tax liability	1,265	1,601
Deferred tax assets		
Net operating loss and tax credit carryovers:		
U.S. federal	267	217
State	37	9
Environmental liability	59	57
Price risk management activities	55	52
Allocated merger costs	107	112
Other	97	97
Valuation allowance	(1)	(27)
Total deferred tax asset	621	517
Net deferred tax liability	$ 644	$1,084

Included in our deferred tax assets as of December 31, 2003 are amounts related to abandonments and sales of certain of our foreign investments that have occurred in 2003 or 2004.

At December 31, 2003, 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 $370 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 (loss).

Under El Paso's tax accrual policy, we are allocated the tax effects associated with our employee's nonqualified dispositions of employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends. This allocation increased taxes payable by $4 million in 2003 and reduced taxes payable by $2 million in 2002 and $5 million in 2001. These tax effects are included in additional paid-in capital in our balance sheets.

As of December 31, 2003, we had alternative minimum tax credits of $217 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2003.

	Carryover Period				
	2004	2005-2010	2011-2015	2016-2023	Total
U.S. federal net operating loss	$ —	$ —	$ —	$143	$143
State net operating loss	66	235	1	144	446

Usage of our U.S. federal 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.

We record a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2003, we maintained a valuation allowance of $1 million related to foreign deferred tax assets for ceiling test charges. As of December 31, 2002, we maintained valuation allowances of $22 million related to foreign deferred tax assets for ceiling test charges and $5 million related to state net operating loss carryovers. The change in our valuation allowances from December 31, 2002 to December 31, 2003 is primarily related to foreign ceiling test charges and revisions of future revenue estimates. On June 29, 2004, the State of New Jersey enacted legislation that may limit the use of our New Jersey net operating loss carryovers for tax years 2004 and 2005. This enacted legislation may cause us to record an additional valuation allowance in either 2004 or 2005.

10. Discontinued Operations

Petroleum Markets Operations

In June 2003, El Paso's Board of Directors authorized the sale of our petroleum markets operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. The Board's actions were in addition to previous actions approving the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax charges during 2003 totaling $1.5 billion related to impairments of our petroleum markets assets, which included $1.1 billion related to our Aruba refinery and $264 million related to the impairment of our Eagle Point refinery. These impairments were based on a comparison of the carrying value of our petroleum markets assets to their estimated fair value, less selling costs. In the first quarter of 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million and used a portion of the proceeds to repay $370 million of debt associated with these operations. The magnitude of these charges was impacted by a number of factors, including the nature of the assets to be sold, and our established time frame for completing the sales, among other factors. We also recognized $90 million of realized gains primarily on the sale of our Florida terminalling and transportation assets, asphalt facilities and chemical facilities in 2003. During 2003 and 2004, we sold substantially all of our petroleum markets assets.

Coal Mining Operations

In June 2002, El Paso's Board of Directors authorized the sale of our coal mining operations. These operations, consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following this approval, 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. Because this carrying value was higher than our estimated net sales proceeds, we recorded an impairment charge of $185 million during 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 consisted of mining operations, businesses, properties and reserves in Kentucky, West Virginia and Virginia for $59 million which included $35 million in cash and $24 million in notes receivable. We did not record a significant gain or loss on these sales in 2002 and 2003.

Our petroleum markets operations and our coal mining operations are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of the remaining discontinued businesses are classified as current assets and liabilities as of

December 31, 2003. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	Coal Mining	Total
		(In millions)	
Operating Results			
Year Ended December 31, 2003			
Revenues[1]	$ 5,697	$ 27	$ 5,724
Costs and expenses[1]	(5,837)	(13)	(5,850)
Loss on long-lived assets	(1,404)	(9)	(1,413)
Other income (expense)	(4)	1	(3)
Interest and debt expense	(11)	—	(11)
Income (loss) before income taxes	(1,559)	6	(1,553)
Income taxes	(261)	5	(256)
Income (loss) from discontinued operations, net of income taxes	$(1,298)	$ 1	$(1,297)
Year Ended December 31, 2002			
Revenues[1]	$ 4,814	$ 309	$ 5,123
Costs and expenses[1]	(4,954)	(327)	(5,281)
Loss on long-lived assets	(97)	(184)	(281)
Other income	20	5	25
Interest and debt expense	(12)	—	(12)
Loss before income taxes	(229)	(197)	(426)
Income taxes	12	(73)	(61)
Loss from discontinued operations, net of income taxes	$ (241)	$(124)	$ (365)
Year Ended December 31, 2001			
Revenues[1]	$ 4,900	$ 277	$ 5,177
Costs and expenses[1]	(5,016)	(286)	(5,302)
Loss on long-lived assets	(106)	—	(106)
Other income	111	2	113
Interest and debt expense	(27)	—	(27)
Loss before income taxes	(138)	(7)	(145)
Income taxes	(58)	(2)	(60)
Loss from discontinued operations, net of income taxes	$ (80)	$ (5)	$ (85)

[1] These amounts include intercompany activities between our discontinued petroleum markets operations and our continuing operating segments.

	Petroleum Markets	Coal Mining	Total
		(In millions)	
Financial Position Data			
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivables	$ 262	$ —	$ 262
Inventory	385	—	385
Other current assets	131	—	131
Property, plant and equipment, net	521	—	521
Other non-current assets	70	—	70
Total assets of discontinued operations	$1,369	$ —	$1,369
Liabilities of discontinued operations			
Accounts payable	$ 172	$ —	$ 172
Other current liabilities	86	—	86
Long-term debt	374	—	374
Environmental remediation reserve	24	—	24
Other non-current liabilities	2	—	2
Total liabilities of discontinued operations	$ 658	$ —	$ 658
December 31, 2002			
Assets of discontinued operations			
Accounts and notes receivables	$1,229	$ 29	$1,258
Inventory	636	14	650
Other current assets	79	1	80
Property, plant and equipment, net	1,950	46	1,996
Other non-current assets	65	16	81
Total assets of discontinued operations	$3,959	$106	$4,065
Liabilities of discontinued operations			
Accounts payable	$1,153	$ 20	$1,173
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities of discontinued operations	$1,420	$ 40	$1,460

11. Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Long-term financing obligations, including current maturities	$5,321	$5,233	$5,354	$4,637
Company-obligated preferred securities of subsidiaries[(1)]	—	—	300	160
Commodity-based price risk management derivatives	818	818	818	818

(1) These were reclassified as long-term financing obligations upon our adoption of SFAS No. 150 in 2003.

As of December 31, 2003 and 2002, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represent 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 interest rate. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. See Note 12 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

For the years ended December 31, 2003 and 2002, we had one customer that comprised greater than five percent of our net credit exposure from our price risk management activities. This customer, Public Service Electric and Gas Company (PSEG), comprised $812 million and $896 million of the net exposure as of December 31, 2003 and 2002. PSEG was rated as investment grade by Moody's Investor Services and Standard & Poor's, and we have not required any collateral from them as of December 31, 2003 and 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. As a result of our sale of UCF in 2004, this exposure was substantially reduced.

12. Price Risk Management Activities

In the table below, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production as well as instruments to hedge our interest rate risks on long-term debt. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business. The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31:

	2003	2002
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$(124)	$(146)
Derivatives from power contract restructuring activities	942	968
Other commodity-based derivative contracts	—	(4)
Net assets from price risk management activities[1]	$ 818	$ 818

[1] Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. Due to major industry participants exiting or reducing their trading activities in 2002 and 2003, the availability of reliable commodity pricing data from market-based sources that we used in estimating the fair value of our derivatives was significantly limited for certain locations and for longer time periods. Consequently, we now use an independent pricing source for a substantial amount of our forward pricing data beyond the current two-year period. For forward pricing data within two years, we use commodity prices from market-based sources such as the New York Mercantile Exchange. For periods beyond two years, we use a combination of commodity prices from market-based sources and other forecasted settlement prices from an independent pricing source to develop price curves, which we then use to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discount these estimated settlement values using a LIBOR curve, except as described below for our restructured power contracts.

We record valuation adjustments to reflect uncertainties associated with the estimates we use in determining fair value. Common valuation adjustments include those for market liquidity and those for the credit-worthiness of our contractual counterparties. To the extent possible, we use market-based data together with quantitative methods to measure the risks for which we record valuation adjustments and to determine the level of these valuation adjustments.

The above valuation techniques are used for valuing derivative contracts that are used to hedge our natural gas production. We have adjusted this method to determine the fair value of our restructured power contracts. Our restructured power derivatives use the same methodology discussed above for determining the forward settlement prices but are discounted using a risk free interest rate, adjusted for the individual credit spread for each counterparty to the contract. Additionally, no liquidity valuation adjustment is provided on these derivative contracts since they are intended to be held through maturity.

Derivatives Designated as Hedges

We engage in hedges of cash flow exposure primarily related to our natural gas and oil production activities. Hedges of cash flow exposure are designed to hedge forecasted sales transactions or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income to the extent they are effective and are not included in income until the hedged transactions occur and are recognized in earnings. The ineffective portion of the hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement.

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 whether these derivatives 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.

A summary of the impacts of our cash flow hedges included in accumulated other comprehensive income (loss), net of income taxes, as of December 31, 2003 and 2002 follows:

	Accumulated Other Comprehensive Income (Loss)		Estimated Income (Loss) Reclassification in 2004[1]	Final Termination Date
	2003	2002		
Held by consolidated entities	$(49)	$(39)	$ (1)	2005
Held by unconsolidated affiliates	13	16	5	2005
Undesignated[2]	(25)	(55)	(25)	2004
Total cash flow hedges	$(61)	$(78)	$(21)	

(1) Reclassifications occur upon the physical delivery of the hedge commodity and the corresponding expiration of the hedge.

(2) In May 2002, we announced the plan to reduce the volumes of natural gas hedges for our Production segment, and, as a result, we removed the hedging designation on these derivatives.

For the years ended December 31, 2003, 2002 and 2001, we recognized net losses of $1 million, $3 million and $1 million, net of income taxes, in our income from continuing operations related to the ineffective portion of all cash flow hedges.

Power Contract Restructuring Activities

During 2001 and 2002, we conducted power contract restructuring activities that involved amending or terminating power purchase contracts at existing power facilities. In a restructuring transaction, we would eliminate the requirement that the plant provide power from its own generation to the customer of the contract (usually a regulated utility) and replace that requirement with a new contract that gave us the ability to provide power to the customer from the wholesale power market. In conjunction with these power restructuring activities, we generally entered into additional market-based contracts with El Paso Merchant Energy, our affiliate, to provide the power from the wholesale power market, which effectively "locked in" our margin on the restructured transaction as the difference between the contracted rate in the restructured sales contract and the wholesale market rates on the power purchase contract at the time.

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

Following a restructuring, the accounting treatment for the power purchase agreement changed since the restructured contract met the definition of a derivative. In addition, since the power plant no longer had the exclusive obligation to provide power under the original, dedicated power purchase contract, it operated as a peaking merchant facility, generating power only when it was economical to do so. Because of this significant change in its use, the plant's carrying value was typically written down to its estimated fair value. These changes also often required us to terminate or amend any related fuel supply and/or steam agreements, and enter into other third-party and intercompany contracts such as transportation agreements, associated with operating the merchant facility. Finally, in many cases power contract restructuring activities also involved contract terminations that resulted in cash payments by the customer to cancel the underlying dedicated power contract.

In 2002, we completed a power contract restructuring on our consolidated Eagle Point power facility and applied the accounting described above to that transaction. We also employed the principles of our power contract restructuring business in reaching a settlement of a 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[(1)]
Initial gain on restructured contracts	$978	$ 80		$ 988		$ 172
Write-down of power plants and intangibles and other fees			$(328)		$489	(109)
Change in value of restructured contracts during 2002	8			(96)		(20)
Change in value of third-party wholesale power supply contracts		(62)		62		(3)
Purchase of power under power supply contracts					47	(11)
Sale of power under restructured contracts				111		28
Total	$986	$ 18	$(328)	$1,065	$536	$ 57

(1) In our restructuring activities, third-party owners also held ownership interests in the plants and were allocated a portion of the income or loss.

During 2003 no new power restructuring transactions were completed and, as a result, our consolidated financial statements for the year ended December 31, 2003 only reflect the change in value of the above restructured contracts and power supply contracts, and the related purchases and sales under these contracts. As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities. In June 2004, we completed the sale of UCF (which is the restructured Eagle Point power contract).

13. Inventory

We have the following inventory as of December 31:

	2003	2002
	(In millions)	
Materials and supplies and other	$58	$61

14. Regulatory Assets and Liabilities

Our regulatory assets and liabilities are included in other current and non-current assets and liabilities in our balance sheets. These balances are presented in our balance sheets on a gross basis. During 2003, CIG and WIC met the requirements to re-apply the provisions of SFAS No. 71. As a result of applying this standard, we recorded $18 million in regulatory assets and a pre-tax benefit of $18 million in our 2003 income statement. In addition, $2 million of other assets and $10 million of other liabilities were reclassified as regulatory assets/liabilities upon re-application of SFAS No. 71. Below are the details of our regulatory assets and liabilities, which represent our regulated interstate systems that apply the provisions of SFAS No. 71, as of December 31:

Description	2003	Remaining Recovery Period
	(In millions)	(Years)
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction[1]	$12	23-29
Postretirement benefits	6	7
Under-collected federal income taxes[1]	2	N/A
Total regulatory assets[2]	$20	
Current regulatory liabilities		
Postretirement benefits[1]	$ 1	N/A
Non-current regulatory liabilities		
Excess deferred federal income taxes	4	7
Over-collected fuel obligation	5	N/A
Total non-current regulatory liabilities	9	
Total regulatory liabilities[2]	$10	

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

(2) Amounts are included as other non-current assets and other current and non-current liabilities in our balance sheets.

15. Property, Plant and Equipment

At December 31, 2003 and 2002, we had approximately $373 million and $666 million of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2003 and 2002, ANR has excess purchase costs associated with its acquisition. Total excess costs on this pipeline were approximately $2 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during each of the three years ended December 31, 2003, 2002 and 2001 was approximately $34 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 do not earn a return on these excess purchase costs from our rate payers.

16. Debt, Other Financing Obligations and Other Credit Facilities

Our long-term financing obligations outstanding consisted of the following as of December 31:

	2003	2002
	(In millions)	
Long-term debt		
El Paso CGP		
Senior notes, 6.2% through 8.125%, due 2004 through 2010	$1,305	$1,305
Floating rate senior notes, due 2003	—	200
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,395	1,497
Valero lease financing loan due 2004[1]	—	240
Power		
Non-recourse senior notes, 7.75% and 7.944%, due 2008 and 2016	904	915
Recourse notes 8.5%, due 2005	81	126
El Paso Production Company		
Floating rate notes, due 2005 and 2006	200	200
ANR Pipeline		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	800	500
Notes, 13.75% due 2010	13	13
Colorado Interstate Gas		
Debentures, 6.85% and 10.0%, due 2005 and 2037	280	280
Other	51	84
Subtotal	5,029	5,360
Other financing obligations		
Coastal Finance I	300	—
	5,329	5,360
Less:		
Unamortized discount on long-term debt	8	6
Current maturities of long term debt and other financing obligations	310	369
Total long-term financing obligations, less current maturities	$5,011	$4,985

[1] The Valero lease financing loan, a general corporate obligator, was collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery. This loan was repaid in February 2003.

During 2003 and to date in 2004, we had the following changes in our debt financing obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]/ Retirements	Due Date
				(In millions)		
Issuance						
March	ANR	Senior notes	8.875%	$ 300	$ 288	2010
Retirements						
January-December	El Paso CGP	Long-term debt	Various	$ 103	$ 103	
February	El Paso CGP	Long-term debt	4.49%	240	240	
July	El Paso CGP	Note	Floating rate	200	200	
August	El Paso CGP	Senior debentures	9.75%	102	102	
	Retirements through December 31, 2003			645	645	
March 2004	El Paso Production Company	Note	LIBOR + 3.5%	200	200	
May 2004	El Paso CGP	Note	6.20%	190	190	
January-September 2004	El Paso CGP	Long-term debt	Various	77	77	
				$1,112	$1,112	
Other Changes in Debt						
July 2003	Coastal Finance I[2]	Preferred securities	8.375%	$ 300	$ 300	2038
	Other Changes through December 31, 2003			300	300	
January 2004	Blue Lake Gas Storage	Term loan	LIBOR + 1.2%	14	14	2006
March 2004	Mohawk River Funding IV[3]	Note	7.75%	(72)	(72)	2008
June 2004	Utility Contract Funding[3]	Non-recourse senior notes	7.944%	(815)	(815)	2016
				(573)	(573)	

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for other general corporate and investment purposes.

(2) During the third quarter of 2003, these preferred securities were reclassified as long-term debt as a result of adopting SFAS No. 150.

(3) Non-recourse debt reduced as a result of the sale of our interests in Mohawk River Funding IV and UCF in 2004.

Aggregate maturities of the principal amounts of long-term financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2004	$ 310
2005	363
2006	654
2007	58
2008	476
Thereafter	3,468
Total long-term financing obligations, including current maturities	$5,329

Included in the "thereafter" line of the table above are $375 million of debentures that holders have an option to redeem prior to their stated maturity. Of this amount, $75 million can be redeemed in 2005 and $300 million can be redeemed in 2007.

Coastal Finance I. Coastal Finance I is a 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 us 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. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. We provide 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. During the third quarter of 2003, these preferred securities were reclassified as long-term debt on our balance sheet as a result of adopting SFAS No. 150 (see Notes 2 and 17). We began classifying dividends accrued on these preferred securities as interest and debt expense in our financial statements after July 1, 2003.

Credit Facilities

In April 2003, El Paso entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. This $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on unused amounts of the facility. This $3 billion revolving credit facility replaced El Paso's previous $3 billion revolving credit facility. We are not a party to the $3 billion revolving credit facility, although our subsidiaries, ANR and CIG, are borrowers under the facility. As of December 31, 2003, there were $850 million of borrowings outstanding and $1.2 billion of letters of credit issued under the $3 billion revolving credit facility, none of which was borrowed or issued on our behalf. Through September 30, 2004, El Paso had repaid $850 million of the debt outstanding under the $3 billion revolving credit facility. As of October 8, 2004, El Paso's borrowing availability under this facility was $1.4 billion.

Prior to December 2003, the $3 billion revolving credit facility and other financing arrangements were also partially collateralized by various natural gas and oil properties and production payments of El Paso and its subsidiaries. Upon repayment of the Clydesdale financing arrangement in December 2003, the production payment and these natural gas and oil properties were released from the collateral package. Our equity interest in CIG became part of the collateral package supporting the $3 billion revolving credit facility and the other financing arrangements and CIG became a borrower under the facility. The $3 billion revolving credit facility and approximately $300 million of El Paso's other financing arrangements are collateralized by our equity in ANR, CIG, WIC and ANR Storage Company, along with other assets of El Paso.

In April 2003, El Paso removed us as a borrower under its $1 billion 3-year revolving credit and competitive advance facility, and as such, we were no longer jointly and severally liable for any amounts outstanding under that facility, which expired on August 4, 2003.

Restrictive Covenants

We have entered into debt instruments and guaranty agreements that contain covenants such as limitations on debt levels, limitations on liens securing debt and guarantees, limitations on mergers and on sales of assets, capitalization requirements and dividend limitations. A breach of any of these covenants could potentially accelerate our debt and other financial obligations and that of our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $850 million.

Various other financing arrangements entered into by us and our subsidiaries include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indentures. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The filing of our our first and second quarter 2004 Forms 10-Q will cure the non-compliance caused by our failure to file financial statements. In addition, we have not received notice of the default caused by our failure to file financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

In addition, our indentures associated with our public debt contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of us or our significant subsidiaries (as defined in the agreements) in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our's and El Paso's debt would adversely affect our liquidity position and in turn, our financial condition.

In 2004, El Paso was required to obtain waivers on its $3 billion revolving credit facility and other financing transactions (see Note 1) to address issues related to its reserve revisions as further discussed in Note 1. These waivers were subsequently extended and continue to be effective. In connection with these waivers, El Paso received an extension until November 30, 2004 to file its first and second quarter 2004 Forms 10-Q.

17. 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 were as follows (in millions):

	2003	2002
Coastal Securities Company Limited Preferred Stock	$ —	$100
Coastal Finance I	—	300
	$ —	$400

Coastal Securities Company Limited 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, to generate funds for investment and general operating purposes. In December 2003, we redeemed the entire $100 million of the outstanding preferred interests and paid the accrued and unpaid dividends.

Additionally, during 2003 the outstanding amount of the preferred interest in Coastal Finance I was reclassified as a long-term financing obligation with the adoption of SFAS No. 150 (see Note 16).

18. Commitments and Contingencies

Legal Proceedings

Grynberg. A number of our subsidiaries were named defendants in actions filed in 1997 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 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). 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 are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.*, filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they 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, attorneys' 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 of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied on April 10, 2003. Plaintiffs' were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action has since been filed as to the heating content claims. Our costs and legal exposure related to these lawsuits and claims 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 have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and our subsidiaries are currently one of several defendants in over 50 such lawsuits nationwide, which have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs generally seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Reserves. We have been named as a defendant in a purported class action claim styled, *GlickenHaus & Co. et. al. v. El Paso Corporation, El Paso CGP Company, et. al.*, filed in April 2004 in federal court in Houston. The plaintiffs have additionally sued several individuals. The plaintiffs generally allege that our reporting of oil and gas reserves was materially false and misleading between February 2000 and February 2004. This lawsuit has been consolidated with other purported securities class action lawsuits in *Oscar S. Wyatt et. al. v. El Paso Corporation et. al.* pending in federal court in Houston. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Governmental Investigations

Governmental and Other Reviews. In October 2003, El Paso announced that the SEC had authorized the Staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We are cooperating with the SEC investigation.

Reserve Revisions. In March 2004, El Paso received a subpoena from the SEC requesting documents relating to El Paso's previously announced reserve revision. El Paso and El Paso's Audit Committee have also received federal grand jury subpoenas for documents regarding the reserve revision. We are assisting El Paso and the Audit Committee in their efforts to cooperate with the SEC and the U.S. Attorney investigations into the matter.

CFTC Investigation. In April 2004, our affiliates elected to voluntarily cooperate with the Commodity Futures Trading Commission (CFTC) in connection with the CFTC's industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, our affiliates provided information relating to storage reports provided to the Energy Information Administration for the period of October 2003 through December 2003. On August 30, 2004, the CFTC announced they had completed the investigation and found no evidence of wrongdoing.

Iraq Oil Sales. In September 2004, we received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nation's Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records relating to transactions in oil of Iraqi origin during the period from 1995 to 2003. Others in the energy industry have received similar subpoenas.

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 this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate. As of December 31, 2003, we had approximately $27 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, 2003, we had accrued approximately $131 million, including approximately $129 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies and approximately $2 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $131 million, $114 million was reserved for facilities we currently operate, and $17 million was reserved for non-operating sites (facilities that are shut down or have been sold) including superfund sites.

Our reserve estimates range from approximately $131 million to approximately $252 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($49 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($82 million to $203 million) and the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	December 31, 2003	
Sites	Low	High
	(In millions)	
Operating	$114	$180
Non-operating	12	64
Superfund	5	8

Below is a reconciliation of our accrued liability as of December 31, 2003 (in millions):

Balance as of January 1, 2003	$ 62
Additions/adjustments for remediation activities	12
Payments for remediation activities	(10)
Other charges, net	67
Balance as of December 31, 2003	$131

For 2004, we estimate that our total remediation expenditures will be approximately $26 million. In addition, we expect to make capital expenditures for environmental matters of approximately $29 million in the aggregate for the years 2004 through 2008. These expenditures primarily relate to compliance with clean air regulations.

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 26 active sites under the 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, 2003, we have estimated our share of the remediation costs at these sites to be between $5 million and $8 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. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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.

There are other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

While the outcome of our outstanding rate and regulatory matters cannot be predicted with certainty. We believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure and accruals related to these matters.

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 2004 until 2031. As of December 31, 2003, our total commitments under operating leases were approximately $156 million. Minimum annual rental commitments under our operating leases at December 31, 2003, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2004	$ 21
2005	20
2006	21
2007	18
2008	17
Thereafter	59
Total	$156

Rental expense on our operating leases for the years ended December 31, 2003, 2002 and 2001 was $27 million, $86 million and $39 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. As of December 31, 2003, we had approximately $43 million of both financial and performance guarantees, including $23 million of guarantees related to our petroleum markets discontinued operations, not otherwise reflected in our financial statements. The remaining guarantees are related to our domestic and international power operations.

Other Commercial Commitments

We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2003, we had firm commitments under transportation and storage capacity contracts of $331 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $193 million. Included in other purchase and capital commitments are unconditional purchase obligations entered into by our pipelines for products and services totaling $212 million at December 31, 2003. Our annual obligations under these agreements are $23 million for each of the years 2004 through 2008, and $97 million in total thereafter.

19. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan that covers substantially all of its U.S. employees, including our employees except for employees of our coal and former retail operations who are covered under separate plans.

Prior to our merger with El Paso, we maintained defined benefit plans. Our pension plans covered substantially all of our U.S. employees. On April 1, 2001, our primary pension plan was merged into El Paso's existing cash balance plan. Our employees who were participants in our primary plan on March 31, 2001 receive the greater of cash balance benefits or our plan benefits accrued through March 31, 2006.

We continue to maintain two other pension plans (Coastal Mart and Coastal Coal) that are closed to new participants and provide benefits to former employees of our previously discontinued coal and convenience store operations. El Paso does not anticipate making any contributions to these pension plans in 2004.

In 2001, El Paso offered an early retirement incentive program associated with El Paso's pension plans for eligible employees of Coastal. This program offered enhanced pension benefits to individuals who elected early retirement. Net charges incurred in connection with this program were approximately $137 million in 2001. During 2003, there were $1 million in charges, that resulted from employee terminations and our internal reorganization.

El Paso also maintains a defined contribution plan covering its U.S. employees, including our employees. We maintained a defined contribution plan which was merged into El Paso's defined contribution plan on January 29, 2001. Prior to May 1, 2002, El Paso 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, El Paso suspended the matching contribution, but reinstituted it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, El Paso increased the matching contribution to 75 percent of participant basic contributions up to 6 percent. As a result of El Paso not being current on its SEC filings, the Plan Committee temporarily suspended participants from making future contributions to or transferring other investment funds to the El Paso Corporation Stock Fund effective June 25, 2004. This temporary suspension does not affect the participant's ability to maintain or transfer the investment that they may currently have in the El Paso Corporation Stock Fund. Participants may continue to sell stock currently held in the El Paso Corporation Stock Fund at their discretion (subject to any insider trading restrictions). As soon as El Paso completes its required SEC filings and is in compliance with the SEC requirements, participants will be able to invest in the El Paso Corporation Stock Fund again. El Paso is responsible for benefits accrued under its plans and allocates the related costs to its affiliates.

Other Postretirement Benefits

In 2001, El Paso offered a one-time election to continue benefits in our postretirement medical and life plans through an early retirement incentive program for eligible employees of Coastal. Net charges incurred with this program were approximately $65 million. El Paso reserves the right to change these benefits.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. Benefit obligations and costs reported that are related to prescription drug coverage do not reflect the impact of this legislation. Current accounting standards that are effective in 2004 may require changes to previously reported benefit information.

In January 2001, following the merger, we changed the measurement date for measuring our pension and other postretirement benefit obligations from December 31 to September 30. We made this change to conform our measurement date to the date El Paso uses to measure pension and other postretirement benefit obligations. The new method is consistent with the manner in which El Paso gathers pension and other postretirement benefit information and will facilitate ease of planning and reporting in a more timely manner. We believe this method is preferable to the method previously employed. We accounted for this as a change in accounting principle, and it had no material effect on retirement benefit expense for the current or prior periods.

Due to a corporate-wide restructuring during 2002, we no longer own Coastal Mart, Inc. As a result, the 2002 and 2003 pension benefits shown below only reflect benefits under our Coastal Coal, Inc. plans. Below is the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our pension and other postretirement benefit plans. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$ 79	$ 84	$102	$109
Service cost	2	3	—	1
Interest cost	4	5	6	8
Participant contributions	—	—	5	4
Curtailment and special termination benefit	(8)	—	(6)	—
Actuarial loss (gain)	7	10	10	(4)
Projected benefits paid	(3)	(3)	(17)	(16)
Transfer of plan obligations	—	(20)	—	—
Projected benefit obligation at end of period	$ 81	$ 79	$100	$102
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 59	$ 97	$ 46	$ 40
Actual return (loss) on plan assets	7	(8)	8	(1)
Employer contributions	—	—	17	18
Participant contributions	—	—	5	4
Projected benefits paid	(3)	(3)	(17)	(15)
Transfer of plan assets	—	(27)	—	—
Fair value of plan assets at end of period	$ 63	$ 59	$ 59	46
Reconciliation of funded status:				
Fair value of plan assets at September 30	$ 63	$ 59	$ 59	$ 46
Less: Projected benefit obligation at end of period	81	79	100	102
Funded status at September 30	(18)	(20)	(41)	(56)
Fourth quarter contributions and income	—	—	4	4
Unrecognized net actuarial loss (gain)	25	28	(24)	(29)
Unrecognized prior service cost	—	1	—	—
Prepaid (accrued) benefit cost at December 31,	$ 7	$ 9	$(61)	$(81)

	Pension Benefits 2003	Pension Benefits 2002
	(In millions)	
Amounts recognized in the statement of financial position consist of:		
Prepaid benefit cost	$ —	$ —
Accrued benefit liability	(18)	(11)
Intangible asset	—	1
Accumulated other comprehensive loss	25	19
Net amount recognized at year-end	$ 7	$ 9
Other comprehensive loss attributable to change in additional minimum liability recognition	$ 6	$ 19

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

	2003	2002
	(In millions)	
Projected benefit obligation	$81	$79
Accumulated benefit obligation	81	70
Fair value of plan assets	63	59

The portion of our other postretirement benefits obligation included in current liabilities was $3 million as of December 31, 2003 and 2002. For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Year Ended December 31,					
	2003	2002	2001	2003	2002	2001
	(In millions)					
Service cost	$ 2	$ 3	$ 5	$—	$ 1	$ 1
Interest cost	5	5	20	6	8	9
Expected return on plan assets	(6)	(7)	(55)	(2)	(2)	(2)
Amortization of net actuarial gain (loss)	—	—	(9)	(1)	(1)	—
Amortization of transition obligation	—	—	(2)	—	—	—
Curtailment and special termination benefits	1	—	137	(6)	—	65
Net benefit cost (income)	$ 2	$ 1	$ 96	$(3)	$ 6	$73

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded an other comprehensive loss of $6 million in 2003 and $19 million in 2002 related to the change in this additional minimum liability.

Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit cost of our pension and other postretirement plans for 2003, 2002 and 2001:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	6.00	6.75		6.00	6.75	
Rate of compensation increase		4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.75	7.25	7.75	6.75	7.25	7.75
Expected return on plan assets(1)	8.80	8.80	10.00	7.50	7.50	7.50
Rate of compensation increase	4.00	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate of 38 percent on postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio. For 2004, the assumed expected return on assets for pension benefits will be reduced to 8.50%.

Actuarial estimates for our other postretirement benefits plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2003, 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 as of September 30:

	2003	2002
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	3	2
One percentage point decrease:		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	(3)	(2)

Plan Assets

The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

	Pension Plans			Other Postretirement Plans		
Asset Category	Target	Actual 2003	Actual 2002	Target	Actual 2003	Actual 2002
		(Percent)			(Percent)	
Equity securities(1)	70	70	66	65	28	—
Debt securities	30	29	33	35	58	—
Other	—	1	1	—	14	100
Total	100	100	100	100	100	100

(1) Actuals for our pension plans include $1 million (2.1 percent of total assets) and $2 million (2.6 percent of total assets) of El Paso's common stock at September 30, 2003 and September 30, 2002.

The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

In late 2003, we modified our target asset allocations for our other postretirement plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2003 had not yet been adjusted to reflect this allocation change. For 2004, we modified our target and actual asset allocations for our pension plans to reduce our equity allocation to 60 percent of total plan assets. Correspondingly, our 2004 assumption related to the expected return on plan assets will be reduced from 8.80% to 8.50% to reflect this change.

20. Segment Information

We segregate our business activities into four 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. Our Production segment information for the years ended December 31, 2002 and 2001 has been restated as further discussed in Note 1. In 2002 and 2003, we reclassified our petroleum markets and coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's operating results for all periods reflect this change.

Our Pipelines segment provides natural gas transmission, storage and related services, in the U.S. We conduct our activities primarily through three wholly owned and a partially owned interstate transmission systems along with four underground natural gas storage entities.

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 10 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 and Indonesia.

Our Field Services segment provides customers with processing and gathering services. Field Services' assets are primarily located in the south Louisiana region.

Our Merchant Energy segment owns and has interests in domestic and international power. We own or have interests in 19 power plants in 8 countries.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2003, 2002 and 2001.

We use EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Total EBIT	$ 579	$ 890	$ (63)
Interest and debt expense	(403)	(421)	(420)
Affiliated interest expense, net	(41)	(9)	(46)
Distributions on preferred interests of consolidated subsidiaries	(17)	(35)	(51)
Income taxes	57	(109)	87
Income (loss) from continuing operations	$ 175	$ 316	$(493)

The following tables reflect our segment results as of and for each of the three years ended December 31:

	Regulated	Unregulated				
	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other[(1)]	Total
	Segments As of or for the Year Ended December 31, 2003 (In millions)					
Revenues from external customers						
Domestic	$ 915	$ 742[(2)]	$328	$ 168	$ —	$ 2,153
Foreign	2	56	2	77	—	137
Intersegment revenue	1	112	26	(7)	(48)	84[(3)]
Operation and maintenance	246	176	20	105	(7)	540
Depreciation, depletion and amortization	108	377	7	15	10	517
Ceiling test charges	—	109	—	—	—	109
Loss (gain) on long-lived assets	(11)	93	(13)	28	—	97
Operating income (loss)	$ 397	$ 80	$ 41	$ 7	$ (5)	$ 520
Earnings (losses) from unconsolidated affiliates	75	10	(93)	(6)	2	(12)
Other income	32	2	—	13	19	66
Other expense	(4)	—	—	10	(1)	5
EBIT	$ 500	$ 92	$(52)	$ 24	$ 15	$ 579
Assets of continuing operations[(4)]						
Domestic	5,271	1,950	224	1,556	668	9,669
Foreign	—	671	—	601	99	1,371
Capital expenditures and investments in unconsolidated affiliates, net[(5)]	192	728	14	(9)	(12)	913
Total investments in unconsolidated affiliates	397	52	54	804	5	1,312

(1) Includes our Corporate and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue and operation and maintenance expense elimination, which is included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $1.4 billion (see Note 10).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

	Regulated	Unregulated				
	Pipelines	Production (Restated)	Field Services	Merchant Energy	Corporate and Other[1]	Total (Restated)
	Segments As of or for the Year Ended December 31, 2002 (In millions)					
Revenues from external customers						
Domestic	$ 901	$1,092[2]	$ 404	$1,072	$ —	$ 3,469
Foreign	3	71	3	154	—	231
Intersegment revenue	30	95	53	(22)	(30)	126[3]
Operation and maintenance expenses	235	243	45	239	15	777
Depreciation, depletion and amortization	116	468	14	19	13	630
Ceiling test charges	—	521	—	—	—	521
Loss (gain) on long-lived assets	(12)	6	(21)	18	2	(7)
Operating income (loss)	$ 419	$ (57)	$ 68	$ 385	$ (38)	$ 777
Earnings (losses) from unconsolidated affiliates	105	4	(53)	57	—	113
Other income	16	1	—	25	28	70
Other expense	(3)	—	—	(58)	(9)	(70)
EBIT	$ 537	$ (52)	$ 15	$ 409	$ (19)	$ 890
Assets of continuing operations[4]						
Domestic	5,128	2,203	451	1,748	528	10,058
Foreign	47	578	14	636	157	1,432
Capital expenditures and investments in unconsolidated affiliates, net[5]	252	1,124	20	(26)	405	1,775
Total investments in unconsolidated affiliates	404	90	143	851	17	1,505

(1) Includes our Corporate and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue and operation and maintenance expense elimination, which is included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $4.1 billion (see Note 10).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

	Regulated	Unregulated				
	Pipelines	Production (Restated)	Field Services	Merchant Energy	Corporate and Other[(1)]	Total (Restated)
			(In millions)			
Segments As of or for the Year Ended December 31, 2001						
Revenues from external customers						
Domestic	$ 982	$1,772[(2)]	$822	$ 43	$ 355	$ 3,974
Foreign	2	46	4	—	—	52
Intersegment revenue	70	(35)	68	—	(165)	(62)[(3)]
Operation and maintenance	278	241	66	36	198	819
Merger-related costs	192	45	13	17	520	787
Depreciation, depletion and amortization	137	658	15	5	21	836
Ceiling test charges	—	537	—	—	—	537
Loss on long-lived assets	22	16	—	21	10	69
Operating income (loss)	$ 195	$ 158	$ 56	$ (41)	$ (714)	$ (346)
Earnings from unconsolidated affiliates	98	4	14	104	—	220
Other income	8	3	2	47	21	81
Other expense	(9)	(2)	—	(2)	(5)	(18)
EBIT	$ 292	$ 163	$ 72	$ 108	$ (698)	$ (63)
Assets of continuing operations[(4)]						
Domestic	5,347	3,725	584	395	444	10,495
Foreign	14	529	17	894	32	1,486
Capital expenditures and investments in unconsolidated affiliates, net[(5)]	421	1,814	53	(12)	290	2,566
Total investments in unconsolidated affiliates	547	86	217	931	17	1,798

(1) Includes our Corporate and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue and operation and maintenance elimination, which is included in the "Corporate and Other" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $4.8 billion.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

21. Supplemental Cash Flow Information

The following table contains supplemental cash flow information from continuing operations for each of the three years ended December 31 for interest and taxes, which were reflected in the asset and liability changes in our statements of cash flows:

	2003	2002	2001
		(In millions)	
Interest paid, net of amounts capitalized	$586	$502	$565
Income tax payments (refunds)	92	(23)	82

22. Investments in and Advances to Unconsolidated Affiliates and Transactions with Related Parties

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are interstate pipelines and power generation plants. Our investment balance was less than our equity in the net assets of these investments as of December 31, 2003 by $37 million, and greater than our equity in the net assets of these investments in 2002 by $46 million. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

	Country	Type of Entities	Net Ownership Interest	Investments 2003	Investments 2002 (Restated)	Advances 2003	Advances 2002
			(Percent)	(In millions)			
Domestic:							
Bastrop Company[1]		LLC[2]	50	$ 73	$ 121	$ —	$ —
Great Lakes Gas Transmission[3]		LP[5]	50	325	312	—	—
Midland Cogeneration Venture[4]		LP[5]	44	348	316	—	—
Noric Holdings I		LLC[2]	38	52	90	—	—
Other Domestic Investments			various	130	253	22	21
Total domestic				928	1,092	22	21
Foreign:							
EGE Fortuna	Panama	Corporation	25	59	61	—	—
EGE Itabo	Dominican Republic	Corporation	25	87	87	—	—
Habibullah Power	Pakistan	LLC[2]	50	48	57	90	99
Saba Power Company	Pakistan	LLC[2]	94	59	55	—	—
Other Foreign Investments			various	131	153	13	50
Total foreign				384	413	103	149
Total investments in and advances to unconsolidated affiliates				$1,312	$1,505	$125	$170

(1) In June 2004, we completed the sale of our interest in this investment.

(2) LLC represents Limited Liability Company.

(3) 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.

(4) Our ownership interest consists of a 38.1 percent general partner interest and a 5.4 percent limited partner interest.

(5) LP represents Limited Partnership.

Earnings (losses) from our unconsolidated affiliates are as follows for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Alliance Pipeline Limited Partnership[1]	$ 1	$ 21	$ 23
Bastrop Company	(6)	(5)	—
Eagle Point Cogeneration Partnership[2]	—	—	22
EGE Fortuna	3	6	3
EGE Itabo	1	(2)	5
Great Lakes Gas Transmission	57	63	55
Habibullah Power	(1)	10	2
Midland Cogeneration Venture	32	28	23
Noric Holdings I	10	4	4
Saba Power Company	4	7	—
Other	(11)	16	49
Proportional share of income of investee	90	148	186
Impairment charges and gains and losses on sales of investments	(128)	(47)	10
Other	26	12	24
Total earnings (loss) from unconsolidated affiliates	$ (12)	$113	$220

(1) We sold our interest in this investment.
(2) Consolidated in January 2002.

Our impairment charges and gains and losses on sales of equity investments during 2003, 2002 and 2001 consisted of the following:

Investment	Pre-tax Gain (Loss)	Cause of Impairments or Gain (Loss)
	(In millions)	
2003		
Bastrop Company	$ (43)	Decision to sell investment
Dauphin Island Gathering/Mobile Bay Processing	(86)	Decline in the investments' fair value based on the devaluation of the underlying assets
Other investments	1	
	$(128)	
2002		
Aux Sable NGL	$ (47)	Sale of investment
2001		
Deepwater Investors	$ 13	Sale of investment
Other investments	(3)	
	$ 10	

Below is summarized financial information of our proportionate share of unconsolidated affiliates. This information 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 $98 million, $127 million and $136 million in 2003, 2002 and 2001, which includes $17 million, $6 million and $14 million of returns of capital, in 2003, 2002 and 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 $20 million, $25 million and $40 million in 2003, 2002 and 2001 and total assets of $536 million and $382 million as of December 31, 2003 and 2002.

	Year Ended December 31,		
	2003	2002	2001
	(Unaudited) (In millions)		
Operating results data:			
Operating revenues	$807	$799	$964
Operating expenses	590	542	632
Income from continuing operations	90	125	186
Net income	90	148	186

	December 31,	
	2003	2002 (Restated)
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 468	$ 438
Non-current assets	2,386	2,538
Short-term debt	99	92
Other current liabilities	249	240
Long-term debt	905	1,015
Other non-current liabilities	181	170
Minority interest	71	—
Equity in net assets	1,349	1,459

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

	2003	2002	2001
	(In millions)		
Revenues	$1,093	$1,616	$1,889
Cost of sales	87	178	227
Reimbursement for operating expenses	4	3	11
Charges from affiliates	331	354	335
Other income	6	6	8

Related Party Transactions

We enter into transactions with other El Paso subsidiaries and unconsolidated affiliates in the ordinary course of business to transport, sell and purchase natural gas and liquids and various contractual agreements for trading activities. In February 2001, we transferred our natural gas and power trading activities to El Paso Merchant Energy Company, an affiliate and subsidiary of El Paso, in exchange for a 22 percent interest in El Paso Merchant Energy, L.P. The transfer was based on estimated fair value of contracts transferred, and the investment was accounted for on a cost basis. In September 2001, we redeemed this interest. As a result, operational related party transactions that had previously been with an unconsolidated affiliate are now with an affiliate. For the years ended December 31, 2003, 2002 and 2001 we recognized revenues with El Paso Merchant Energy L.P. of $750 million, $1,085 million and $1,555 million which were primarily with our Production segment. We had cost of sales of $27 million, $102 million and $85 million with El Paso Merchant Energy L.P. for 2003, 2002 and 2001.

El Paso allocates a portion of its general and administrative expenses to us. The allocation is based on the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. For the years ended December 2003, 2002 and 2001, the annual charges were $152 million, $146 million and $193 million. During 2003, 2002 and 2001 El Paso Natural Gas Company and Tennessee Gas Pipeline Company allocated payroll and other expenses to us associated with our shared pipeline services. The allocated expenses are based on the estimated level of staff and their expenses to provide the services. For the years ended December 2003, 2002 and 2001 the annual charges were $48 million, $40 million and $34 million. El Paso also provides our production segment administrative and other shared production services and allocated $122 million, $155 million and $102 million in 2003, 2002 and 2001. We believe the allocation methods are reasonable.

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We have historically and consistently borrowed cash from El Paso under this program. As of December 31, 2003 and December 31, 2002, we had borrowed $906 million and $2,374 million. The market rate of interest as of December 31, 2003 was 2.8% and at December 31, 2002, it was 1.5%. On December 31, 2003, El Paso's Board of Directors authorized a capital contribution of $1.5 billion to us. In addition, we had a demand note receivable with El Paso of $275 million at December 31, 2003, at an interest rate of 1.7%. At December 31, 2002, the demand note receivable was $199 million at an interest rate of 2.2%.

At December 31, 2003 and December 31, 2002, we had accounts and notes receivable from related parties of $167 million and $322 million. In addition, we had a non-current note receivable from a related party of $127 million and $126 million included in other non-current assets at December 31, 2003 and at December 31, 2002.

At December 31, 2003 and December 31, 002, we had other accounts payable to related parties of $110 million and $87 million.

In 2003, El Paso made a capital contribution of $24 million to us. This contribution is reflected in our stockholder's equity statement as an increase in our additional paid in capital.

In March 2002, we acquired assets with a net book value, net of deferred taxes, of approximately $8 million from El Paso.

Additionally, we sold natural gas and oil properties to another subsidiary of El Paso in 2002. Net proceeds from these sales were $404 million, and because this sale involved entities under the common control of El Paso, we did not recognize a gain or loss on the properties sold. The proceeds originally exceeded the net book value by $32 million which we recorded as an increase to paid in capital. As a result of the restatement of our natural gas and oil reserve estimates, we restated the net book value of the properties sold and accordingly increased our additional paid in capital by $138 million, bringing the total adjustment to equity for this sale to $170 million.

In November 2002, we sold our stock in Coastal Mart, Inc., one of our wholly-owned subsidiaries, to El Paso Remediation Company, a wholly owned subsidiary of El Paso. We recorded a receivable of $42 million, which was based on the book value of the company (since the sale occurred between entities under common control). We did not recognize a gain or loss on this sale.

In December 2002, El Paso contributed to us its interest in one of its subsidiaries to us that had a book value of $139 million. At the time it was contributed, we reflected the contribution in our 2002 balance sheet as minority interest of consolidated subsidiaries. During 2003, we revised our 2002 balance sheet to reclassify this contribution from minority interest to paid in capital. This revision had no impact on our statements of income, cash flows or comprehensive income.

23. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, as restated to reflect the impacts of the revisions of our natural gas and oil reserves and other resulting matters as further described in Note 1 is summarized below:

	Quarters Ended				
	March 31 (Restated)	June 30 (Restated)	September 30 (Restated)	December 31	Total
			(In millions)		
2003[1]					
Operating revenues	$ 738	$ 610	$506	$ 520	$ 2,374
Ceiling test charges	1	20	80	8	109
Loss (gain) on long-lived assets	8	(25)	5	109	97
Operating income (loss)	276	207	45	(8)	520
Income (loss) from continuing operations	136	32	(20)	27	175
Discontinued operations, net of income taxes	(222)	(916)	(49)	(110)	(1,297)
Cumulative effect of accounting changes, net of income taxes	(12)	—	—	—	(12)
Net loss	(98)	(884)	(69)	(83)	(1,134)

	Quarters Ended				
	March 31 (Restated)	June 30 (Restated)	September 30 (Restated)	December 31 (Restated)	Total (Restated)
			(In millions)		
2002[1]					
Operating revenues	$1,697	$ 758	$669	$ 702	$ 3,826
Ceiling test charges	4	514	—	3	521
Loss (gain) on long-lived assets	(11)	(10)	1	13	(7)
Operating income (loss)	597	(198)	156	222	777
Income (loss) from continuing operations	332	(271)	112	143	316
Discontinued operations, net of income taxes	60	(116)	(93)	(216)	(365)
Cumulative effect of accounting changes, net of income taxes	—	14	—	—	14
Net income (loss)	392	(373)	19	(73)	(35)

(1) Our petroleum markets and coal mining operations are classified as discontinued operations. See Note 10 for further discussion.

24. Supplemental Natural Gas and Oil Operations (Unaudited)

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 10 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 and Indonesia.

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[(1)]	Brazil	Other Countries[(2)]	Worldwide
2003					
Natural gas and oil properties:					
Costs subject to amortization	$6,831	$ 861	$146	$47	$7,885
Costs not subject to amortization	119	146	117	7	389
	6,950	1,007	263	54	8,274
Less accumulated depreciation, depletion and amortization	5,295	650	58	20	6,023
Net capitalized costs[(3)]	$1,655	$ 357	$205	$34	$2,251
2002 (Restated)					
Natural gas and oil properties:					
Costs subject to amortization	$6,353	$ 608	$ —	$ 8	$6,969
Costs not subject to amortization	314	177	—	—	491
	6,667	785	—	8	7,460
Less accumulated depreciation, depletion and amortization	5,085	456	—	3	5,544
Net capitalized costs	$1,582	$ 329	$ —	$ 5	$1,916

(1) As of September 2004, we have sold our production operations in Canada.

(2) Includes international operations in Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.

(3) In January 1, 2003, we adopted SFAS No. 143. Included in our net capitalized costs at December 31, 2003 are SFAS No. 143 asset values of $77 million primarily for the U.S. Prior period presentation was not adjusted as amounts were adjusted through a one-time cumulative adjustment which is further discussed on Note 2.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

	United States	Canada[1]	Brazil	Other Countries[2]	Worldwide
			(In millions)		
2003					
Property acquisition costs					
Proved properties	$ —	$ 1	$—	$—	$ 1
Unproved properties	9	10	4	—	23
Exploration costs[3]	216	44	95	11	366
Development costs[3][4]	270	57	—	2	329
Total costs expended	$ 495	$112	$99	$13	$ 719
Plus: Asset Retirement Obligation costs[4]	77	—	—	—	77
Less: Actual Retirement expenditures	(7)	—	—	—	(7)
Total costs incurred	$ 565	$112	$99	$13	$ 789
2002 (Restated)[5]					
Property acquisition costs					
Proved properties	$ 23	$ 6	$—	$—	$ 29
Unproved properties	12	7	—	—	19
Exploration costs	197	70	—	—	267
Development costs	569	80	—	2	651
Total costs incurred	$ 801	$163	$—	$ 2	$ 966
2001 (Restated)[5]					
Property acquisition costs					
Proved properties	$ 87	$232	$—	$—	$ 319
Unproved properties	33	16	—	—	49
Exploration costs	182	22	—	—	204
Development costs	954	102	—	—	1,056
Total costs incurred	$1,256	$372	$—	$—	$1,628

(1) As of September 2004, we have sold our production operations in Canada.

(2) Includes international operations in Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.

(3) Excludes $57 million that was paid by third parties under net profits interest agreements.

(4) In January 2003, we adopted SFAS No. 143, "Asset Retirement Obligations". Prior period presentation was not adjusted as amounts were adjusted through a one-time cumulative adjustment of approximately $6 million after tax, primarily in the U.S. which is further discussed in Note 2.

(5) We have reclassified some of our development costs to exploration costs as a result of the restatement of our natural gas and oil reserves.

In our January 1, 2004 reserve report, the amounts estimated to be spent in 2004, 2005 and 2006 to develop our worldwide booked proved undeveloped reserves are $248 million, $167 million and $321 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, 2003, pending determination of proved reserves. Capitalized interest of $9 million, $10 million, and $4 million for the years ended December 31, 2003, 2002 and 2001 is included in the presentation below (in millions):

	Cumulative Balance December 31,	Costs Excluded for Years Ended December 31,			Cumulative Balance December 31,
	2003	2003	2002	2001	2000
Worldwide[1]					
Acquisition	$212	$ 35	$38	$108	$31
Exploration	142	96	31	6	9
Development	35	3	—	30	2
	$389	$134	$69	$144	$42

(1) Includes operations in the U.S., Canada, Brazil, Hungary and Indonesia. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in 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 2004 through 2007. For the U.S., the amortization expense per Mcfe, including ceiling test charges, was $2.15, $2.99, and $2.07 in 2003, 2002, and 2001. Excluding, ceiling test charges, amortization expense would have been $1.90, $1.49 and $1.45 per Mcfe in 2003, 2002 and 2001. For Canada, the total amortization expense per Mcfe, including ceiling test charges, was $5.30, $4.81 and $16.15 in 2003, 2002 and 2001. Excluding ceiling test charges, amortization expense would have been $1.71, $0.90 and $2.54 per Mcfe in 2003, 2002 and 2001. In January 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations. For further discussion, see Note 2. Accretion expense per unit attributable to SFAS 143 was $0.08 in 2003.

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 at December 31, 2003 are presented below. Information in this table is based on the reserve report dated January 1, 2004, prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates for 84 percent and 16 percent of our properties, respectively. The total estimate of proved reserves prepared independently by Ryder Scott Company and Huddleston & Co., Inc., was within five percent of our internally prepared estimates for 2003 presented in the tables below. The information at December 31, 2003, 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. Reserve information as of and for the years ended December 31, 2001 and 2002 in the following tables has been restated (for a further discussion, see Note 1).

	Natural Gas (in Bcf)			
	U.S.	Canada[1]	Other Countries[2]	Worldwide
Net proved developed and undeveloped reserves[3]				
January 1, 2001 (Restated)	1,569	30	—	1,599
Revisions of previous estimates[4]	(97)	4	—	(93)
Extensions, discoveries and other	460	14	—	474
Purchases of reserves in place	11	46	—	57
Sales of reserves in place	(95)	—	—	(95)
Production	(373)	(13)	—	(386)
December 31, 2001 (Restated)	1,475	81	—	1,556
Revisions of previous estimates[4]	(164)	1	—	(163)
Extensions, discoveries and other	279	54	5	338

	Natural Gas (in Bcf)			
	U.S.	Canada[1]	Other Countries[2]	Worldwide
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	(504)	(23)	—	(527)
Production	(247)	(17)	—	(264)
December 31, 2002 (Restated)	839	96	5	940
Revisions of previous estimates[4]	(30)	2	—	(28)
Extensions, discoveries and other	91	36	31	158
Purchases of reserves in place	3	—	—	3
Sales of reserves in place[5]	(136)	(22)	—	(158)
Production	(142)	(15)	(1)	(158)
December 31, 2003	625	97	35	757
Proved developed reserves				
December 31, 2001 (Restated)	1,028	70	—	1,098
December 31, 2002 (Restated)	633	84	—	717
December 31, 2003	502	87	4	593

(1) As of September 2004, we have sold our production operations in Canada.

(2) Includes international operations in Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.

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

(4) Revisions reflect a number of items such as product price changes and changes in product differentials.

(5) Sales of reserves in place include 11,416 MMcf of natural gas conveyed to third parties under net profits interest agreements.

	Liquids[1] (in MBbls)				
	U.S.	Canada[2]	Brazil	Other Countries[3]	Worldwide
Net proved developed and undeveloped reserves[4]					
January 1, 2001 (Restated)	47,080	410	—	—	47,490
Revisions of previous estimates[5]	(6,010)	1,309	—	—	(4,701)
Extensions, discoveries and other	16,926	296	—	—	17,222
Purchases of reserves in place	16	3,857	—	—	3,873
Sales of reserves in place	(260)	(2)	—	—	(262)
Production	(8,226)	(561)	—	—	(8,787)
December 31, 2001 (Restated)	49,526	5,309	—	—	54,835
Revisions of previous estimates[5]	(1,946)	(103)	—	—	(2,049)
Extensions, discoveries and other	7,114	288	—	—	7,402
Purchases of reserves in place	—	—	—	—	—
Sales of reserves in place	(11,283)	(2,062)	—	—	(13,345)
Production	(6,928)	(1,053)	—	—	(7,981)
December 31, 2002 (Restated)	36,483	2,379	—	—	38,862
Revisions of previous estimates[5]	(2,264)	1	—	—	(2,263)
Extensions, discoveries and other	3,655	2,463	20,543	1,742	28,403
Purchases of reserves in place	43	—	—	—	43
Sales of reserves in place[6]	(1,019)	(1,548)	—	—	(2,567)
Production	(5,978)	(309)	—	—	(6,287)
December 31, 2003	30,920	2,986	20,543	1,742	56,191
Proved developed reserves					
December 31, 2001 (Restated)	38,776	4,378	—	—	43,154
December 31, 2002 (Restated)	28,465	2,379	—	—	30,844
December 31, 2003	23,136	1,708	—	—	24,844

(1) Includes oil, condensate and natural gas liquids. Our year end 2003 natural gas liquids were 13,722 MBbls.
(2) As of September 2004, we sold our production operations in Canada.
(3) Includes international operations in Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.
(4) Net proved reserves exclude royalties and interests owned by others (including net profits interest) and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(5) Revisions reflect a number of items such as product price changes and changes in product differentials.
(6) Sales of reserves in place include 513 MBbl of liquids conveyed to third parties under net profits interest agreements.

There are considerable 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 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 we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. 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, 2003.

In 2003, we entered into agreements to sell interests in a maximum of 42 wells to a subsidiary of Lehman Brothers and a wholly owned subsidiary of Nabors Industries Ltd. As the wells are developed, these parties will pay 70 percent of the drilling and completion costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, these parties receive an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 70 percent of the aggregate net profits of all wells until they have recovered 117.5 percent of their aggregate investment. Upon this recovery, the net profits interest will convert to a proportionately reduced 2 percent overriding royalty interest in the wells for the remainder of the wells' productive life. We do not guarantee a return or recovery of their costs or any return on their investment. All parties to the agreement have the right to cease participation in the agreement at any time. Upon ceasing participation in the agreement, they will continue to receive their net profits interest on wells previously started, but will relinquish their right to participate in any future wells. As of December 31, 2003, we have sold interests in 13 wells with total proved reserves of 11,416 MMcf of natural gas and 513 MBbl of liquids to them under these agreements. They have paid $57 million of drilling and development costs and were paid $7 million of the revenues net of $1 million of expenses associated with these wells for the year ended December 31, 2003. Subsequent to year end 2003, one party elected to cease further investment in the program.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	U.S.	Canada[1]	Brazil	Other Countries[2]	Worldwide
2003					
Net Revenues					
Sales to external customers[3]	$ 682	$ 68	$ —	$ 1	$ 751
Intersegment sales	109	—	—	—	109
Total	791	68	—	1	860
Production costs[4]	(114)	(8)	—	—	(122)
Depreciation, depletion and amortization[5]	(346)	(29)	—	(1)	(376)
Ceiling test and other charges	(34)	(74)	(5)	—	(113)
	297	(43)	(5)	—	249
Income tax expense	(106)	15	2	—	(89)
Results of operations from producing activities	$ 191	$ (28)	$ (3)	$—	$ 160
2002					
Net Revenues (Restated)[6]					
Sales to external customers[3]	$1,021	$ 68	$ —	$—	$1,089
Intersegment sales	106	—	—	—	106
Total	1,127	68	—	—	1,195
Production costs[4]	(162)	(18)	—	—	(180)
Depreciation, depletion and amortization	(446)	(21)	—	—	(467)
Ceiling test and other charges	(417)	(95)	—	—	(512)
	102	(66)	—	—	36
Income tax benefit	(35)	28	—	—	(7)
Results of operations from producing activities	$ 67	$ (38)	$ —	$—	$ 29
2001 (Restated)[6]					
Net Revenues					
Sales to external customers[3]	$1,697	$ 46	$ —	$—	$1,743
Intersegment sales	(35)	—	—	—	(35)
Total	1,662	46	—	—	1,708
Production costs[4]	(222)	(12)	—	—	(234)
Depreciation, depletion and amortization	(615)	(42)	—	—	(657)
Ceiling test and other charges	(257)	(225)	—	—	(482)
	568	(233)	—	—	335
Income tax (expense) benefit	(206)	98	—	—	(108)
Results of operations from producing activities	$ 362	$(135)	$ —	$—	$ 227

(1) As of September 2004, we have sold our production operations in Canada.
(2) Includes international operations in Hungary.
(3) Sales to external customers include sales to third parties and other El Paso affiliates.
(4) Include lease operating costs and production related taxes (including ad valorem and severance taxes).
(5) In January 2003 we adopted SFAS No. 143, which is further discussed in Note 2. Our 2003 depreciation, depletion and amortization includes accretion expense for SFAS No. 143 asset retirement obligations of $16 million primarily for the U.S.
(6) Amounts restated include depreciation, depletion and amortization expenses, ceiling test and other charges, income taxes and related subtotals and totals.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31 (in millions):

	U.S.	Canada[1]	Brazil	Other Countries[2]	Worldwide
2003					
Future cash inflows[3]	$ 4,445	$ 607	$ 588	$ 141	$ 5,781
Future production costs	(967)	(124)	(65)	(44)	(1,200)
Future development costs	(564)	(11)	(236)	(49)	(860)
Future income tax expenses	(362)	(28)	(75)	3	(462)
Future net cash flows	2,552	444	212	51	3,259
10% annual discount for estimated timing of cash flows	(735)	(154)	(128)	(21)	(1,038)
Standardized measure of discounted future net cash flows	$ 1,817	$ 290	$ 84	$ 30	$ 2,221
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 1,729	$ 290	$ 84	$ 30	$ 2,133
2002 (Restated)					
Future cash inflows[3]	$ 4,632	$ 458	$ —	$ 12	$ 5,102
Future production costs	(1,071)	(111)	—	(2)	(1,184)
Future development costs	(623)	(5)	—	(3)	(631)
Future income tax expenses	(465)	(4)	—	—	(469)
Future net cash flows	2,473	338	—	7	2,818
10% annual discount for estimated timing of cash flows	(738)	(117)	—	(1)	(856)
Standardized measure of discounted future net cash flows	$ 1,735	$ 221	$ —	$ 6	$ 1,962
Standardized measure of discontinued future net cash flows, including effects of hedging activities	$ 1,671	$ 221	$ —	$ 6	$ 1,898
2001 (Restated)					
Future cash inflows[4]	$ 4,261	$ 301	$ —	$ —	$ 4,562
Future production costs	(1,322)	(107)	—	—	(1,429)
Future development costs	(778)	(17)	—	—	(795)
Future income tax expenses	—	—	—	—	—
Future net cash flows	2,161	177	—	—	2,338
10% annual discount for estimated timing of cash flows	(807)	(65)	—	—	(872)
Standardized measure of discounted future net cash flows	$ 1,354	$ 112	$ —	$ —	$ 1,466
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 1,974	$ 112	$ —	$ —	$ 2,086

(1) As of September 2004, we have sold our production operations in Canada.

(2) Includes international operations in Hungary and Indonesia. As of September 2004, we have sold substantially all of our operations in Indonesia.

(3) Excludes $139 million and $111 million of future net cash outflows attributable to hedging activities during 2003 and 2002.

(4) Excludes $684 million of future net cash inflows attributable to hedging activities during 2001.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end commodity prices, adjusted for transportation and other charges. At December 31, 2003, the prices used were $30.90 per Bbl of oil, $5.76 per Mcf of gas and $22.00 per Bbl of natural gas liquids. 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 excluding the effects of hedging activities (in millions):

	Years Ended December 31,[1]		
	2003	2002 (Restated)	2001 (Restated)
Sales and transfers of natural gas and oil produced net of production costs	$ (738)	$(1,013)	$(1,474)
Net changes in prices and production costs	666	1,980	(2,953)
Extensions, discoveries and improved recovery, less related costs	556	680	501
Changes in estimated future development costs	(25)	46	123
Previously estimated development costs incurred during the period	50	91	26
Revisions of previous quantity estimates	(111)	(366)	(118)
Accretion of discount	218	147	475
Net change in income taxes	8	(216)	1,026
Purchases of reserves in place	7	—	84
Sales of reserves in place	(417)	(1,195)	(92)
Changes in production rates, timing and other	45	342	139
Net change	$ 259	$ 496	$(2,263)

(1) Includes operations in the U.S., Canada, Brazil, Hungary and Indonesia. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
El Paso CGP Company:

In our opinion, the consolidated financial statements listed in the Index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso CGP Company and its subsidiaries (the "Company") at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 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 the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, the 2002 and 2001 consolidated financial statements have been restated principally to reflect the financial statement impact of the revision in the Company's estimates of its proved natural gas and oil reserves. The Company's plans with regard to its current liquidity position are also discussed in Note 1.

As discussed in Notes 2 and 6, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* on January 1, 2003; SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; SFAS No. 142, *Goodwill and Other Intangible Assets* and SFAS 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* on July 1, 2002; EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2* on October 1, 2002; and SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* on January 1, 2001.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
October 8, 2004

SCHEDULE II

EL PASO CGP COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2003, 2002 and 2001
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2003					
Allowance for doubtful accounts	$ 21	$ (1)	$ —	$ 17	$ 37
Valuation allowance on deferred tax assets	27	(26)[1]	—	—	1
Legal reserves	49	(3)	(16)	(3)	27
Environmental reserves	62	12	(10)	67[2]	131
Provision for refund	4	(3)	(1)	—	—
2002					
Allowance for doubtful accounts	$ 23	$ 1	$ (7)[3]	$ 4	$ 21
Valuation allowance on deferred tax assets	24	3	—	—	27
Legal reserves	51	11	(26)[4]	13[5]	49
Environmental reserves	163	9	(16)	(94)[6]	62
Provision for refund	5	7	(8)	—	4
2001					
Allowance for doubtful accounts	$ 10	$ 19	$ (6)[3]	$ —	$ 23
Valuation allowance on deferred tax assets	5	19[1]	—	—	24
Legal reserves	23	27[7]	—	1	51
Environmental reserves	13	151[3]	(1)	—	163
Provision for refund	—	5	—	—	5

(1) Relates primarily to foreign ceiling test charges and revisions of future revenue estimates.

(2) Relates primarily to retained liabilities previously classified in our petroleum discontinued operations.

(3) Relates primarily to accounts written off.

(4) Relates primarily to payments for various litigation reserves.

(5) Relates to legal reserves previously imbedded in environmental reserves.

(6) In November 2002, we sold Coastal Mart, Inc. to an affiliate of El Paso which included environmental reserves of $95 million.

(7) These amounts primarily relate to additional liabilities recorded in connection with changes in our estimates of these liabilities. See Note 6 for a further discussion of this change.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

In February 2004, El Paso completed the annual review of its December 31, 2003 natural gas and oil reserve estimates, including our reserve estimates. As a result of this review, El Paso reduced our proved natural gas and oil reserve estimates by approximately 1.0 trillion cubic feet. In May 2004, El Paso announced that, after further review and the completion of an independent investigation into the factors that led to this reserve adjustment, it believed that this reserve adjustment related to prior periods and the financial statement amounts derived from these estimates would require a restatement of prior period financial statements. The results of this independent investigation indicated that certain employees used aggressive and, at times, unsupportable methods to book proved reserves. In addition, the investigation concluded that certain employees provided proved reserve estimates that they knew or should have known were incorrect at the time they were reported. Consequently, we have restated our historical financial information. The restatement impacted the years from 1999 through 2002 and the first nine months of 2003. This restatement, as well as specific information regarding its impact, is discussed in Item 8, Financial Statements and Supplementary Data, Note 1.

We have identified deficiencies in our internal controls that did not prevent the overstatement of our natural gas and oil reserves. These deficiencies, which we believe constituted a material weakness in our internal controls over financial reporting, included a weak control environment surrounding the booking of our natural gas and oil reserves in the Production segment, inadequate controls over system access, inadequate documentation of policies and procedures, and ineffective controls to monitor compliance with existing policies and procedures.

Our management, at the direction of El Paso's Board of Directors, is actively working to improve the control environment and implement controls and procedures that will ensure the integrity of our reserve booking process. As a first step in that process, individuals have been added to El Paso's Board of Directors and executive management team with extensive experience in the natural gas and oil industry, and with experience in the preparation of natural gas and oil reserve estimates. We have also implemented the following controls:

- Formed an internal committee to provide oversight over the reserve estimation process, which is staffed with appropriate technical, financial reporting and legal expertise;
- Continued to use an independent third-party engineering firm that is selected by and reports annually to the Audit Committee of El Paso's Board of Directors with a subsequent report by the Audit Committee to the full Board of Directors;
- Formed a centralized reserve reporting function, staffed primarily with newly hired personnel that have extensive industry experience, that is separate from the operating divisions and reports directly to the president of Production and Non-regulated Operations;
- Restricted security access to the reserve system to centralized reserve reporting staff; and
- Revised our documentation of the procedures and controls for estimating proved reserves.

In addition, we expect to have the following controls fully in place by December 31, 2004:

- Improved training regarding SEC guidelines for booking proved reserves; and
- Enhanced internal audit reviews.

During 2003, we initiated a project to ensure compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX), which will apply to us at December 31, 2005. This project entailed a detailed review and documentation of the processes that impact the preparation of our financial statements, an assessment of the risks that could adversely affect the accurate and timely preparation of those financial statements, and the identification of controls in place to mitigate the risks of untimely or inaccurate preparation of those financial statements. Following the documentation of these processes, which was substantially concluded by December 2003, we initiated an internal review or "walk-through" of these financial processes by the financial management responsible for those processes to evaluate the design effectiveness of the controls identified to mitigate the risk of material misstatements occurring in our financial statements. We have also initiated a detailed process to evaluate the operating effectiveness of our controls over financial reporting. This process involves testing the controls for effectiveness, including a review and inspection of the documentary evidence supporting the operation of the controls on which we are placing reliance.

As a result of these efforts to ensure compliance with Section 404 of SOX, we have become aware of deficiencies in our internal controls over financial reporting in other areas of the company. The deficiencies include inadequate change management and security access to our information systems, lack of segregation of duties related to manual journal entry preparation and procurement activities, lack of formal documentation of policies and procedures, and untimely preparation and review of volume and account reconciliations. Although we have not formally assessed the materiality of each deficiency identified, we believe that the deficiencies in the aggregate constitute a material weakness in our internal controls.

We are actively remediating these deficiencies and have already implemented action plans for the following:

- Developing and implementing standard information system policies to govern change management and security access to our information systems across the company;
- Modifying systems and procedures to ensure appropriate segregation of responsibilities for manual journal entry preparation;
- Formalizing our account reconciliation policy and timely completing all material account reconciliations; and
- Developing and implementing formal training to educate company personnel on management's responsibilities mandated by SOX Section 404, the components of the internal control framework on which we rely and the relationship to our company values including accountability, stewardship, integrity and excellence.

We are in the process of implementing the following action plans and expect to have them fully implemented by December 31, 2004:

- Modifying systems and/or procedures to ensure appropriate segregation of responsibilities for procurement activities;
- Implementing an account reconciliation tool to facilitate the monitoring of compliance with our account reconciliation policy;
- Evaluating, formalizing and communicating required policies and procedures;
- Implementing appropriate monitoring activities to ensure compliance with the company's policies and procedures; and
- Reviewing the finance and accounting staffing.

Many of the deficiencies in our internal controls that we have identified are likely the result of significant changes the company has undergone during the past five years as a result of major acquisitions and reorganizations. We currently have company-wide efforts underway to formalize and improve our internal controls and effectively remediate all of the deficiencies described above. We have also performed additional analysis and procedures related to the deficiencies identified and have concluded that the deficiencies have not resulted in any material errors in these financial statements. As we continue our SOX Section 404 compliance efforts, including the testing of the effectiveness of our internal controls, we may identify additional deficiencies in our system of internal controls over financial reporting that either individually or in the aggregate may represent a material weakness requiring additional remediation efforts. We did not make any changes to our internal controls over financial reporting during the quarter ended December 31, 2003, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. However, as we discussed above, since December 31, 2003, we have made significant changes to our internal controls.

We have communicated to El Paso's Audit Committee and to our external auditors the deficiencies in our internal controls over financial reporting as well as the remediation efforts that we have underway. Our management, with the oversight of its Audit Committee, is committed to effectively remediating known deficiencies as expeditiously as possible and continuing its efforts to comply with Section 404 of the Sarbanes Oxley Act of 2002 by December 31, 2005.

We undertook, in a separate evaluation under the supervision of our principal executive and principal financial officers, and with the participation of other members of our management, a review of our disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities and Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As a result of the deficiencies and material weaknesses identified above, we concluded that our disclosure controls and procedures were ineffective as of December 31, 2003. To address the deficiencies and material weaknesses described above, we significantly expanded our disclosure controls and procedures to include additional analysis and other post-closing procedures to ensure our disclosure controls and procedures were effective over the preparation of these financial statements.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of October 11, 2004, regarding our executive officers and directors. Directors are elected annually by our parent, and hold office until their successors are elected and duly qualified. Each executive officer named in the following table has been elected to serve until his successor is duly appointed or elected or until his earlier removal or resignation from office. Information regarding our executive officers may be found in Part I, Item I, Business, and is incorporated herein by reference.

Name	Age	Position
Douglas L. Foshee	45	Director; Chairman of the Board, President and Chief Executive Officer
D. Dwight Scott	41	Director; Executive Vice President and Chief Financial Officer
Robert W. Baker	48	Director; Executive Vice President and General Counsel

Douglas L. Foshee has served as our Chairman of the Board, President and CEO since January 2004. Mr. Foshee has been President, Chief Executive Officer, and a Director of El Paso since September 2003. Mr. Foshee became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. In December 2003, several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, filed for bankruptcy protection whereby the subsidiaries will jointly resolve their asbestos claims. Prior to that, Mr. Foshee was President, Chief Executive Officer, and Chairman of the Board at Nuevo Energy Company. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Operating Officer and Chief Executive Officer. He held various positions in finance and new business ventures with ARCO International Oil and Gas Company and spent seven years in commercial banking, primarily as an energy lender.

D. Dwight Scott has served as our Executive Vice President, Chief Financial Officer and as a Director since January 2004. 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. Mr. Scott was Executive Vice President of Power for El Paso Merchant Energy from December 2001 to June 2002, and he served as Chief Financial Officer of El Paso Global Networks from October 2000 to November 2001. From January 1999 to October 2000, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

Robert W. Baker has served as our Executive Vice President and General Counsel since January 2004 and as a Director since April 2004. Mr. Baker has been Executive Vice President and General Counsel of El Paso since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. 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.

There are no family relationships among any of our executive officers or directors, and, unless described herein, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer or a director.

We are a wholly-owned direct subsidiary of El Paso and rely on El Paso for certain support services. As a result, we do not have a separate corporate audit committee or audit committee financial expert. Also, we have not adopted a separate code of ethics. However, our executives are subject to El Paso's Code of Business Conduct which is available for your review at El Paso's website, www.elpaso.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation of Executive Officers. This table and narrative text discusses the compensation paid in 2003, 2002 and 2001 by our affiliate to our Chief Executive Officer and our two other most highly compensated executive officers at December 31, 2003. We had no other executive officers during 2003. In addition, as required by SEC rules, we have provided the compensation information for Messrs. Kuehn and Wise who each served as our CEO at some point during 2003. The compensation reflected for each individual was for their services provided in all capacities to El Paso and its subsidiaries including us. This table also identifies the principal capacity in which each of the executives named in this Annual Report on Form 10-K served us at the end of fiscal year 2003.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Other Annual Compensation ($) (3)	Restricted Stock Awards ($) (4)	Securities Underlying Options (#)	Long-Term Incentive Plan Payouts ($) (5)	All Other Compensation ($) (6)
D. Dwight Scott	2003	$ 517,504	$ 750,000	—	$ —	—	—	$ 511,775
Executive Vice	2002	$ 387,504	$ —	—	$ —	—	—	$ 71,108
President and Chief Financial Officer	2001	$ 252,091	$ 360,039	—	$ 179,961	137,000	—	$ 59,628
Peggy A. Heeg	2003	$ 467,512	$ —	—	$ —	—	—	$ 2,257,526
Former Executive	2002	$ 445,008	$ —	—	$ —	—	—	$ 108,024
Vice President and General Counsel	2001	$ 235,004	$ 350,026	—	$ 174,084	157,229	—	$ 719,366
Ronald L. Kuehn, Jr.(7) Former Chief Executive Officer	2003	$ 568,462	$ 600,000	—	$ 247,500	125,000	—	$ 1,748,825
William A. Wise(8)	2003	$ 297,918	$ —	$ 37,434	$ —	—	$2,166,750	$15,486,077
Former Chief	2002	$1,430,004	$ —	$229,728	$ —	—	—	$ 255,632
Executive Officer	2001	$1,305,425	$3,432,000	$210,481	$1,715,997	768,250	—	$ 3,771,994

(1) The amount reflected in the salary column for 2003 and 2002 for Ms. Heeg and Mr. Wise includes an amount for El Paso mandated reductions to fund certain charitable organizations.

(2) For fiscal year 2001, El Paso's incentive compensation plans required executives to receive a substantial part of their annual bonus in shares of restricted El Paso common stock. The amounts reflected in this column for 2001 represent a combination of the market value of the restricted stock and cash at the time awarded under the applicable El Paso incentive compensation plan.

(3) The amount reflected for Mr. Wise in fiscal year 2003 includes, among other things, $18,750 for a perquisite and benefit allowance and $9,638 in value attributed to use of El Paso's aircraft. The amount reflected for Mr. Wise in fiscal year 2002 includes, among other things, $90,000 for a perquisite and benefit allowance and $65,509 in value attributed to use of El Paso's aircraft. The amount reflected for Mr. Wise in 2001 includes, among other things, $90,000 for a perquisite and benefit allowance and $62,692 in value attributed to use of El Paso's aircraft. Except as noted, the total value of the perquisites and other personal benefits received by the other executives named in this Annual Report on Form 10-K in fiscal years 2003, 2002 and 2001 are not included in this column since they were below the Securities and Exchange Commission's reporting threshold.

(4) For fiscal year 2003, Mr. Kuehn received a grant of 50,000 shares of restricted El Paso common stock in connection with assumption of the interim CEO position of El Paso, the grant date value of which is reflected in this column. For fiscal year 2001, El Paso's incentive compensation plans provided for and encouraged participants to elect to take the cash portion of their annual bonus award in shares of restricted stock. The amounts reflected in this column for 2001 include the market value of restricted stock on the date of grant. The value of the shares of common stock issued has declined significantly since the date of grant. The total number of shares and value of restricted stock (including the amount in this column) held on December 31, 2003, is as follows:

Restricted El Paso Common Stock as of December 31, 2003

Name	Total Number of Restricted Stock (#)	Value of Restricted Stock ($)
D. Dwight Scott	58,444	$ 478,656
Peggy A. Heeg	43,089	$ 352,899
Ronald L. Kuehn, Jr.	—	$ —
William A. Wise	—	$ —

With the exception of Mr. Kuehn's grant, most of these shares of restricted stock are subject to a time-vesting schedule of four years from the date of grant (including the shares awarded as part of the annual bonus in 2001 described above) and other shares of restricted stock which are subject to both time-vesting and performance-vesting. With respect to performance vesting, if the required El Paso performance targets are not met within a four-year time period, all unvested shares are forfeited. Any dividends awarded on the restricted stock are paid directly to the holder of the El Paso common stock. These total values can be realized only if the executives named in this Annual Report on Form 10-K remain employees of El Paso for the required period of years and, with respect to performance vesting, the performance goals regarding stockholder value are reached.

(5) For fiscal year 2003, the amount reflected in this column is the value of shares of restricted El Paso common stock on the date they vested. These shares had been reported in a long-term incentive table in El Paso's proxy statement for the year in which those shares of restricted stock were originally granted, along with the necessary performance measures necessary for their vesting. No long-term incentive payouts were made in fiscal years 2002 and 2001.

(6) The compensation reflected in this column for fiscal year 2003 includes El Paso's contributions to the El Paso Retirement Savings Plan and supplemental company match for the El Paso Retirement Savings Plan under the El Paso Supplemental Benefits Plan, as follows:

El Paso's Contributions to the Retirement Savings Plan and Supplemental Company Match under the Supplemental Benefits Plan for Fiscal Year 2003

Name	Retirement Savings Plan ($)	Supplemental Benefits Plan ($)
D. Dwight Scott	$3,750	$8,025
Peggy A. Heeg	$3,059	$7,425
Ronald L. Kuehn, Jr.	$ —	$ —
William A. Wise	$9,000	$2,850

In addition, for fiscal year 2003 for Mr. Scott and Ms. Heeg, the amount in this column includes the value of special retention payments in the amount $500,000 and $525,000, respectively. In addition, for fiscal year 2003 for Ms. Heeg, the amount in this column includes $1,722,042 in severance paid under El Paso's Severance Pay Plan. In addition, for fiscal year 2003 for Mr. Kuehn, the amount in this column includes $881,588 for the value of the split-dollar life insurance policy transferred to him in January 2003, $619,723 for the tax gross-up associated with the transfer of the split-dollar life insurance policy, $100,000 in severance attributed to him ceasing as interim CEO of El Paso and non-employee director fees received for serving on El Paso's Board of Directors during 2003. In addition, for fiscal year 2003 for Mr. Wise, the amount in this column includes $15,474,227 ($15,326,532 of which includes his supplemental pension benefit earned during his employment) paid in connection with his termination.

(7) Mr. Kuehn served as CEO of El Paso from March 13, 2003 to September 1, 2003.

(8) Mr. Wise ceased to be CEO of El Paso on March 12, 2003. See Item 11, Executive Compensation for a description of Mr. Wise's employment agreement with El Paso and the severance benefits he received pursuant to his employment agreement.

El Paso Corporation Stock Option Grants

This table sets forth the number of El Paso stock options granted at fair market value to the executives named in this Annual Report on Form 10-K during the fiscal year 2003. In satisfaction of applicable SEC regulations, the table further sets forth the potential realizable value of such stock options in the year 2013 (the expiration date of the stock options) at an assumed annualized rate of stock price appreciation of 5% and 10% over the full ten-year term of the stock options. As the table indicates for the grant made on September 2, 2003, annualized stock price appreciation of 5% and 10% would result in stock prices in the year 2013 of approximately $11.96 and $19.05, respectively. Further as the table indicates for the grant made on March 21, 2003, annualized stock price appreciation of 5% and 10% would result in stock prices in the year 2013 of approximately $10.64 and $16.95, respectively. The amounts shown in the table as potential realizable values for all stockholders' stock (approximately $2.9 billion and $7.4 billion for the September grant and approximately $2.6 billion and $6.6 billion for the March grant), represent the corresponding increases in the market value of 633,912,031 shares of El Paso common stock outstanding as of December 31, 2003. No gain to the executive named in this Annual Report on Form 10-K is possible without an increase in stock price, which would benefit all stockholders. Actual gains, if any, on stock option exercises and El Paso common stock holdings are dependent on the future performance of El Paso common stock and overall stock market conditions. There can be no assurances that the potential realizable values shown in this table will be achieved.

El Paso Option Grants in 2003

	Individual Grants(1)				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
					If Stock Price at $11.96423 and $10.64483 in 2013	If Stock Price at $19.05104 and $16.95011 in 2013
Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to all Employees in 2003	Exercise Price ($/Share)	Expiration Date	5% ($)	10% ($)
Potential Value of all El Paso Common Stock Outstanding on December 31, 2003						
September 2, 2003 Grant	**N/A**	**N/A**	**N/A**	**N/A**	**$2,928,186,126**	**$7,420,598,558**
March 21, 2003 Grant	**N/A**	**N/A**	**N/A**	**N/A**	**$2,605,268,391**	**$6,602,261,617**
Ronald L. Kuehn, Jr.	125,000	11.10%	$6.53500	3/21/2003	$ 513,728	$ 1,301,888

(1) The El Paso stock options granted in 2003 to Mr. Kuehn vested in September 2003 when he ceased to be El Paso's interim CEO. No stock options were granted to any other of the named executives. There were no stock appreciation rights granted in 2003. Any unvested stock options become fully exercisable in the event of a "change in control" of El Paso. See Item 11, Executive Compensation of this Annual Report on Form 10-K for a description of El Paso's 2001 Omnibus Incentive Compensation Plan and the definition of the term "change in control." Under the terms of El Paso's 2001 Omnibus Incentive Compensation Plan, El Paso's Compensation Committee may, in its sole discretion and at any time, change the vesting of the stock options. Certain non-qualified stock options may be transferred to immediate family members, directly or indirectly or by means of a trust, corporate entity or partnership. Further, stock options are subject to forfeiture and/or time limitations on exercise in the event of termination of employment.

El Paso Corporation Option Exercises and Year-End Value Table

This table sets forth information concerning El Paso stock option exercises and the fiscal year-end values of the unexercised stock options, provided on an aggregate basis, for each of the executives named in this Annual Report on Form 10-K.

Aggregated Option Exercises in 2003 and Fiscal Year-End Option Values

			Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)(2)	
Name	Shares Acquired on Exercise (#)(1)	Value Realized ($)(1)	Exercisable	Unexercisable	Exercisable	Unexercisable
D. Dwight Scott	—	$ —	115,247	28,247	$ —	$ —
Peggy A. Heeg	11,333	$ 81,541	166,730	—	$ —	$ —
Ronald L. Kuehn, Jr.	—	$ —	614,300	—	$208,750	$ —
William A. Wise	100,000	$719,500	1,787,917(3)	—	$ —	$ —

(1) The amounts in these columns represent the number of El Paso shares and the value realized upon conversion of El Paso stock options into shares of El Paso's common stock that occurred during 2003 based upon the achievement of certain El Paso performance targets established when they were originally granted in 1999.

(2) The figures presented in these columns have been calculated based upon the difference between $8.205, the fair market value of El Paso's common stock on December 31, 2003, for each in-the-money stock option, and its exercise price. No cash is realized until

the shares received upon exercise of an option are sold. No executives named in this Annual Report on Form 10-K had stock appreciation rights that were outstanding on December 31, 2003.

(3) Includes 98,000 stock options held by the William & Marie Wise Family Ltd. Partnership.

EL PASO CORPORATION PENSION PLAN

Effective January 1, 1997, El Paso amended its pension plan to provide pension benefits under a cash balance plan formula that defines participant benefits in terms of a hypothetical account balance. Prior to adopting a cash balance plan, El Paso provided pension benefits under a plan (the "Prior Plan") that defined monthly benefits based on final average earnings and years of service. Under the cash balance plan, an initial account balance was established for each El Paso employee who was a participant in the Prior Plan on December 31, 1996. The initial account balance was equal to the present value of Prior Plan benefits as of December 31, 1996.

At the end of each calendar quarter, participant account balances are increased by an interest credit based on 5-Year Treasury bond yields, subject to a minimum interest credit of 4% per year, plus a pay credit equal to a percentage of salary and bonus. The pay credit percentage is based on the sum of age plus service at the end of the prior calendar year according to the following schedule:

Age Plus Service	Pay Credit Percentage
Less than 35	4%
35 to 49	5%
50 to 64	6%
65 and over	7%

Under El Paso's pension plan and applicable Internal Revenue Code provisions, compensation in excess of $200,000 cannot be taken into account and the maximum payable benefit in 2003 was $160,000. Any excess benefits otherwise accruing under El Paso's pension plan are payable under El Paso's Supplemental Benefits Plan. Participants will receive benefits in the form of a lump sum payment under the Supplemental Benefits Plans unless a valid irrevocable election was made to receive payment in a form other than lump sum prior to June 1, 2004.

Participants with an initial account balance on January 1, 1997 are provided minimum benefits equal to the Prior Plan benefit accrued as of the end of 2001. Upon retirement, certain participants (including Mr. Wise) are provided pension benefits that equal the greater of the cash balance formula benefit or the Prior Plan benefit. For Mr. Wise, the Prior Plan benefit reflects accruals through the end of 2001 and is computed as follows: for each year of credited service up to a total of 30 years, 1.1% of the first $26,800, plus 1.6% of the excess over $26,800, of the participant's average annual earnings during his five years of highest earnings.

Credited service as of December 31, 2001, for Mr. Wise is shown in the table below. Amounts reported under Salary and Bonus for each executive named in the Summary Compensation Table approximate earnings as defined under the pension plan.

Estimated annual benefits payable from the pension plan and El Paso Supplemental Benefits Plan upon retirement at the normal retirement age (age 65) for each named executive is reflected below (based on assumptions that each named executive receives base salary shown in the Summary Compensation Table with no pay increases, receives 50% of target annual bonuses beginning with bonuses earned for fiscal year 2004, and cash balances are credited with interest at a rate of 4% per annum):

Named Executive	Credited Service(1)	Pay Credit Percentage During 2003	Estimated Annual Benefits(2)
Dwight Scott	N/A	5%	$198,568
Peggy Heeg(3)	N/A	6%	$ 33,865
Ronald Kuehn(4)	N/A	7%	$ 78,093
William A. Wise(5)	30	7%	$881,725

(1) For Mr. Wise, credited service shown is as of December 31, 2001.

(2) For Mr. Wise, the amount reflected has been reduced as a result of his participation in the El Paso Alternative Benefits Program, as described in this Item 11 Executive Compensation. The Prior Plan minimum benefit for Mr. Wise is greater than his projected cash balance benefit at age 65.

(3) The amount reflected for Ms. Heeg is her vested pension benefit amount under both the El Paso Supplemental Benefits Plan and the tax-qualified pension plan as of her termination date of December 31, 2003, payable commencing at age 65.

(4) The amount reflected for Mr. Kuehn is his vested pension benefit amount under both the El Paso Supplemental Benefits Plan and the tax-qualified pension plan as of his termination date of September 2, 2003, payable commencing October 1, 2003 (at age 68). Mr. Kuehn has elected to receive his El Paso Supplemental Benefits Plan benefit in a lump sum of $79,211, minus amounts withheld for taxes. Mr. Kuehn has also elected to receive his benefit under the tax-qualified pension plan in a lump sum of $15,834. Additionally, due to Mr. Kuehn's previous employment with Sonat, he is also receiving an annual benefit (75% joint and survivor form of payment) under the tax-qualified pension plan equal to $69,309.

(5) The amount reflected for Mr. Wise is his vested pension benefit amount under both the El Paso Supplemental Benefits Plan and the tax-qualified pension plan as of his termination date of March 12, 2003, payable commencing at age 65. Mr. Wise has elected to receive his El Paso Supplemental Benefits Plan benefit in a lump sum of $15,326,532, minus amounts withheld for taxes. Mr. Wise elected to receive a single life annuity benefit under the tax-qualified pension plan equal to $97,520 annually.

EMPLOYMENT CONTRACTS, TERMINATION OF EMPLOYMENT AND CHANGE IN CONTROL ARRANGEMENTS

Employment Agreements

Former Employees

As part of the merger with Sonat, El Paso entered into a termination and consulting agreement with Ronald L. Kuehn, Jr., dated October 25, 1999. Under this agreement, Mr. Kuehn served as the non-executive Chairman of El Paso's Board of Directors through December 31, 2000, and received a fee of $20,833 per month from October 25, 1999 through December 31, 2000. In addition, Mr. Kuehn received the perquisites that were available to him prior to the merger with Sonat pursuant to this agreement, as well as non-cash compensation available to other non-employee directors. Starting on October 25, 1999, and for the remainder of his life, Mr. Kuehn will receive certain ancillary benefits made available to him prior to the merger with Sonat, including the provision of office space and related services, and payment of life insurance premiums sufficient to provide a death benefit equal to four times his base pay as in effect immediately prior to October 25, 1999. Mr. Kuehn and his eligible dependents will also receive retiree medical coverage. El Paso maintained a collateral assignment split-dollar life insurance policy to provide for the death benefit for Mr. Kuehn to satisfy its obligation to provide the life insurance referenced above. In January 2003, El Paso released the collateral assignment on the policy. El Paso recovered $1,116,303 from the policy's cash surrender value for premiums paid by El Paso and its predecessors for Mr. Kuehn under the policy and gave up the right to recoup $881,588, which was left in the policy to provide coverage under the policy until age 95. The release of the collateral assignment and the right to recoup $881,588 was treated as a transfer of property to Mr. Kuehn subject to ordinary income tax. El Paso paid Mr. Kuehn $619,723 to satisfy the tax liabilities related to the transfer of the policy. In March 2003, Mr. Kuehn, in an interim capacity, replaced Mr. Wise as Chief Executive Officer of El Paso. At that time, El Paso entered into an employment agreement with Mr. Kuehn effective upon his appointment as interim Chief Executive Officer of El Paso. Mr. Kuehn has also served as Chairman of the Board of El Paso since March 2003. Under his employment agreement, Mr. Kuehn received a monthly salary of $100,000 and was eligible to earn a target bonus amount equal to 100% of his annual salary based on El Paso's and his performance as determined by El Paso's Compensation Committee. Pursuant to his employment agreement, on the date Mr. Foshee began as the permanent Chief Executive Officer of El Paso, Mr. Kuehn received a pro-rated portion of his target bonus based on the number of months he served as the interim Chief Executive Officer in the amount of $600,000 and a termination payment in the amount of $100,000 for the time he served as interim Chief Executive Officer. Mr. Kuehn's employment agreement also provided for an award of 125,000 nonqualified stock options to purchase shares of El Paso's common stock and 50,000 shares of restricted stock of El Paso under the El Paso 2001 Omnibus Incentive

Compensation Plan. His stock options vested and all restrictions on his restricted stock lapsed on the date Mr. Foshee began as the permanent Chief Executive Officer of El Paso.

Effective as of March 12, 2003, Mr. Kuehn replaced William A. Wise as Chief Executive Officer and Chairman of the Board of Directors of El Paso pending selection of a permanent Chief Executive Officer. Under the terms of his pre-existing employment agreement with El Paso, Mr. Wise received the severance benefits set for in his pre-existing employment agreement for the remaining three-year term of his agreement consisting of his annual salary of $1,430,004, an annual bonus in the amount of $1,716,004, service credit and age credit for pension benefits and continued medical, dental and vision insurance. Effective in May 2004, payment to Mr. Wise of his annual salary was suspended. In May 2004, Mr. Wise initiated an arbitration in connection with his employment agreement. Mr. Wise asserts that he is entitled to additional perquisites under the terms of his pre-existing employment agreement. Mr. Wise is not entitled to receive benefits under his employment agreement that otherwise would arise in connection with any future change in control of El Paso. Any salary, bonus, or benefits received by Mr. Wise in connection with any full-time employment during the remaining three-year term will reduce the salary, bonus, or benefits payable to Mr. Wise under the terms of his agreement. In March 2003, El Paso transferred ownership of Mr. Wise's company-owned automobile to Mr. Wise and agreed to purchase his Houston residence, if timely requested to do so, at the greater of its appraised value or the amount of Mr. Wise's investment. In 1997, El Paso loaned Mr. Wise $1,564,000 with interest at 6.8% for the purchase of his Houston residence. On March 19, 2003, Mr. Wise repaid this loan in full with accrued interest, consisting of $1,564,000 in principal and $617,436 in interest. In 2001, El Paso loaned Mr. Wise $7,332,195 with interest at 4.99% to fund Mr. Wise's exercise of options to purchase El Paso common stock. This outstanding loan obligation became payable by Mr. Wise in full upon the cessation of his employment. On April 23, 2003, Mr. Wise repaid this loan in full with accrued interest, consisting of $7,332,195 in principal and $594,549 in interest. In addition, Mr. Wise held 1,887,917 vested El Paso stock options. These options are exercisable by Mr. Wise through March 12, 2006, unless they expire earlier in accordance with their terms. Any portion of these options not exercised by March 12, 2006 or any earlier applicable expiration date will be forfeited on that date. Of these 1,887,917 stock options, 100,000 were converted automatically into shares of El Paso common stock on October 25, 2003, with the value per option equal to the fair market value of El Paso common stock on that date. Mr. Wise forfeited 258,333 unvested stock options when he ceased to be an employee of El Paso on March 12, 2003. In addition, 491,639 shares of restricted El Paso common stock held by Mr. Wise as of March 12, 2003 became vested as of that date, and 139,609 shares of restricted stock were forfeited as of that date. Mr. Wise also became vested in 33,281 performance units, the performance cycle for which ended in June 2003, without value, and he forfeited 2,219 unvested performance units.

Benefit Plans

El Paso Severance Pay Plan. The El Paso Severance Pay Plan is a broad-based employee plan providing severance benefits following a "qualifying termination" for all salaried employees of El Paso and certain of its subsidiaries. The plan also includes an executive supplement, which provides enhanced severance benefits for certain executive officers of El Paso and certain of its subsidiaries, including Mr. Foshee, Mr. Scott, and Mr. Baker. The enhanced severance benefits available under the supplement include an amount equal to two times the sum of the officer's annual salary, including annual target bonus amounts as specified in the plan. A qualifying termination includes an involuntary termination of the officer as a result of the elimination of the officer's position or a reduction in force and a termination for "good reason" (as defined under the plan). In the event the El Paso Severance Pay Plan is terminated, the executive supplement will continue as a separate plan unless the action terminating the El Paso Severance Pay Plan explicitly terminates the supplement. The executive supplement of the El Paso Severance Pay Plan terminates on January 1, 2005, unless extended. In the event of a "change in control" (as defined in the El Paso Key Executive Severance Protection Plan) of El Paso, participants whose termination of employment entitles them to severance pay under the executive supplement and the El Paso Key Executive Severance Protection Plan will receive severance pay under the El Paso Key Executive Severance Protection Plan, rather than under the executive supplement.

El Paso 2004 Key Executive Severance Protection Plan. El Paso periodically reviews its benefits plans and engages Deloitte Consulting to make recommendations regarding its plans. Deloitte recommended that El Paso adopt a new executive severance plan that more closely aligns with current market arrangements than El Paso's Key Executive Severance Protection Plan and Employee Severance Protection Plan (as described below). In light of Deloitte's recommendation, El Paso adopted this plan in March 2004. This plan provides severance benefits following a "change in control" of El Paso for executives of El Paso and certain of its subsidiaries, as designated by El Paso's Board or Compensation Committee, including Mr. Foshee, Mr. Scott, and Mr. Baker. This plan is intended to replace the El Paso Key Executive Severance Protection Plan and Employee Severance Protection Plan, and participants are required to waive their participation under those plans (if applicable) as a condition to becoming participants in this plan. The benefits of the plan include: (1) a cash severance payment in an amount equal to three times the annual salary and target bonus for the CEO of El Paso, two times the annual salary and target bonus for executive vice presidents and senior vice presidents, including Mr. Scott, and one times the annual salary and target bonus for vice presidents; (2) a prorated portion of the executive's target bonus for the year in which the termination of employment occurs; (3) continuation of life and health insurance following termination for a period of 36 months for the CEO of El Paso, 24 months for executive vice presidents and senior vice presidents of El Paso, including Mr. Scott and Mr. Baker, and 12 months for vice presidents of El Paso; (4) a gross-up payment for any federal excise tax imposed on an executive in connection with any payment or distribution made by El Paso or any of its affiliates under the plan or otherwise; provided that in the event a reduction in payments in respect of the executive of 10% or less would cause no excise tax to be payable in respect of that executive, then the executive will not be entitled to a gross-up payment and payments to the executive shall be reduced to the extent necessary so that the payments shall not be subject to the excise tax; and (5) payment of legal fees and expenses incurred by the executive to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment of an executive in the plan within two years following the date of a change in control of El Paso, except where termination is by reason of death, disability, for "cause" (as defined in the plan) or instituted by the executive other than for "good reason" (as defined in the plan). Benefits are also payable under the plan for terminations of employment prior to a change in control of El Paso that arise in connection with, or in anticipation of, a change in control. Benefits are not payable for any termination of employment following a change in control of El Paso if (i) the termination occurs in connection with the sale, divestiture or other disposition of designated subsidiaries of El Paso, (ii) the purchaser or entity subject to the transaction agrees to provide severance benefits at least equal to the benefits available under the plan, and (iii) the executive is offered, or accepts, employment with the purchaser or entity subject to the transaction. A change in control of El Paso generally occurs if: (i) any person or entity becomes the beneficial owner of more than 20% of El Paso's common stock; (ii) a majority of the current members of the Board of Directors of El Paso or their approved successors cease to be directors of El Paso (or, in the event of a merger, the ultimate parent following the merger); or (iii) a merger, consolidation, or reorganization of El Paso, a complete liquidation or dissolution of El Paso, or the sale or disposition of all or substantially all of El Paso's and its subsidiaries' assets (other than a transaction in which the same stockholders of El Paso before the transaction own 50% of the outstanding common stock after the transaction is complete). This plan generally may be amended or terminated at any time prior to a change in control, provided that any amendment or termination that would adversely affect the benefits or protections of any executive under the plan shall be null and void as it relates to that executive if a change in control occurs within one year of the amendment or termination. In addition, any amendment or termination of the plan in connection with, or in anticipation of, a change in control which actually occurs shall be null and void. From and after a change in control, the plan may not be amended in any manner that would adversely affect the benefits or protections provided to any executive under the plan.

El Paso Key Executive Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a "change in control" of El Paso for certain officers of El Paso and certain of its subsidiaries. The benefits of the plan include: (1) an amount equal to three times the participant's annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination; (3) a supplemental pension payment calculated by adding three years of additional credited pension service; (4) certain additional payments to the terminated employee to cover excise taxes if the payments made under the plan are subject to excise taxes on golden parachute payments; and (5) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control of El Paso, except where termination is by reason of death, disability, for cause or instituted by the employee for other than "good reason" (as defined in the plan). A change in control of El Paso occurs if: (i) any person or entity becomes the beneficial owner of 20% or more of El Paso's common stock; (ii) any person or entity (other than El Paso) purchases the common stock by way of a tender or exchange offer; (iii) El Paso stockholders approve a merger or consolidation, sale or disposition or a plan of liquidation or dissolution of all or substantially all of El Paso's assets; or (iv) if over a two year period a majority of the members of the El Paso Board of Directors at the beginning of the period cease to be directors. A change in control has not occurred if El Paso is involved in a merger, consolidation or sale of assets in which the same stockholders of El Paso before the transaction own 80% of the outstanding common stock after the transaction is complete. This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan or be made following the occurrence of a change in control. This plan is closed to new participants, unless the El Paso Board of Directors determines otherwise.

El Paso Supplemental Benefits Plan. This plan provides for certain benefits to officers and key management employees of El Paso and its subsidiaries. The benefits include: (1) a credit equal to the amount that a participant did not receive under El Paso's Pension Plan because the Pension Plan does not consider deferred compensation (whether in deferred cash or deferred restricted common stock) for purposes of calculating benefits and eligible compensation is subject to certain Internal Revenue Code limitations; and (2) a credit equal to the amount of El Paso's matching contribution to El Paso's Retirement Savings Plan that cannot be made because of a participant's deferred compensation and Internal Revenue Code limitations. The plan may not be terminated so long as the El Paso Pension Plan and/or El Paso Retirement Savings Plan remain in effect. The management committee of this plan designates who may participate and also administers the plan. Benefits under El Paso's Supplemental Benefits Plan are paid upon termination of employment in a lump-sum payment. In the event of a change in control (as defined under the El Paso Key Executive Severance Protection Plan) of El Paso, the supplemental pension benefits become fully vested and nonforfeitable.

El Paso Senior Executive Survivor Benefits Plan. This plan provides certain senior executives (including each of the named executives in this Annual Report on Form 10-K, except for Ms. Heeg and Messrs. Wise and Kuehn who are no longer employees) of El Paso and its subsidiaries who are designated by the plan administrator with survivor benefit coverage in lieu of the coverage provided generally for employees under El Paso's group life insurance plan. The amount of benefits provided, on an after-tax basis, is two and one-half times the executive's annual salary. Benefits are payable in installments over 30 months beginning within 31 days after the executive's death, except that the plan administrator may, in its discretion, accelerate payments.

El Paso Benefits Protection Trust Agreement. El Paso maintains a trust for the purpose of funding certain of its employee benefit plans (including the El Paso severance protection plans described above). The trust consists of a trustee expense account, which is used to pay the fees and expenses of the trustee, and a benefit account, which is made up of three subaccounts and used to make payments to participants and beneficiaries in the participating plans. The trust is revocable by El Paso at any time before a "threatened change in control" (which is generally defined to include the commencement of actions that would lead to a "change in control" (as defined under the El Paso Key Executive Severance Protection Plan) of El Paso as to assets held in the trustee expense account, but is not revocable (except as provided below) as to assets held in the benefit account at any time. The trust generally becomes fully irrevocable as to assets held in the trust upon a threatened change in control. The trust is a grantor trust for federal tax purposes, and assets of the trust are subject to claims by El Paso's general creditors in preference to the claims of plan participants and beneficiaries. Upon a threatened change in control, El Paso must deliver $1.5 million in cash to the trustee expense account. Prior to a threatened change in control, El Paso may freely withdraw and substitute the assets held in the benefit account, other than the initially funded amount; however, no such assets may be withdrawn from the benefit account during a threatened change in control period. Any assets contributed to the trust during a threatened change in control period may be withdrawn if the threatened change in control period ends and there has been no threatened change in control. In addition, after a change in control of El Paso occurs, if the trustee determines that the amounts held in the trust are less than "designated percentages" (as defined in the Trust Agreement) with respect to each subaccount in the benefit account, the trustee must make a written demand on El Paso to deliver funds in an amount determined by the trustee sufficient to attain the designed percentages. Following a change in control and if the trustee has not been requested to pay benefits from any subaccount during a "determination period" (as defined in the Trust Agreement), El Paso may make a written request to the trustee to withdraw certain amounts which were allocated to the subaccounts after the change in control occurred. The trust generally may be amended or terminated at any time, provided that no amendment or termination may result, directly or indirectly, in the return of any assets of the benefit account to El Paso prior to the satisfaction of all liabilities under the participating plans (except as described above) and no amendment may be made unless El Paso, in its reasonable discretion, believes that such amendment would have no material adverse effect on the amount of benefits payable under the trust to participants. In addition, no amendment may be made after the occurrence of a change in control which would (i) permit El Paso to withdraw any assets from the trustee expense account, (ii) directly or indirectly reduce or restrict the trustee's rights and duties under the trust, or (iii) permit El Paso to remove the trustee following the date of the change in control.

El Paso Alternative Benefits Program (ABP). In 2001, Mr. Wise reduced the balance of certain compensation payable to him under the El Paso Supplemental Benefits Plan by $5,000,000, in exchange for the right to participate in the ABP. The program provides for a loan to purchase a life insurance policy under a family trust. The amount of the loan to Mr. Wise was $9,000,000. The trust is the named beneficiary under the life insurance policy, and the loan with accrued interest will be repaid, on an after-tax basis, with proceeds of the policy after the participant's, or his spouse's death, whichever is later. The compensation that was reduced had been awarded in prior years and was disclosed as required in earlier proxy statements of El Paso. The cost of this program will not exceed the cost El Paso would have paid as compensation with respect to the reduced amounts. An amount of $2,608 was imputed as income in 2003 for Mr. Wise and is included, to the extent required under the rules of the SEC, in the "Other Annual Compensation" column to the Summary Compensation Table. This program is now closed to new participants.

Compensation Plans

El Paso 2001 Omnibus Incentive Compensation Plan. This plan provides for the grant to officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. A maximum of 6,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator designates which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a "change in control" (defined in substantially the same manner as under the El Paso Key Executive Severance Protection Plan) of El Paso occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; (3) designated amounts of performance units become fully vested; (4) all restrictions placed on awards of restricted stock automatically lapse; and (5) the current year's target bonus amount becomes payable for each officer participating in the plan within 30 days, assuming target levels of performance were achieved by El Paso and the officer for the year in which the change in control occurs, or the prior year if target levels have not been established for the current year, except that no bonus amounts will become payable in connection with a change in control that results solely from a change to the Board of Directors of El Paso. The plan generally may be amended or terminated at any time. Any amendment following a change in control that impairs participants' rights requires participant consent.

El Paso 1999 Omnibus Incentive Compensation Plan and 1995 Omnibus Compensation Plan — Terminated Plans. These plans provided for the grant to eligible officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. These plans have been replaced by the El Paso 2001 Omnibus Incentive Compensation Plan. Although these plans have been terminated with respect to new grants, certain stock options and shares of restricted stock remain outstanding under them. If a "change in control" of El Paso occurs, all outstanding stock options become fully exercisable and restrictions placed on restricted stock lapse. For purposes of the plans, the term "change in control" has substantially the same meaning given such term in the El Paso Key Executive Severance Protection Plan.

El Paso Strategic Stock Plan. This plan is an equity compensation plan that has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to non-employee members of the Board of Directors, officers and key employees of El Paso and its subsidiaries primarily in connection with El Paso's strategic acquisitions. A maximum of 4,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator determines which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a change in control, as defined earlier under the El Paso Key Executive Severance Protection Plan, of El Paso 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 stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan.

El Paso Omnibus Plan for Management Employees. This plan is an equity compensation plan which has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to salaried employees (other than employees covered by a collective bargaining agreement) of El Paso and its subsidiaries. A maximum of 58,000,000 shares in the aggregate may be subject to awards under this plan. If a change in control, as defined earlier under the El Paso Key Executive Severance Protection Plan, of El Paso 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 stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

None of our Common Stock is held by any director or executive officer. No family relationship exists between any of our directors or executive officers. The following information relates to the only entity known to us to be the beneficial owner, as of August 31, 2004, of more than five percent of our voting securities.

Title of Class	Name	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	El Paso Corporation 1001 Louisiana Street Houston, Texas 77002	1,000 shares	100%

The following table sets forth, as of September 15, 2004 (unless otherwise indicated), certain information with respect to the following individuals to the extent they own shares of common stock of El Paso, our parent.

Title of Class	Name of Beneficial Owner	Beneficial Ownership (Excluding Options)(1)	Stock Options(2)	Total	Percent of Class
Common Stock	D.L. Foshee	507,199	200,000	707,199	*
Common Stock	D.D. Scott	169,095	140,247	309,342	*
Common Stock	R.W. Baker	145,240	183,709	328,949	*
Common Stock	P.A. Heeg	72,803(3)	166,730	239,533	*
Common Stock	R.L. Kuehn, Jr.	313,500(4)	614,300	927,800	*
Common Stock	W.A. Wise	1,796,658(5)	1,621,917(6)	3,418,575	*
Common Stock	Directors and executive officers as a group 6 persons total, including those individuals listed above	3,004,495	2,926,903	5,931,398	.1%

* Less than 1%

(1) The individuals named in the table have sole voting and investment power with respect to shares of El Paso common stock beneficially owned. This column also includes shares of common stock held in the El Paso Benefits Protection Trust (as of September 15, 2004) as a result of deferral elections made in accordance with El Paso's benefit plans. These individuals share voting power with the trustee under that plan and receive dividends on such shares, but do not have the power to dispose of, or direct the disposition of, such shares until such shares are distributed. In addition, some shares of common stock reflected in this column for certain individuals are subject to restrictions.

(2) The directors and executive officers have the right to acquire the shares of common stock reflected in this column within 60 days of September 15, 2004, through the exercise of stock options.

(3) Ms. Heeg's stock ownership is as of December 31, 2003, when Ms. Heeg left the company.

(4) Mr. Kuehn's beneficial ownership excludes 27,720 shares of El Paso common stock owned by his wife or children, of which Mr. Kuehn disclaims any beneficial ownership.

(5) Mr. Wise's stock ownership is as of March 12, 2003 when Mr. Wise left El Paso. Mr. Wise's beneficial ownership excludes 400 shares of El Paso common stock owned by his children under the Uniform Gifts to Minors Act, of which Mr. Wise disclaims any beneficial ownership.

(6) Includes 98,000 stock options held in the William & Marie Wise Family Ltd. Partnership.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

We are currently a wholly owned subsidiary of El Paso. El Paso owns 100% of our outstanding stock and has the right to elect all of our directors. We share office space, personnel, and other administrative services with El Paso. In addition, there are other shared personnel that may include officers who function as both our representative and those of El Paso and its subsidiaries. Some of these shared directors, officers and employees own and are awarded from time to time shares, or options to purchase shares, of El Paso; accordingly, their financial interests may not always be aligned completely with ours.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees

The Audit Fees for the years ended December 31, 2003 and 2002 of $300,000 and $250,000 were for professional services rendered by PricewaterhouseCoopers LLP for the audits of the consolidated financial statements of El Paso CGP Company.

All Other Fees

No other audit-related, tax or other services were provided by our auditors for the years ended December 31, 2003 and 2002.

Policy for Approval of Audit and Non-Audit Fees

We are a wholly owned direct subsidiary of El Paso and do not have a separate audit committee. El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. For a description of El Paso's pre-approval policies for audit and non-audit related services, see El Paso Corporation's 2004 proxy statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

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

1. Financial statements.

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

El Paso CGP COMPANY

EXHIBIT LIST

December 31, 2003

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 "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
10.A	$3,000,000,00 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.1 to El Paso Corporation's Form 8-K filed April 18, 2003).
*10.A.1	First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 17, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lender and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents.
*10.A.2	Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents.
*10.A.3	Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 99.B to our Form 8-K filed August 10, 2004).

Exhibit Number	Description
10.B	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to El Paso Corporation's 2003 Second Quarter Form 10-Q).
*10.C	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement.
*21.	Subsidiaries of El Paso CGP Company.
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.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.
*32.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.

(b) Reports on Form 8-K

February 2, 2004	El Paso Corporation, our parent company, provided an update on our Production segment operations, which includes our production operations (includes information furnished under Item 9).
February 17, 2004	El Paso Corporation, our parent company, announced that it had completed its annual review of natural gas and oil reserve estimates. El Paso provided its proved reserve estimate and production update (which included ours).
March 10, 2004	El Paso Corporation, our parent company, announced that it would delay the release of its fourth quarter 2003 earnings pending the completion of a review of the impact of its recently announced reserve revision.
May 3, 2004	El Paso Corporation, our parent company, announced findings of an independent review of the Audit Committee of its Board of Directors concerning the revisions to its oil and natural gas reserves (including our reserves).

May 28, 2004	El Paso Corporation, our parent company, issued a press release providing a progress report on its long-range plan, financial and operational information for the fourth quarter of 2003 and the first quarter of 2004, and an update on the filing of El Paso Corporation, El Paso Production Holding Company, and our 2003 Form 10-K and the first quarter 2004 Form 10-Q (includes information furnished under Item 12).
June 15, 2004	El Paso Corporation, our parent company, announced that the Master Settlement Agreement related to the western energy crisis became effective on June 11, 2004.
June 17, 2004	El Paso Corporation, our parent company, announced that it had received waivers on its $3 billion revolving credit facility and certain other financings.
June 22, 2004	El Paso Corporation, our parent company, announced that it had closed the sale of its interests in UCF for approximately $21 million.
June 29, 2004	El Paso Corporation, our parent company, provided an update on its strategy plan for its production business, which includes our business.
August 10, 2004	El Paso Corporation, our parent company, announced its anticipated timeline for the filing of its and our Annual Report on Form 10-K.

We also furnished information to the SEC in Item 9 (now Item 7.01) and Item 12 (now Item 2.02) Current Reports on Form 8-K. These Forms 8-K are not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 and are not subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso CGP Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 12 day of October 2004.

EL PASO CGP COMPANY
Registrant

/s/ DOUGLAS L. FOSHEE

Douglas L. Foshee
President and Chief Executive Officer

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

Signature	Title	Date
/s/ DOUGLAS L. FOSHEE (Douglas L. Foshee)	President, Chief Executive Officer, Chairman of the Board and Director (Principal Executive Officer)	October 12, 2004
/s/ D. DWIGHT SCOTT (D. Dwight Scott)	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	October 12, 2004
/s/ ROBERT W. BAKER (Robert W. Baker)	Executive Vice President, General Counsel and Director	October 12, 2004
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	October 12, 2004