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

Form 8-K

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

DATE OF REPORT
November 4, 2005

(DATE OF EARLIEST EVENT REPORTED:
November 4, 2005)

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

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**1-7176** *(Commission File Number)*	**74-1734212** *(I.R.S. Employer Identification No.)*
El Paso Building **1001 Louisiana Street** **Houston, Texas** *(Address of Principal Executive Offices)*		**77002** *(Zip Code)*

Registrant's telephone number, including area code:
(713) 420-2600

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2 b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4 (c))

ITEM 8.01. ***OTHER EVENTS***

During the second quarter 2005, El Paso Corporation's Board of Directors approved the sale of our south Louisiana gathering and processing assets in our Field Services segment. As a result of the Board's actions, we began reporting these operations as discontinued operations in our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005.

This Current Report on Form 8-K was prepared to provide revised financial information and a discussion of our business that presents these gathering and processing assets as discontinued operations for all periods presented in our Annual Report on Form 10-K/A for the year ended December 31, 2004. It should be noted that our net income was not impacted by the reclassification of the south Louisiana gathering and processing assets. We have not otherwise updated our financial information or business discussion for activities or events occuring after the date this information was presented in our 2004 Form 10-K/A. You should read our Quarterly Report on Form 10-Q for the period ended June 30, 2005, for updating information.

This filing includes updated information for the following items included in our 2004 Form 10-K/A:

- Items 1. and 2. Business and Properties;

- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Risk Factors and Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995, and

- Item 8. Financial Statements and Supplementary Data.

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

/d	=	per day
Bbl	=	barrels
BBtu	=	billion British thermal units
BBtue	=	billion British thermal unit equivalents
Bcf	=	billion cubic feet
Bcfe	=	billion cubic feet of natural gas equivalents
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
Mcfe	=	thousand cubic feet of natural gas equivalents
MDth	=	thousand dekatherms
Mgal	=	thousand gallons
MMBtu	=	million British thermal units
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
MW	=	megawatt
TBtu	=	trillion British thermal units

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

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

BUSINESS AND PROPERTIES

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.

A description of our properties is included below. 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.

Business Segments

For the year ended December 31, 2004, we had both regulated and non-regulated operations conducted through four business segments — Pipelines, Production, Power and Field Services. Through these segments, we provided the following energy related services:

Regulated Operations	
Pipelines	We own or have interests in approximately 17,600 miles of pipeline and approximately 270 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.
Non-regulated Operations	
Production	We have interests in approximately 1.4 million net developed and undeveloped acres and had approximately 800 Bcfe of proved natural gas and oil reserves worldwide at the end of 2004. During 2004, our production averaged approximately 334 MMcfe/d.
Power	Our power business owns, manages or has an interest in approximately 3,700 MW of gross generating capacity in eight countries. Our plants serve customers under long-term and market-based contracts or sell to the open market in spot market transactions. We have completed the sale of substantially all of our domestic power operations and are evaluating potential opportunities to sell many of our remaining power assets.
Field Services	Our midstream or field services business provides processing and gathering services primarily in Texas and Utah.

We have discontinued operations related to a historical petroleum markets business, international natural gas and oil production operations, primarily in Canada, and our south Louisiana gathering and processing assets.

Below is a discussion of each of our business segments. Our business segments provide a variety of energy products and services. We manage each segment separately and each segment requires different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as, various other contracts and assets, all of which are immaterial. For additional discussion of our business segments, see our Management's Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and identifiable assets, see Financial Statements and Supplementary Data, Note 15, which is incorporated herein by reference.

Regulated Business — Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage and related services. We own or have interests in approximately 17,600 miles of interstate natural gas pipelines in the United States that connect the nation's principal natural gas supply regions to several large consuming regions in the United States. Our pipeline operations also include access to systems in Canada. We also own or have interests in approximately 270 Bcf of storage capacity used to provide a variety of flexible services to our customers.

Our Pipelines segment conducts its business activities primarily through four wholly owned and a partially owned interstate transmission system, 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, 2004			Average Throughput[1]		
		Miles of Pipeline	Design Capacity	Storage Capacity	2004	2003	2002
			(MMcf/d)	(Bcf)		(BBtu/d)	
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.	10,500	6,620	192	4,067	4,232	4,130
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	3,000	29	1,744	1,685	1,687
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,997	—	1,201	1,213	1,194
Cheyenne Plains Gas Pipeline (CPG)	Extends from the Cheyenne hub in Colorado to various pipeline interconnects near Greensburg, Kansas.	400	396[2]	—	89	—	—

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity was placed in service on December 1, 2004. Compression was added and placed in service on January 31, 2005, which increased the design capacity to 576 MMcf/d.

We also have several pipeline expansion projects underway as of December 31, 2004 that have been approved by the Federal Energy Regulatory Commission (FERC), the more significant of which are presented below:

Transmission System	Project	Capacity	Description	Anticipated Completion Date
		(MMcf/d)		
ANR	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[1] on the Denmark Lateral in Brown County, and modify ANR's existing Mountain Compressor Station in Oconto County, Wisconsin.	November 2005
	NorthLeg Wisconsin expansion	110	To add 6,000 horsepower of electric powered compression at ANR's Weyauwega Compressor station in Waupaca County, Wisconsin.	November 2005
CPG	Cheyenne Plains expansion	179	To add approximately 10,300 horsepower of compression and an additional treatment facility 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 a transmission system's capacity.

Partially Owned Interstate Transmission System

Transmission System	Supply and Market Region	As of December 31, 2004 Ownership Interest (Percent)	Miles of Pipeline[2]	Design Capacity[2] (MMcf/d)	Average Throughput[2] 2004	2003 (BBtu/d)	2002
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	2,200	2,366	2,378

(1) This system is accounted for as an equity investment.

(2) Miles, volumes and average throughput represent the system's totals and are not adjusted for our ownership interest.

We also have a 50 percent interest in Wyco Development, L.L.C. 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 compression facilities on WIC's Medicine Bow Lateral. These facilities are leased to PSCo and WIC, respectively, under long-term leases.

Underground Natural Gas Storage Entities

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

Storage Entity	As of December 31, 2004 Ownership Interest (Percent)	Storage Capacity[1] (Bcf)	Location
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	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 were accounted for as equity investments as of December 31, 2004.

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 usage charges based on the volume of gas actually transported, stored, injected or withdrawn. In 2004, approximately 90 percent of our transportation service and storage revenues were attributable to reservation charges paid by firm customers. The remaining 10 percent of our revenues were variable. Due to our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial 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. We also experience volatility in our financial results when the amount of gas utilized in our operations differs from the amounts we receive for that purpose.

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 these 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.

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

Electric power generation is the fastest growing demand sector of the natural gas market. The growth and development of the electric power industry potentially benefits 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, the more effective use of surplus electric capacity and increased natural gas prices. The increase in natural gas prices, driven in part by increased demand from the power sector, has diminished the demand for gas in the industrial sector. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their creditworthiness.

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, and in certain regions, 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 faced by each of our wholly owned pipeline systems as of December 31, 2004:

Transmission System	Customer Information	Contract Information	Competition
ANR	Approximately 259 firm and interruptible customers Major Customer: We Energies (909 BBtu/d)	Approximately 570 firm contracts Weighted average remaining contract term of approximately three years. Contract terms expire in 2005-2010.	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. ANR also competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR's principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.
CIG	Approximately 112 firm and interruptible customers Major Customer: Public Service Company of Colorado (970 BBtu/d) (261 BBtu/d) (187 BBtu/d)	Approximately 191 firm contracts Weighted average remaining contract term of approximately five years. Contract term expires in 2007. Contract term expires in 2009-2014. Contract terms expire in 2006.	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.
WIC	Approximately 49 firm and interruptible customers Major Customers: Williams Power Company (303 BBtu/d) Colorado Interstate Gas Company (247 BBtu/d) Western Gas Resources (235 BBtu/d) Cantera Gas Company (226 BBtu/d)	Approximately 47 firm contracts Weighted average remaining contract term of approximately six years. Contract terms expire in 2008-2013. Contract terms expire in 2005-2016. Contract terms expire in 2007-2013. Contract terms expire in 2012-2013.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC's one Bcf/d 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.

Transmission System	Customer Information	Contract Information	Competition
CPG	Approximately 15 firm and interruptible customers.	Approximately 14 firm contracts Weighted average remaining contract term of approximately 10 years.	Cheyenne Plains competes directly with other interstate pipelines serving the Mid-continent region. Indirectly, Cheyenne Plains competes with other interstate pipelines that transport Rocky Mountain gas to other markets.
	Major Customers:		
	Oneok Energy Services Company L.P. (195 BBtu/d)	Contract term expires in 2015.	
	Anadarko Energy Service Company (100 BBtu/d)	Contract term expires in 2015.	
	Kerr McGee (83 BBtu/d)	Contract term expires in 2015.	

Non-Regulated Business — 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, in the United States and Brazil. In the United States, as of December 31, 2004, we controlled approximately one million net acres of leasehold acreage through our operations primarily in Texas, Utah, West Virginia and Wyoming, and through our offshore operations in federal and state waters in the Gulf of Mexico. During 2004, daily equivalent natural gas production averaged approximately 334 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2004, were approximately 800 Bcfe.

We will focus on developing production opportunities around our asset base in the United States and in Brazil. Our other international operations that are not part of our long-term strategy have been treated as discontinued operations as further discussed in Financial Statements and Supplementary Data, Note 2.

Our operations are divided into the following areas:

Area	Operating Regions
United States	
Onshore	Rocky Mountains (primarily in Utah)
Texas Gulf Coast	South Texas
Offshore	Gulf of Mexico (Texas and Louisiana)
Brazil	Camamu, Santos and Espirito Santo Basins

Natural Gas, Oil and Condensate and Natural Gas Liquids (NGL) Reserves

The tables below detail our proved reserves at December 31, 2004. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserved prepared by Ryder Scott was within one percent of our internally prepared estimates presented in these tables. 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. Ryder Scott was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our proved properties based on value. Our estimated net proved reserves as of December 31, 2004, and our 2004 production are as follows:

	Net Proved Reserves[1]					2004
	Natural Gas	Oil/Condensate	NGL	Total		Production
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(Percent)	(MMcfe)
United States						
Onshore	35,260	12,749	—	111,758	14	5,860
Texas Gulf Coast	376,517	2,780	8,369	443,405	55	85,810
Offshore	99,757	3,830	230	124,122	15	30,426
Total United States	511,534	19,359	8,599	679,285	84	122,096
Brazil	—	20,795	—	124,772	16	—
Total	511,534	40,154	8,599	804,057	100	122,096

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

The table below summarizes our estimated net proved producing reserves, proved non-producing reserves, and proved undeveloped reserves as of December 31, 2004:

	Net Proved Reserves[1]				
	Natural Gas	Oil/Condensate	NGL	Total	
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(Percent)
United States					
Producing	326,723	8,612	7,310	422,256	62
Non-Producing	92,197	5,360	374	126,603	19
Undeveloped	92,614	5,387	915	130,426	19
Total proved	511,534	19,359	8,599	679,285	100
Brazil — undeveloped	—	20,795	—	124,772	100
Worldwide					
Producing	326,723	8,612	7,310	422,256	52
Non-Producing	92,197	5,360	374	126,603	16
Undeveloped	92,614	26,182	915	255,198	32
Total proved	511,534	40,154	8,599	804,057	100

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

Recovery of proved 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 proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the 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. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. 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. For further discussion of our reserves, see Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreage and Wells

The following table details our gross and net interest in developed and undeveloped acreage at December 31, 2004. 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)
United States						
Onshore	190,779	138,732	396,024	288,965	586,803	427,697
Texas Gulf Coast	115,876	76,193	220,806	163,236	336,682	239,429
Offshore	296,879	196,640	95,437	86,961	392,316	283,601
Total United States	603,534	411,565	712,267	539,162	1,315,801	950,727
Brazil	—	—	1,346,919	452,552	1,346,919	452,552
Total	603,534	411,565	2,059,186	991,714	2,662,720	1,403,279

(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.

Our United States net developed acreage is concentrated primarily in the Gulf of Mexico (48 percent), Utah (32 percent), and Texas (20 percent). Our United States net undeveloped acreage is concentrated primarily in Texas (31 percent), West Virginia (24 percent), Wyoming (20 percent), and the Gulf of Mexico (16 percent). Approximately 27 percent, 14 percent and 4 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2005, 2006 and 2007.

The following table details our working interests in natural gas and oil wells in the United States at December 31, 2004:

	Productive Natural Gas Wells		Productive Oil Wells[3]		Total Productive Wells		Number of Wells Being Drilled	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Onshore	35	6	287	217	322	223	—	—
Texas Gulf Coast	711	580	2	1	713	581	5	4
Offshore	155	120	34	27	189	147	2	—
Total	901	706	323	245	1,224	951	7	4

(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) Excludes two wells in Brazil that are not currently producing due primarily to regional infrastructure constraints.

We operated 922 of the 951 net productive wells as of December 31, 2004.

The following table details our exploratory and development wells drilled during the years 2002 through 2004:

	Net Exploratory Wells Drilled[1]			Net Development Wells Drilled[1]		
	2004	2003	2002	2004	2003	2002
United States						
Productive	12	19	18	10	53	166
Dry	3	9	8	1	1	1
Total	15	28	26	11	54	167
Brazil						
Productive	—	2	—	—	—	—
Dry	1	4	—	—	—	—
Total	1	6	—	—	—	—
Worldwide						
Productive	12	21	18	10	53	166
Dry	4	13	8	1	1	1
Total	16	34	26	11	54	167

(1) Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.

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 and average production costs associated with the sale of natural gas and oil for each of the three years ended December 31:

	2004	2003	2002
Net Production Volumes			
Natural gas (MMcf)	95,641	141,024	246,908
Oil, condensate and NGL (MBbls)	4,410	5,972	6,929
Total (MMcfe)	122,096	176,854	288,481
Natural Gas Average Realized Sales Price ($/Mcf)(1)			
Price, excluding hedges	$ 6.02	$ 5.43	$ 3.15
Price, including hedges(2)	$ 5.57	$ 4.72	$ 4.22
Oil, Condensate, and NGL Average Realized Sales Price ($/Bbl)(1)			
Price, excluding hedges	$ 35.24	$ 25.25	$ 20.08
Price, including hedges(2)	$ 35.24	$ 25.25	$ 20.12
Average Transportation Cost			
Natural gas ($/Mcf)	$ 0.11	$ 0.15	$ 0.15
Oil, condensate and NGL ($/Bbl)	$ 1.07	$ 0.89	$ 0.66
Average Production Cost ($/Mcfe)(3)			
Average lease operating cost	$ 0.75	$ 0.47	$ 0.49
Average production taxes	0.12	0.17	0.08
Total production cost	$ 0.87	$ 0.64	$ 0.57

(1) Prices are stated before transportation costs.

(2) Our hedging activities are conducted with our affiliate, El Paso Marketing.

(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:

	2004	2003	2002
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 6	$ —	$ 23
Unproved	4	9	12
Development Costs	150	270	569
Exploration Costs:			
Delay Rentals	3	4	4
Seismic Acquisition and Reprocessing	—	1	2
Drilling	84	211	191
Asset Retirement Obligations[1]	11	77	—
Total full cost pool expenditures	258	572	801
Non-full cost pool expenditures	3	4	18
Total capital expenditures	$261	$576	$819
Brazil			
Acquisition Costs:			
Unproved	$ 3	$ 4	$ 9
Development Costs	1	—	—
Exploration Costs:			
Seismic Acquisition and Reprocessing	14	11	32
Drilling	10	84	13
Total full cost pool expenditures	28	99	54
Non-full cost pool expenditures	2	1	2
Total capital expenditures	$ 30	$100	$ 56
Worldwide			
Acquisition Costs:			
Proved	$ 6	$ —	$ 23
Unproved	7	13	21
Development Costs	151	270	569
Exploration Costs:			
Delay Rentals	3	4	4
Seismic Acquisition and Reprocessing	14	12	34
Drilling	94	295	204
Asset Retirement Obligations[1]	11	77	—
Total full cost pool expenditures	286	671	855
Non-full cost pool expenditures	5	5	20
Total capital expenditures	$291	$676	$875

(1) Includes an increase to our property, plant and equipment of approximately $71 million in 2003 associated with our adoption of Statement of Financial Accounting Standards No. 143.

We spent approximately $11 million in 2004, $50 million in 2003 and $88 million in 2002 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

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 in which 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, water disposal rights, 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, El Paso maintains insurance on our behalf to limit exposure to potential losses from 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 property or injuries to people. 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 to limit exposure to potential losses resulting from these operating hazards.

Markets and Competition

We primarily sell our natural gas and oil to third parties through our affiliates 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 Marketing 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 operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and our ability to access drilling and other equipment on a timely and cost effective basis. 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.

Non-regulated Business — Power Segment

Our Power segment includes the ownership and operation of international and domestic power generation facilities as well as the management of restructured power contracts. As of December 31, 2004, we owned or had interests in 17 power facilities in eight countries with a total generating capacity of approximately 3,700 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. However, during 2004 and through the first quarter of 2005, we sold substantially all of our domestic power operations. We will continue to evaluate potential opportunities to sell or otherwise divest many of our remaining power assets.

International Power. As of December 31, 2004, we owned or had a direct investment in the following international power plants:

Project	Country	Ownership Interest[1] (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Asia						
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna	Bangladesh	74	113	Bangladesh Power	2013	Oil
Nanjing	China	80	75	Jiangsu Power	2017	Diesel
Saba	Pakistan	94	128	Pakistan Water and Power	2029	Oil
Suzhou	China	60	109	Jiangsu Power	2016	Natural Gas
Wuxi	China	60	39	Jiangsu Power	2010	Natural Gas
Central America						
CEPP	Dominican Republic	48	67	CDEEE, Spot Market	2014	Oil
Fortuna	Panama	25	300	Union Fenosa	2005, 2008	Hydroelectric
GEOSA	Nicaragua	26	115	Union Fenosa, Spot Market	2005, 2008	Oil
Itabo	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Nejapa[1]	El Salvador	87	144	AES and PPL	2005	Oil
Pedregal	Panama	21	50	Union Fenosa	2005	Oil
Tipitapa	Nicaragua	60	51	Union Fenosa	2014	Oil

(1) Our Nejapa power facility is consolidated in our financial statements. Our interests in all other international power facilities are reflected as investments in unconsolidated affiliates in our financial statements.

Domestic Power Plants. During 2004 and the first quarter of 2005, we sold substantially all of our domestic power assets. As of December 31, 2004, we owned or had a direct investment in the following domestic power facilities:

Project	State	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Midland Cogeneration[1]	MI	44	1,575	Consumers Power, Dow	2025	Natural Gas
CDECCA[3][2]	CT	50	62			Natural Gas
Eagle Point[4][2]	NJ	84	233			Natural Gas
Rensselaer[4][2]	NY	100	86			Natural Gas

(1) This power facility is reflected as an investment in unconsolidated affiliates in our financial statements.
(2) These power facilities (referred to as merchant plants) do not have long-term power purchase agreements with third parties. El Paso Marketing sells the power that a majority of these facilities generate to the wholesale power market.
(3) This plant has Board approval for sale and is targeted to be sold in the first half of 2005.
(4) These plants were sold in the first quarter of 2005.

Regulatory Environment & Markets and Competition

International. Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of these countries have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures are subject to change (including differing interpretations) over time.

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, competitive and political risks.

Domestic. 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. Our cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act of 1987 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.

Non-regulated Business — Field Services Segment

Our Field Services segment has historically conducted our midstream activities. In 2004, these activities were primarily in the south Louisiana production area. During the second quarter of 2005, El Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. These south Louisiana assets have been reclassified as discontinued operations for all periods presented.

Gathering and Processing Assets. As of December 31, 2004, our gathering systems consisted of 77 miles of pipeline with 25 MMcfe/d of throughput capacity located in Texas and Utah. These systems had average throughput of 7 BBtue/d during 2004. Our processing facilities had operational capacity and volumes as follows:

	Inlet Capacity	Average Inlet Volume			Average Sales		
	December 31, 2004	2004	2003	2002	2004	2003	2002
	(MMcfe/d)		(BBtue/d)			(Mgal/d)	
Altamont	27	9	8	11	16	19	26
Bluebell	22	9	9	10	22	22	24
Other(1)	—	—	43	326	—	98	689
Totals	49	18	60	347	38	139	739

(1) Volumes are related to assets previously sold.

Regulatory Environment. Some of our operations, owned directly or through equity investments, are subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of our operations, owned directly or through equity investments, 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. 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. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling and production activity, customer service and access to favorable downstream markets.

Other Operations and Assets

We currently have a number of other assets and businesses that are either included as part of our corporate activities or as discontinued operations.

Corporate Activities

Our corporate operations include our general and administrative functions as well as our petroleum ship charter operations and various other contracts and assets, all of which were insignificant to our results in 2004.

Discontinued Operations

During the second quarter of 2005, El Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. Accordingly, these assets and the results of their operations have been reclassified as discontinued operations for all periods presented. We also have petroleum markets operations and international natural gas and oil production operations, primarily in Canada, reported as discontinued operations in our financial statements.

Environmental

A description of our environmental activities is included in Financial Statements and Supplementary Data, Note 13 and is incorporated herein by reference.

Employees

As of April 5, 2005, we had approximately 900 full-time employees, none of whom are subject to collective bargaining agreements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this section is presented in a reduced disclosure format permitted by General Instruction I to Annual Report on Form 10-K. The Notes to Consolidated Financial Statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies. Certain historical financial information in this section has been restated, as further described in Financial Statements and Supplementary Data, Note 1.

During the second quarter of 2005, E1 Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. These assets and the results of their operations have been reclassified as discontinued operations for all periods presented.

Liquidity and Capital Resources

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.

Some of our subsidiaries are subsidiary guarantors of El Paso's $3 billion credit agreement. In connection with these guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the $3 billion credit agreement. Our ownership in the above mentioned companies is subject to change if there is an event of default under the $3 billion credit agreement and the lenders under the $3 billion credit agreement 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 could 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 some of 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 could adversely affect our liquidity position and, in turn, our financial condition.

For a further discussion of our debt, other obligations and other commitments and obligations, see Financial Statements and Supplementary Data, Notes 12 and 13.

Results of Operations

Overview

As of December 31, 2004, our operating business segments were Pipelines, Production, Power and Field Services. These segments provide a variety of energy products and services. They are managed separately and each requires different technology and marketing strategies. Our businesses are divided into two primary business lines: regulated and non-regulated. Our regulated business includes our Pipelines segment, while our non-regulated business includes our Production, Power and Field Services segments.

We use earnings before interest expense 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, which includes interest and debt expense and affiliated interest expense, and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of all of our businesses and investments. Also, we exclude interest and distributions on preferred interests of consolidated subsidiaries from this measure so that investors may evaluate our operating results without regard to our financing methods or capital structure. 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 EBIT (by segment) to our consolidated net loss for each of the years ended December 31:

	2004 (Restated)[1]	2003 (Restated)[1]
	(In millions)	
Regulated Business		
Pipelines	$ 434	$ 500
Non-regulated Businesses		
Production	171	219
Power	(349)	39
Field Services	18	(58)
Segment EBIT	274	700
Corporate	—	1
Consolidated EBIT	274	701
Interest and debt expense	(341)	(407)
Affiliated interest expense, net	—	(41)
Distributions on preferred interests of consolidated subsidiaries	—	(17)
Income taxes	5	(40)
Income (loss) from continuing operations	(62)	196
Discontinued operations, net of income taxes	(94)	(1,283)
Cumulative effect of accounting changes, net of income taxes	—	(12)
Net loss	$(156)	$(1,099)

(1) See Financial Statements and Supplementary Data, Note 1 for a discussion of the restatements of our 2004 and 2003 financial statements. The restatement of our 2004 financial statements affected the amount of losses in, and recorded on, our discontinued operations. The restatement of our 2003 financial statements affected the amount of income taxes recorded in discontinued operations related to our Canadian exploration and production operations.

Individual Segment Results

Regulated Business — Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage and related services in the United States. We face varying degrees of competition in this segment from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the cost 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, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather. In 2004, approximately 90 percent of our transportation service and storage revenues were attributable to reservation charges paid by firm customers. The remaining

10 percent of our revenues were variable. We also experience earnings volatility when the amount of natural gas utilized in operations differs from the amounts we receive for that purpose.

Historically, much of our business was conducted through long term contracts with customers. However, over the past several years 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, which can increase the volatility of our revenues, 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 power plant markets.

In addition, our ability to extend existing customer contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or 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. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately 4 years as of December 31, 2004. Below is the expiration schedule for contracts executed as of December 31, 2004, including those whose terms begin in 2005 or later.

	MDth/d	Percent of Total Contracted Capacity
2005	1,912	14
2006	2,581	19
2007	2,133	16
2008 and beyond	7,016	51

Operating Results

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

Pipelines Segment Results	2004	2003
	(In millions, except volume amounts)	
Operating revenues	$ 858	$ 918
Operating expenses	(508)	(521)
Operating income	350	397
Other income	84	103
EBIT	$ 434	$ 500
Throughput volumes (BBtu/d)(1)	7,962	8,158

(1) Throughput volumes exclude intrasegment activities.

The following contributed to our overall EBIT decrease in 2004 as compared to 2003:

	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Contract modifications/terminations	$(68)	$ 37	$ —	$(31)
Gas not used in operations, processing revenues and other natural gas sales	26	(14)	—	12
Other regulatory matters	—	(9)	(19)	(28)
Equity earnings from Great Lakes	—	—	8	8
Other[(1)]	(18)	(1)	(8)	(27)
Total impact on EBIT	$(60)	$ 13	$(19)	$(66)

(1) Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Contract Modifications/Terminations. Included in this item are (i) the renegotiation or restructuring of several contracts on our pipeline systems, including ANR's contracts with We Energies which contributed to the decrease in revenues by $36 million in 2004 and (ii) the termination of the Dakota gasification facility contract on ANR's system, which resulted in lower operating revenues and lower operating expenses during 2004, without a significant overall impact on operating income and EBIT.

Guardian Pipeline, which is owned in part by We Energies, currently provides a portion of We Energies' firm transportation requirements and, therefore, directly competes with ANR for a portion of the markets in Wisconsin. This could impact ANR's existing customer contracts as well as future contractual negotiations with We Energies. In addition, ANR has entered into an agreement with a shipper to restructure one of its transportation contracts on its Southeast Leg as well as a related gathering contract. In March 2005, this restructuring was completed and ANR received approximately $26 million, which will be included in its earnings during the first quarter of 2005.

Gas not used in Operations, Processing Revenues and Other Gas Sales. The financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to our tariff, relative to the amounts of gas we use for operating purposes, and the price of natural gas. Gas not needed for operations results in revenues to us, which is driven by volumes and prices during the period. During 2004, we recovered, fairly consistently, volumes of natural gas that were not utilized for operations. These recoveries were and are based on factors such as system throughput, facility enhancements, gas processing margins and the ability to operate the systems in the most efficient and safe manner. Additionally, a steadily increasing natural gas price environment during this timeframe also resulted in favorable impacts on our operating results in 2004 versus 2003. We anticipate that this area of our business will continue to vary in the future and will be impacted by things such as rate actions, efficiency of our pipeline operations, natural gas prices and other factors.

Expansions. During the two years ended December 31, 2004, we completed a number of expansion projects that have generated or will generate new sources of revenues, the more significant of which was our ANR WestLeg Expansion. Our expansions during these years added approximately 310 MMcf/d to our overall pipeline system.

Our pipeline systems connect the principal gas supply regions to the largest consuming regions in the U.S. We are well-positioned to capture growth opportunities in the Rocky Mountains and deepwater Gulf of Mexico, and have an infrastructure that complements LNG growth. We are aggressively seeking to attach new supplies of natural gas to our systems in order to maintain an adequate supply of gas to serve our growing markets and to replace quantities lost due to the natural decline in production from wells currently attached to our system.

Expansion projects currently in process include:

Rocky Mountain expansions. In order to provide an outlet for the growing supply of Rocky Mountain natural gas to markets in the Midwest region of the United States, we have several expansion projects that will increase our transportation capacity, subject to regulatory approval, as follows:

- Cheyenne Plains Gas Pipeline commenced free-flow operations in December 2004 and as of January 31, 2005 is fully in-service. Approval has already been received for Cheyenne Plains Phase II which will add an additional 179 MMcf/d of capacity that is scheduled to be available by the end of 2005.

- CIG's Raton Basin 2005 Expansion will add 104 MMcf/d of capacity that is scheduled to be available by the end of 2005.

- WIC expects to complete its Piceance lateral with capacity of 333 MMcf/d by the end of 2005.

Other expansions. On our ANR system we continue to experience intense competition along its mainline corridors; however, it is well-positioned to provide transportation service from discoveries in the deepwater Gulf of Mexico and LNG supply growth along the Gulf Coast. These new supplies are expected to offset the continued decline of production from the Gulf of Mexico shelf. Additionally, ANR is proceeding with its Eastleg and Northleg expansions in its Wisconsin market area.

Other Regulatory Matters. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $6 million to $12 million annually over the next eight years.

In 2003 we re-applied Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, on our CIG and WIC systems, resulting in income from recording the regulatory assets of these systems. SFAS No. 71 allows a company to capitalize items that will be considered in future rate proceedings and $18 million in 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 resulted in an increase in depreciation expense of approximately $9 million in 2004, an increase which will continue in the future. As of December 31, 2004, ANR Storage Company re-applied SFAS No. 71 which had an immaterial impact and also adopted the FERC depreciation rate which will result in future depreciation expense increases of approximately $4 million annually.

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability. CIG is required to file for new rates that would be effective October 2006. Our other pipelines have no requirements to file new rate cases and, absent any further regulatory action, expect to continue operating under their existing rates.

Non-regulated Businesses — Production Segment

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, sell the products at attractive prices and minimize our total administrative costs.

Our long-term strategy includes developing our production opportunities primarily in the United States and Brazil, while prudently divesting of production properties outside of these regions. We emphasize strict capital discipline designed to improve capital efficiencies through the use of standardized risk analysis and a heightened focus on cost control. We also implemented a more rigorous process for booking proved natural gas and oil reserves, which includes multiple layers of reviews by personnel independent of the reserve estimation process. Our plan is to stabilize production by improving the production mix across our operating areas and to generate more predictable returns. We intend to improve our production mix by allocating more capital to long-life, slower decline projects and to develop projects in longer reserve life areas. This is being accomplished through our more rigorous capital review process and a more balanced allocation of our capital to development and exploration projects, supplemented by acquisition activities with low-risk development locations that provide operating synergies with our existing operations. In March 2005, we purchased the interests held by one of the parties under a net profits interest agreement for approximately $22 million. See Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations for a further discussion of our net profits interest agreements.

Reserves, Production and Costs

Our estimate of proved natural gas and oil reserves as of December 31, 2004, reflects 679 Bcfe of proved reserves in the United States and 125 Bcfe of proved reserves in Brazil. These estimates were prepared internally by us. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserves prepared by Ryder Scott is within one percent of our internally prepared estimates. Ryder Scott was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our properties based on value. For additional information on our estimated proved reserves and the processes by which they are developed, see Business and Properties, Non-regulated Business — Production Segment in this Current Report on Form 8-K, as well as our Risk Factors, and Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

For 2004, our total equivalent production declined 55 Bcfe or 31 percent as compared to 2003. The decrease was due to production declines in our Texas Gulf Coast and offshore Gulf of Mexico regions and a significantly reduced capital expenditure program in 2004 compared to 2003.

Our depletion rate is determined under the full cost method of accounting. Due to disappointing drilling performance in 2004 that resulted in higher finding and development costs, we expect our domestic unit of production depletion rate to increase from $2.68/Mcfe in the fourth quarter of 2004 to $2.73/Mcfe in the first quarter of 2005. Our future trends in production and depletion rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sale or acquisition activities relating to our proved reserves.

Our relatively high historical finding and development costs and disappointing drilling performance increase the likelihood of future ceiling test charges if natural gas and oil prices decline or if we experience negative reserve revisions.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment programs. We conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production. Because this hedging strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. At December 31, 2004, our hedging position included 12,750 BBtu of our anticipated natural gas production for each quarter in 2005 at a hedged price of $3.31 per MMBtu.

In December 2004, we replaced our existing hedges on approximately 51 TBtu of natural gas with new hedge transactions at the same volume and over the same time period. The combination of our original hedges and the new transactions will not change the average price at which we are hedged and will not have an impact on our realized prices. As a result, these transactions will have the same impact on our accumulated other comprehensive income balances, cash flow and income statements as our original derivative positions that existed prior to December 1, 2004. However, these transactions "locked in" a loss of approximately $180 million in accumulated other comprehensive income that will be recognized in earnings as our original hedged transactions settle in 2005. We have entered into a service agreement with El Paso that provides for a reimbursement of 2.5 cents per MMBtu in 2005 for our expected administrative costs associated with these transactions.

Operational Factors Affecting the Year Ended December 31, 2004

During 2004, our Production segment experienced the following:

- *Higher realized prices.* Realized natural gas prices, which include the impact of our hedges, increased 18 percent and oil, condensate and NGL prices increased 40 percent compared to 2003.
- *Average daily production.* During 2004, our average daily production was 334 MMcfe/d (excluding discontinued Canadian and other international operations of 15 MMcfe/d).
- *Capital expenditures of $291 million (excluding discontinued Canadian and other international expenditures of $29 million).* During the first quarter of 2004, we experienced disappointing drilling results. As a result, we significantly reduced our drilling activities and instituted a new, more rigorous, risk analysis program, with an emphasis on strict capital discipline. During 2004, we drilled 27 wells with an 81 percent success rate.
- *Sale of Canadian and other international operations.* These operations were sold in order to focus our operations in the United States and Brazil.

Operating Results

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

Production Segment Results	**2004**	**2003**
	(In millions)	
Operating revenues:		
Natural gas	$ 533	$ 666
Oil, condensate and NGL	155	151
Other	2	5
Total operating revenues	690	822
Transportation and net product costs	(15)	(30)
Total operating margin	675	792
Depreciation, depletion and amortization	(315)	(347)
Production costs[(1)]	(107)	(114)
Ceiling test and other charges[(2)]	—	(44)
General and administrative expenses	(80)	(80)
Taxes, other than production and income taxes	1	—
Total operating expenses[(3)]	(501)	(585)
Operating income	174	207
Other income (expense)	(3)	12
EBIT	$ 171	$ 219

(1) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).
(2) Includes ceiling test charges, asset impairments and gains on asset sales.
(3) Transportation costs are included in operating expenses on our consolidated statements of income.

	2004	Percent Variance	2003
Volumes, prices and cost per unit:			
Natural gas			
Volumes (MMcf)	95,641	(32)%	141,024
Average realized prices including hedges ($/Mcf)[(1)]	$ 5.57	18%	$ 4.72
Average realized prices excluding hedges ($/Mcf)[(1)]	$ 6.02	11%	$ 5.43
Average transportation costs ($/Mcf)	$ 0.11	(27)%	$ 0.15
Oil, condensate and NGL			
Volumes (MBbls)	4,410	(26)%	5,972
Average realized prices including hedges ($/Bbl)[(1)]	$ 35.24	40%	$ 25.25
Average realized prices excluding hedges ($/Bbl)[(1)]	$ 35.24	40%	$ 25.25
Average transportation costs ($/Bbl)	$ 1.07	20%	$ 0.89
Total equivalent volumes (MMcfe)	122,096	(31)%	176,854
Production cost ($/Mcfe)			
Average lease operating cost	$ 0.75	60%	$ 0.47
Average production taxes	0.12	(29)%	0.17
Total production cost[(2)]	$ 0.87	36%	$ 0.64
Average general and administrative expenses ($/Mcfe)	$ 0.65	44%	$ 0.45
Unit of production depletion cost ($/Mcfe)	$ 2.42	32%	$ 1.84

(1) Prices are stated before transportation costs.
(2) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Our EBIT for 2004 decreased $48 million as compared to 2003. Despite an 18 percent increase in natural gas prices including hedges, we experienced a significant decrease in operating revenues due to lower production volumes as a result of production declines, asset sales, a lower capital spending program and disappointing drilling results. The table below lists the significant variances in our operating results in 2004 as compared to 2003:

	Variance		
	Operating Revenue	Operating Expense	EBIT Impact
	Favorable/(Unfavorable) (In millions)		
Natural Gas Revenue			
Higher prices in 2004	$ 56	$ —	$ 56
Lower production volumes in 2004	(247)	—	(247)
Impact from hedge program in 2004 versus 2003	58	—	58
Oil, Condensate, and NGL Revenue			
Higher realized prices in 2004	44	—	44
Lower production volumes in 2004	(40)	—	(40)
Depreciation, Depletion, and Amortization Expense			
Higher depletion rate in 2004	—	(71)	(71)
Lower production volumes in 2004	—	101	101
Production Costs			
Higher lease operating costs in 2004	—	(9)	(9)
Lower production taxes in 2004	—	16	16
Other			
Ceiling test and other charges in 2003	—	44	44
Other	(3)	3	—
Total variance 2004 to 2003	$(132)	$ 84	$ (48)

Operating Revenues. In 2004, we experienced a significant decrease in production volumes. The decline in our production volumes was due to production declines in the Offshore Gulf of Mexico and Texas Gulf Coast regions, asset sales in New Mexico in 2003, the impact of hurricanes in the Gulf of Mexico, significantly lower capital expenditures and disappointing drilling results. Partially offsetting the impact of lower production volumes were higher average realized prices for natural gas and oil, condensate and NGL and a favorable impact from our hedging program as our hedging losses were $43 million in 2004 as compared to $101 million in 2003.

Depreciation, depletion, and amortization expense. Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs.

Production costs. In 2004, we experienced higher workover costs due to the implementation of programs in the second half of 2004 to slow the production decline in the Offshore Gulf of Mexico and Texas Gulf Coast regions. More than offsetting these increases were lower production taxes as a result of lower production volumes and higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased due to lower production volumes and higher lease operating costs previously discussed.

Other. In 2003, we incurred ceiling test charges of $34 million related to our domestic full cost pool and $5 million associated with our full cost pool in Brazil. In addition, we recorded an impairment charge of $5 million, net of gains on asset sales, related to non-full cost pool assets. Included in the variance in other are general and administrative expenses that are allocated to the Production segment based on the relative contribution of its activities to El Paso's production activities as a whole, and not based solely on its production volumes. Our general and administrative expenses stayed relatively consistent from 2003 to 2004 as lower allocated costs were offset by a decrease in the costs we capitalized. However, our expense per Mcfe of production increased by 44 percent from 2003 to 2004 due primarily to the decrease in production volumes year-over-year.

Non-regulated Business — Power Segment

As of December 31, 2004, our Power segment consists of our Asian power assets, our investment in the Midland Cogeneration Venture (MCV) domestic power facility, and other power businesses, primarily equity investments in Central America. Historically, this segment also included a domestic power contract restructuring business, which we sold in 2004. We have designated all of our power operations as non-core activities, and we continue to evaluate potential opportunities to sell or otherwise divest many of our remaining power assets. As this process progresses, we will continue to assess the value of these assets which may result in impairments.

Asia. Our Asian operations include equity investments in six power plants. These facilities sell electricity and electrical generating capacity under long-term power sales agreements with local transmission and distribution companies, many of which are government controlled. The majority of these contracts allow for changes in fuel costs to be passed through to the customer through power prices. The economic performance of these facilities is impacted by the level of electricity demand and changes in the political and regulatory environment in the countries they serve as well as the relative cost of producing that power. We recorded an impairment in 2004 in connection with our decision to sell these assets.

MCV. We have an equity ownership in a natural gas-fired power plant, MCV. The price of electricity sold by MCV is indexed to coal, while the plant is fueled by natural gas, which it purchases under both long-term contracts and on the spot market. Changes in the relationship between coal and natural gas prices directly impact the economic performance of this facility. In 2004, we recorded an impairment of our interest in this plant based on a decline in the value of the investment that we considered to be other than temporary.

Domestic Power Contract Restructuring Business. In 2002, we completed several contract restructuring transactions, the largest of which was Utility Contract Funding (UCF). During 2004, we completed the sale of all of the entities that hold our restructured power contracts.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the years ended December 31. Substantial changes in the business during these periods affected year-to-year comparability.

	2004	2003
	(In millions)	
Overall EBIT:		
Gross margin[1]	$ 100	$ 174
Operating expenses		
Loss on long lived assets	(102)	(28)
Other operating expenses	(95)	(124)
Operating income (loss)	(97)	22
Earnings from unconsolidated affiliates		
Impairments, net of gains on sale	(288)	(43)
Equity in earnings	15	37
Other income	21	23
EBIT	$(349)	$ 39
Significant factors impacting EBIT:		
Asia		
Earnings from plant operations	$ 13	$ 2
Impairment and write-off	(131)	—
MCV		
Earnings from plant operations	(10)	29
Impairment	(161)	—
Domestic power contract restructuring activities		
Increase in fair values	36	65
Impairments and gains (losses) on sale	(88)	7
Other power assets		
Earnings from consolidated and unconsolidated plant operations	2	14
Impairment and gain on sale of Bastrop equity investment	3	(43)
Other impairments, net of gains on sale	(13)	(35)
EBIT	$(349)	$ 39

(1) Gross margin for our Power segment consists of revenues from our power plants and revenues, cost of electricity purchases and changes in fair value of restructured power contracts. The cost of fuel used in the power generation process is included in operating expenses.

Asia. During the fourth quarter of 2004, we recorded a $131 million charge on our Asian power assets in connection with our decision to pursue the sale of these assets. These impairment amounts were based on our estimates of the fair value of these projects. In 2005, we engaged a financial advisor to assist us in the sale of these assets. As this process continues, we will continue to update the fair value of these assets, which may result in further impairments.

Our earnings from one of our equity investments in a power plant in Pakistan were $12 million lower in 2003 as compared to 2004 primarily due to expenses incurred by the plant in 2003 associated with the resolution of construction-related issues. From 2003 to 2004, earnings from our other Asian power assets were relatively stable as the underlying plants maintained steady levels of availability and production. Higher fuel costs during these periods did not materially impact these plants' operations as substantially all of the higher fuel costs were passed through to the power purchasers through higher contracted power prices.

MCV. Our MCV power plant is a natural gas-fired plant, which sells its power at a contracted price that is indexed to coal prices. During 2004, MCV experienced reduced EBIT primarily because natural gas prices increased at a faster rate than coal prices. This decrease in EBIT was magnified by an increase in the volume of power MCV was required to generate. In January 2005, MCV received regulatory approval to reduce the required level of power generation. In the fourth quarter of 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

Domestic Power Contract Restructuring Activities. We recorded impairments and gains (losses) on our interests in UCF and Mohawk River Funding IV related to the sale of these entities and their restructured power contracts in 2004 and 2003.

Other Power Assets. During 2003, we recorded an impairment of our Bastrop equity investment and two other consolidated power plants based on the anticipated sale of these assets.

As part of El Paso's long-term business strategy, we continue to evaluate potential opportunities to sell or otherwise divest of many of our remaining power assets. As these sales occur and/or as market indicators of fair value become available, it is possible that impairments of these assets may occur, which may be significant.

Non-regulated Businesses — Field Services Segment

Our Field Services segment has historically conducted our midstream activities through its portfolio of natural gas gathering and processing assets. We have sold a substantial portion of these assets in 2003 and 2004. During the second quarter of 2005, E1 Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. The south Louisiana gathering and processing assets and the results of these south Louisiana operations have been reclassified as discontinued operations for all periods presented. Field Services remaining assets provide gathering and processing services primarily in Texas and Utah

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

Field Services Segment Results	2004	2003
	(In millions)	
Gathering and processing gross margins[1]	$15	$ 24
Operating expenses		
Gain (loss) on long-lived assets	(5)	13
Other operating expenses	(3)	(2)
Operating income	7	35
Other income (expense)		
Equity earnings (impairments) and gains (losses) on sale of unconsolidated affiliates	11	(93)
EBIT	$18	$(58)

(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 segment's operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Below is a summary of significant factors and related discussions affecting EBIT for each of the years ended December 31:

	EBIT Impact	
	2004	2003
	(In millions)	
Gathering and processing margins	$ 15	$ 24
Operating expenses	(3)	(2)
Equity earnings (losses)	14	(7)
Asset impairments and gains (losses) on sales		
Mid-Continent	—	19
Dauphin Island/Mobile Bay	—	(86)
Other	(8)	(6)
EBIT	$ 18	$(58)

During 2004 and 2003 we sold a substantial amount of our assets. Listed below are the significant transactions:

- 2003 — Sale of our Wyoming gathering assets and Mid-Continent gathering and processing assets. In addition, we recorded an impairment of our investments in Dauphin Island and Mobile Bay based on the pending sale.
- 2004 — Sale of our investments in Dauphin Island and Mobile Bay.

Interest and Debt Expense

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

	2004	2003
Long-term debt, including current maturities	$353	$412
Other interest	2	6
Capitalized interest	(14)	(11)
Total interest and debt expense	$341	$407

Interest expense on long-term debt for the year ended December 31, 2004, was $59 million lower than in 2003 due primarily to the retirement of $1.9 billion of debt during 2003 and 2004, partially offset by interest on $300 million of borrowings by ANR in 2003 and interest on $300 million of Coastal Finance I preferred securities for a full year in 2004. In 2003, we reclassified the Coastal Finance I preferred securities from preferred interests of consolidated subsidiaries to long-term debt.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the year ended December 31, 2004, was $41 million lower than the same period in 2003, due to lower average balances partially offset by higher average short term interest rates for 2004. The average advance balances for the twelve months decreased from $2,052 million in 2003 to less than $24 million in 2004. The decrease in advances includes a $1,500 million contribution from El Paso Corporation. The average short-term interest rates increased from 2.0% in 2003 to 2.4% in 2004.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2004, were $17 million lower than in 2003, 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.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Financial Statements and Supplementary Data, Note 12.

Income Taxes

Income taxes for 2004 and 2003 have been revised to reflect the effects on income taxes of the restatements described in Financial Statements and Supplementary Data, Note 1. Income taxes for the years ended December 31, 2004 and 2003 were $(5) million and $40 million, resulting in effective tax rates of 7 percent and 17 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes, net of federal income tax effect;
- foreign income/loss taxed at different rates;
- abandonments and sales of foreign investments;
- valuation allowances;
- non-taxable stock dividends; and
- dispositions of domestic assets.

For 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to impairments of certain of our foreign investments for which there was no corresponding U.S. federal income tax benefit.

For 2003, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to $25 million of tax benefits related to abandonments and sales of certain of our foreign investments.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not provided U.S. deferred taxes on foreign earnings where such earnings were intended to be indefinitely reinvested outside the U.S. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

As part of our long-term business strategy, we anticipate that we will sell our Asian power investments. As further discussed in Financial Statements and Supplementary Data, Note 6, we have not historically recorded United States deferred taxes on book versus tax basis differences in these investments because our intent was to indefinitely reinvest earnings from these projects outside the United States. In 2004, our intent on these assets changed, and we now intend to use the proceeds from the sale within the U.S. As a result, we recorded U.S. deferred tax liabilities for those instances where the book basis in our investment exceeded the tax basis in 2004. At this time, however, due to uncertainties as to the manner, timing and approval of the anticipated sale transactions, we have not recorded U.S. deferred tax assets for those instances where the tax basis in our investment exceeded the book basis, except in instances where we believe the realization of the asset is assured. As these uncertainties become known, we will record additional tax effects to reflect the ultimate sale transactions, the amounts of which could have a significant impact on our future recorded tax amounts and our effective tax rates in those periods.

Discontinued Operations

Our loss from discontinued operations for 2004 and 2003 has been restated to adjust the amount of losses on sales of assets and investments and related tax adjustments in our discontinued Canadian exploration and production operations and petroleum market operations which had cumulative foreign currency translation adjustment (CTA) balances. For a further discussion see Financial Statements and Supplementary Data, Note 1.

In addition, during the second quarter of 2005, El Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. Accordingly, these assets and the results of their operations have been reclassified as discontinued operations for all periods presented. We also have petroleum markets operations and international natural gas and oil production operations that are classified as discontinued operations in our financial statements.

For the year ended December 31, 2004, the loss from our discontinued operations was $94 million compared to a loss of $1.3 billion during 2003. In 2004, $36 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from losses on sales and impairment charges and $79 million of losses was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. Partially offsetting these losses was $21 million of income from our south Louisiana processing assets. The losses in 2003 related primarily to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of El Paso's decision to exit and sell these businesses and ceiling test charges related to our Canadian production operations.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Financial Statements and Supplementary Data, Note 13, incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

See Financial Statements and Supplementary Data, Note 1 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 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 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:

- service area competition;
- expiration and/or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- future weather conditions;
- price competition;
- drilling activity and supply availability of natural gas;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- increased availability or popularity of alternative energy sources such as hydroelectric power;

- 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.

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 or LNG terminals 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, earnings and cash flows.

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. We also experience earnings volatility when the amount of gas utilized in operations differs from amounts we receive for that purpose. 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. We retain a fixed percentage of natural gas transported for use as fuel and to replace lost and unaccounted for gas, and we are at risk for the difference between the retained amount and actual gas consumed or lost and unaccounted. Pricing volatility may also impact the value of under or over recoveries of this retained gas. 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 could adversely affect the financial results of our exploration and production business.

Our future financial condition, revenues, results of operations, cash flows, and future rate of growth 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;
- the availability of pipeline capacity;
- 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 64 percent of our proved reserves at December 31, 2004 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.

Our use of hedging arrangements may adversely affect our future results of operations or liquidity.

To reduce our exposure to fluctuations in the prices of natural gas and oil, we may use futures, swaps and option contracts traded on the New York Mercantile Exchange (NYMEX), over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. We also enter into hedging arrangements with El Paso Marketing. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- expected production is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Our hedging arrangements may also limit the benefit we would receive from increases in the prices for natural gas and oil. The use of derivatives also may require the posting of cash collateral with counterparties which can impact working capital when commodity prices change. El Paso provides us with gas marketing and hedging services and we currently do not post cash collateral with counterparties. In addition, these hedging arrangements may impact the carrying value of our natural gas and oil properties in our full cost pool as we include hedges in our ceiling test calculation.

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;
- 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, or adverse court decisions 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; and
- 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 the United States. 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. New wells drilled by us may not be productive, 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 wells that are productive may 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.

Our reserve data represents an estimate. 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, 2004, 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 proved undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

The success of our power 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 United States 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 businesses are subject to the risk of payment defaults by our counterparties.

We frequently extend credit to our counterparties following the performance of credit analysis. Despite performing this analysis, we are exposed to the risk that we may not be able to collect amounts owed to us. Although in many cases we have collateral to secure the counterparty's performance, it could be inadequate and we could suffer credit losses.

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States 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.

Retained liabilities associated with businesses that we have sold could exceed our estimates.

We have sold a significant number of assets over the years, including the sale of many assets since 2001. Pursuant to various purchase and sale agreements relating to businesses and assets that we have divested, we have either retained certain liabilities or indemnified certain purchasers against liabilities that they might incur in the future. These liabilities in many cases relate to breaches of warranties, environmental, tax, litigation, personal injury and other representations that we have provided. Although we believe that we have established appropriate reserves for these liabilities, we could be required to accrue additional reserves in the future and these amounts could be material. In addition, as we exit businesses, we have experienced substantial reductions and turnover in our workforce that previously supported the ownership and operation of such assets. There is the risk that such reductions and turnover in our workforce could result in errors or mistakes in managing the businesses that we are exiting prior to closing. There is also the risk that such reductions could result in errors or mistakes in managing the retained liabilities after closing, including the lack of any historical knowledge with regard to such assets and businesses in managing the liabilities or defending any associated litigation.

Risks Related to Legal and Regulatory Matters

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

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves. As a result of this 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.

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. In setting authorized rates of return in a few recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risks as interstate pipelines. The inclusion of these companies creates downward pressure on approved tariff rates. 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.

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 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 pollution control and 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
- potential changes in environmental laws and regulations, including changes in the interpretation and enforcement thereof.

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 in our 2004 Annual Report on Form 10-K, as amended, and Financial Statements and Supplementary Data, Note 13.

Costs of litigation and other contingencies could exceed our estimates.

We are involved in various lawsuits in which we or our subsidiaries have been sued. We also have other contingent liabilities and exposures. 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, and the effect of adverse judgments on our operations could be material. For additional information concerning these matters, see Part I, Item 3, Legal Proceedings in our 2004 Annual Report on Form 10-K, as amended, and Financial Statements and Supplementary Data, Note 13.

Risks Related to Our Liquidity

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

We have significant debt of approximately $3.8 billion as of December 31, 2004 and have significant debt service and debt maturity obligations. Our expected debt maturities as of December 31, 2004 for 2005, 2006 and 2007 are $310 million, $330 million and $8 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 Financial Statements and Supplementary Data, Note 12, 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 borrow funds 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. Some of our subsidiaries have covenants which become more restrictive over time. A breach of certain of these covenants could preclude our subsidiaries from issuing letters of credit and from borrowing under El Paso's $3 billion credit agreement, and could accelerate our long-term debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

We are a wholly owned direct subsidiary of El Paso and its financial condition and business strategy 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 Investor Service (Moody's) and CCC+ by Standard & Poor's. Our senior unsecured indebtedness is rated Caa1 by Moody's and CCC+ by Standard & Poor's. 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 continues it efforts to execute its Long Range Plan that established certain financial and other objectives, including asset sales and significant debt reduction. 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, 2004, we have net payables of approximately $166 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 2005. 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 Financial Statements and Supplementary Data, Note 16.

Our system of internal controls are designed to ensure the accuracy and completeness of our disclosures and a loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.

We are required to maintain an effective system of internal control over financial reporting. As a result of our efforts to comply with this requirement, we determined that as of December 31, 2004, we did not maintain effective internal control over financial reporting. As more fully discussed in Item 7, Controls and Procedures in our 2004 Annual Report on Form 10-K, as amended, we identified several deficiencies in internal control over financial reporting that management has concluded constituted material weaknesses. Although we have taken steps to remediate some of these deficiencies, additional steps must be taken to remediate the remaining control deficiencies. If we are unable to remediate our identified internal control deficiencies over financial reporting, or we identify additional deficiencies in our internal controls over financial reporting, we could be subjected to additional regulatory scrutiny, future delays in filing our financial statements and suffer a loss of public confidence in the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, which could have a negative impact on our liquidity, access to capital markets, and our financial condition.

In addition to the risk of not completing the remediation of all deficiencies in our internal controls over financial reporting, we do not expect that our disclosure controls and procedures or our internal controls over financial reporting will prevent all mistakes, errors and fraud. Any system of internal controls, no matter how well designed or implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that the benefits of controls must be considered relative to their costs. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Therefore, any system of internal controls is subject to inherent limitations, including the possibility that controls may be circumvented or overridden, that judgments in decision-making can be faulty, and that misstatements due to mistakes, errors or fraud may occur and may not be detected. Also, while we document our assumptions and review financial disclosures, the regulations and literature governing our disclosures are complex and reasonable persons may disagree as to their application to a particular situation or set of facts. In addition, the applicable regulations and literature are relatively new. As a result, they are potentially subject to change in the future, which could include changes in the interpretation of the existing regulations and literature as well as the issuance of more detailed rules and procedures.

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 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 and liquidity, results of operations and cash flows.

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

Some of our subsidiaries are subsidiary guarantors of El Paso's $3 billion credit agreement. In connection with these guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the $3 billion credit agreement. Our ownership in the above mentioned companies is subject to change if there is an event of default under the $3 billion credit agreement and the lenders under this agreement exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition.

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.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following historical financial statements reflect the reclassification of our south Louisiana gathering and processing assets as discontinued operations for all periods presented.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2004 (Restated)	2003 (Restated)	2002
Operating revenues			
Pipelines	$ 858	$ 918	$ 934
Production	690	822	1,187
Power	149	252	1,216
Field Services	151	110	256
Corporate and eliminations	41	9	(12)
	1,889	2,111	3,581
Operating expenses			
Cost of products and services	321	354	932
Operation and maintenance	505	507	731
Depreciation, depletion and amortization	463	483	592
Ceiling test charges	—	39	422
Loss (gain) on long-lived assets	106	8	(12)
Taxes, other than income taxes	59	78	73
	1,454	1,469	2,738
Operating income	435	642	843
Earnings (losses) from unconsolidated affiliates	(193)	(12)	113
Other income	44	66	70
Other expenses	(12)	5	(70)
Interest and debt expense	(341)	(407)	(425)
Affiliated interest expense, net	—	(41)	(9)
Distributions on preferred interests of consolidated subsidiaries	—	(17)	(35)
Income (loss) before income taxes	(67)	236	487
Income taxes	(5)	40	136
Income (loss) from continuing operations	(62)	196	351
Discontinued operations, net of income taxes	(94)	(1,283)	(400)
Cumulative effect of accounting changes, net of income taxes	—	(12)	14
Net loss	$ (156)	$(1,099)	$ (35)

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)

	December 31, 2004 (Restated)	December 31, 2003 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ 80	$ 150
Accounts and notes receivable		
Customer, net of allowance of $27 in 2004 and $37 in 2003	217	244
Affiliates	264	442
Other	93	90
Inventory	52	52
Assets from price risk management activities	—	97
Assets held for sale and from discontinued operations	185	1,452
Deferred income taxes	87	31
Other	40	93
Total current assets	1,018	2,651
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,153	7,230
Pipelines	7,040	6,478
Power facilities	373	372
Gathering and processing systems	44	66
Other	89	119
	14,699	14,265
Less accumulated depreciation, depletion and amortization	7,981	7,991
Total property, plant and equipment, net	6,718	6,274
Other assets		
Investments in unconsolidated affiliates	894	1,312
Assets from price risk management activities	—	845
Goodwill and other intangible assets, net	419	415
Other	295	913
	1,608	3,485
Total assets	$ 9,344	$12,410

See accompanying notes.

EL PASO CGP COMPANY

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

	December 31,	
	2004 (Restated)	2003 (Restated)
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 153	$ 137
Affiliates	61	67
Other	211	198
Current maturities of long-term debt	310	310
Notes payable to affiliates	211	949
Liabilities from price risk management activities	148	43
Liabilities related to discontinued operations	104	764
Other	270	314
Total current liabilities	1,468	2,782
Long-term financing obligations, less current maturities	3,447	5,011
Other		
Liabilities from price risk management activities	—	81
Deferred income taxes	692	734
Other	388	351
	1,080	1,166
Commitments and contingencies		
Securities of subsidiaries	158	107
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	3,181	3,136
Retained earnings	103	259
Accumulated other comprehensive loss	(93)	(51)
Total stockholder's equity	3,191	3,344
Total liabilities and stockholder's equity	$9,344	$12,410

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2004[1] (Restated)	2003[1] (Restated)	2002
Cash flows from operating activities			
Net loss	$ (156)	$(1,099)	$ (35)
Less loss from discontinued operations, net of tax	(94)	(1,283)	(400)
Net income (loss) before discontinued operations	(62)	184	365
Adjustment to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion, and amortization	463	483	592
Ceiling test charges	—	39	422
Deferred income tax expense (benefit)	(56)	(40)	164
Loss (gain) on long-lived assets	106	8	(12)
Losses from unconsolidated affiliates, adjusted for cash distributions	299	103	28
Other non-cash items	12	6	34
Asset and liability changes			
Accounts and notes receivable	60	438	(483)
Inventory	—	9	47
Change in non-hedging price risk management activities, net	6	22	(480)
Accounts payable	12	(115)	(301)
Other asset and liability changes			
Assets	(19)	42	217
Liabilities	(34)	18	(114)
Cash provided by continuing operations	787	1,197	479
Cash provided by (used in) discontinued operations	223	(53)	(224)
Net cash provided by operating activities	1,010	1,144	255
Cash flows from investing activities			
Additions to property, plant, and equipment	(806)	(851)	(1,214)
Purchases of interests in equity investments	(12)	(4)	(45)
Net proceeds from the sale of assets and investments	87	313	1,638
Net change in restricted cash	21	(18)	(59)
Net change in notes receivable from affiliates	171	(109)	(102)
Other	48	(35)	(19)
Cash provided by (used in) continuing operations	(491)	(704)	199
Cash provided by (used in) discontinued operations	1,132	460	(296)
Net cash provided by (used in) investing activities	641	(244)	(97)

(1) Only individual line items within cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(In millions)

	Year Ended December 31,		
	2004[1] (Restated)	2003[1] (Restated)	2002
Cash flow from financing activities			
Net repayments under commercial paper and short-term credit facilities	—	—	(30)
Capital contribution from parent company	—	1,500	—
Net proceeds from the issuance of long-term debt and other financing obligations	—	288	882
Payments to retire long-term debt and other financing obligations	(692)	(638)	(1,240)
Payments to minority interest holders and preferred interests holders	—	(100)	(510)
Net change in notes payable to unconsolidated affiliates	—	(7)	(56)
Net change in affiliated advances payable	(738)	(1,404)	1,317
Dividends paid	—	(517)	—
Proceeds from issuance of securities of subsidiaries	75	—	33
Other	(2)	—	(6)
Contributions from (distributions to) discontinued operations	991	407	(1,081)
Cash used in continuing operations	(366)	(471)	(691)
Cash provided by (used in) discontinued operations	(1,355)	(407)	530
Net cash used in financing activities	(1,721)	(878)	(161)
Change in cash and cash equivalents	(70)	22	(3)
Less change in cash and cash equivalents related to discontinued operations	—	—	10
Change in cash and cash equivalents from continuing operations	(70)	22	(13)
Cash and cash equivalents			
Beginning of period	150	128	141
End of period	$ 80	$ 150	$ 128
Supplemental Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 369	$ 473	$ 438
Income tax payments (refunds)	49	91	(25)

(1) Only individual line items within cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In millions except share amounts)

	For the Years Ended December 31,					
	2004		2003		2002	
	Shares	Amount	Shares	Amount	Shares	Amount
	(Restated)		(Restated)			
Common stock, par value $1 per share, authorized 1,000 shares						
Balance at beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance at end of year	1,000	—	1,000	—	1,000	—
Additional paid-in capital						
Balance at beginning of year		3,136		1,616		1,305
Capital contribution from El Paso		45		1,524		309
Other		—		(4)		2
Balance at end of year		3,181		3,136		1,616
Retained earnings						
Balance at beginning of year		259		1,875		1,910
Net loss		(156)		(1,099)		(35)
Dividends to parent		—		(517)		—
Balance at end of year		103		259		1,875
Accumulated other comprehensive income (loss)						
Balance at beginning of year		(51)		(139)		283
Other comprehensive income (loss)		(42)		88		(422)
Balance at end of year		(93)		(51)		(139)
Total stockholder's equity		$3,191		$ 3,344		$3,352

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2004 (Restated)	2003 (Restated)	2002
Net loss	$(156)	$(1,099)	$ (35)
Foreign currency translation adjustments (net of income tax benefit of $36 in 2004 and income tax expense of $36 in 2003)	(33)	76	(14)
Minimum pension liability accrual (net of income tax of $2 in 2004, $1 in 2003 and $7 in 2002)	(3)	(5)	(12)
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market losses arising during period (net of income tax of $15 in 2004, $24 in 2003 and $140 in 2002)	(26)	(42)	(240)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $12 in 2004, $34 in 2003 and $87 in 2002)	20	59	(156)
Other comprehensive income (loss)	(42)	88	(422)
Comprehensive loss	$(198)	$(1,011)	$(457)

See accompanying notes.

1. Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned and/or controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for all periods presented reflect our south Louisiana gathering and processing assets, Canadian and certain other international natural gas and oil production operations, 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 loss or stockholder's equity.

Restatement

We determined that our CTA balances in accumulated other comprehensive loss incorrectly contained amounts related to businesses that had been previously sold or abandoned. These businesses included our discontinued Canadian exploration and production operations and certain of our discontinued petroleum markets activities. The adjustment of these CTA balances also affected the loss we recorded in 2004 on the sale of our Canadian operations.

In conjunction with the revisions for CTA, we also determined that upon initially recognizing deferred income taxes on our Canadian exploration and production operations, we did not properly allocate taxes to CTA in 2003. These allocated amounts then impacted the 2004 loss we recorded on the sale of our Canadian operations.

The overall impact of these adjustments for CTA and their related tax impact was a $32 million reduction in our net loss from discontinued operations in 2004. In 2003, the overall impact of these adjustments was a reduction in our net loss from discontinued operations of $35 million. As of December 31, 2004, the effect of these adjustments to total stockholders' equity was a $1 million decrease resulting from an increase in retained earnings of $67 million and an increase in accumulated other comprehensive loss of $68 million.

Below are the effects of the restatements related to income taxes and CTA on our income statements, balance sheets and statements of comprehensive income. We have reflected these restatements in Notes 2, 6, 8, and 15.

	For the Year Ended December 31,			
	2004		2003	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Income Statement:				
Discontinued operations, net of income taxes	$(126)	$ (94)	$(1,318)	$(1,283)
Net loss	(188)	(156)	(1,134)	(1,099)
Statement of Comprehensive Income				
Foreign currency translation adjustment	$ (1)	$ (33)	$ 112	$ 76
Other comprehensive income (loss)	(10)	(42)	124	88

	As of December 31,			
	2004		2003	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Balance Sheet:				
Deferred income tax assets, current	$ 87	$ 87	$ 30	$ 31
Deferred income tax liabilities, non-current	691	692	732	734
Retained earnings	36	103	224	259
Accumulated other comprehensive loss	(25)	(93)	(15)	(51)
Total stockholder's equity	3,192	3,191	3,345	3,344

Principles of Consolidation

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interests in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the decisions and policies of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity. For a further discussion of the implementation of an accounting standard that impacted our consolidation principles beginning January 1, 2004, see below.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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. Of our regulated pipelines, CIG, WIC and CPG follow the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* ANR and ANR Storage 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. Effective December 31, 2004, ANR Storage began re-applying the provisions of SFAS No. 71.

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, 2004 we had $11 million of restricted cash in other current assets and $18 million in other non-current assets. As of December 31, 2003, we had $36 million of restricted cash in other current assets and $43 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 natural gas and NGL in storage and materials and supplies. 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. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates. The following table presents our property, plant and equipment by type, depreciation method and depreciable lives:

Type	Method	Depreciable Lives (In years)
Regulated interstate systems		
SFAS No. 71	Composite[1]	1-51
Non-SFAS No. 71	Composite[1]	1-64
Non-regulated systems		
Transmission and storage facilities	Straight-line	35
Power facilities	Straight-line	3-22
Gathering and processing systems	Straight-line	3-33
Buildings and improvements	Straight-line	15-40
Office and miscellaneous equipment	Straight-line	3-10

(1) For our regulated interstate systems, 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, 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.

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 our debt that could be attributed to the assets, which applies to all our businesses and (ii) a return on our equity, that could be attributed to the assets, which only applies to regulated transmission businesses that apply SFAS No. 71. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized during the years ended December 31, 2004, 2003 and 2002, were $14 million, $11 million and $14 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 and Investment Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*, to account for asset and investment impairments. Under these standards, we evaluate an asset or investment for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investment in unconsolidated affiliates. If an impairment is indicated or if 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 their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or 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 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 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 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 greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, 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, goodwill and intangibles that have indefinite lives are not amortized, but instead are periodically tested for impairment, at least annually, and whenever an event occurs that indicates that an impairment may have occurred. We amortize all other intangible assets on a straight-line basis over their estimated useful lives.

The net carrying amount of our goodwill as of December 31, 2004 and 2003 was $413 million, all of which is included in our Pipelines segment. There was no change in the net carrying amount of our goodwill for the year ended December 31, 2004.

We also had other miscellaneous intangible assets of $6 million and $2 million as of December 31, 2004 and 2003.

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.

In 2004 we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $5 million, which is deferred as an actuarial gain in our postretirement benefit liabilities as of December 31, 2004. We expect that the adoption of this guidance will reduce our postretirement benefit expense by approximately $1 million in 2005.

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 the physical sale of natural gas, oil, condensate and NGL. 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.

Power revenues. Our Power 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.

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

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. See Note 8 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 power supply agreements). Prior to 2003, we also had derivative contracts related to our historical trading activities.

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, MCV, recognized a gain on one of its fuel supply contracts 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

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.

Pursuant to El Paso's policy, 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.

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 2004, 2003 and 2002. 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. For the years ended December 31, 2004, 2003 and 2002 the net foreign currency loss recorded in other expense was insignificant. 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 the translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholder's equity. The net cumulative currency translation gain (loss) recorded in accumulated other comprehensive income (loss) was $(6) million and $27 million at December 31, 2004 and 2003. 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. 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 fifteen years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates, projected inflation rates, and the estimated timing and amounts of settling our obligations, which are based on internal models and external quotes. The following is a summary of our asset retirement liabilities and the significant assumptions we used at December 31:

	2004	2003
	(In millions, except for rates)	
Current asset retirement liability	$ 25	$ 17
Non-current asset retirement liability[1]	$140	$ 122
Discount rates	6-8%	8-10%
Inflation rates	2.5%	2.5%

(1) We estimate that approximately 64% of our non-current asset retirement liability as of December 31, 2004 will be settled in the next five years.

Our asset retirement liabilities are recorded at their estimated fair value utilizing the assumptions above, 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.

The net asset retirement liability as of December 31, 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, were as follows:

	2004	2003
	(In millions)	
Net asset retirement liability at January 1	$139	$130
Liabilities settled	(19)	(22)
Accretion expense	15	17
Liabilities incurred	18	7
Changes in estimate	12	7
Net asset retirement liability at December 31	$165	$139

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, 2002, our aggregate current and non-current retirement liabilities on that date would have been approximately $113 million and our income from continuing operations and net income for the year ended December 31, 2002 would have been lower by $11 million.

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. These dividends were approximately $26 million in both 2004 and 2003. These dividends were recorded in interest expense in 2004, and $13 million of our 2003 dividends were recorded as interest expense and $13 million were recorded as distributions on preferred interests in our income statement in 2003.

Accounting for 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 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 or returns, including fees paid by the entity.

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.

Blue Lake Gas Storage owns and operates a 47 Bcf gas storage facility in Michigan. One of our subsidiaries operates the natural gas storage facility and we inject and withdraw all natural gas stored in the facility. We own a 75 percent equity interest in Blue Lake. This entity has $8 million of third party debt as of December 31, 2004 that is non-recourse to us. We consolidated Blue Lake because we are allocated a majority of Blue Lake's losses and returns through our equity interest in Blue Lake.

We have significant interests in a number of variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of December 31, 2004, these entities consisted primarily of 10 equity investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 2,900 gross MW. We operate many of these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. The long-term debt issued by these entities is recourse only to the power project. As a result, our exposure to these entities is limited to our equity investments in and advances to the entities ($501 million as of December 31, 2004) and our guarantees and other agreements associated with these entities (a maximum of $42 million as of December 31, 2004).

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2004, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Asset Retirement Obligations. In March 2005, the FASB Issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, which we adopted on January 1, 2003. FIN No. 47 requires that companies accrue this liability when a range of scenarios indicating the potential timing and settlement amounts of its conditional asset retirement obligations can be determined. We will adopt the provisions of this standard in the fourth quarter of 2005 and have not yet determined the impact, if any, that this pronouncement will have on our financial statements.

2. Divestitures

Sales of Assets and Investments

During 2004, 2003 and 2002, we completed and announced the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	2004	2003	2002
		(In millions)	
Regulated			
Pipelines	$ —	$ 89	$ 303
Non-regulated			
Production	24	137	1,248
Power	92	11	—
Field Services	3	94	120
Other			
Corporate	—	17	—
Total continuing(1)	119	348	1,671
Discontinued	1,291	803	177
Total	$1,410	$1,151	$1,848

(1) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $32 million, $35 million, and $33 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The following table summarizes the significant asset sales:

	2004	2003	2002
Pipelines	• None	• TX panhandle gathering system • 2.1% interest in Alliance pipeline • Sulfur extraction facility • Horsham pipeline in Australia	• Natural gas and oil properties located in TX, KS, and OK • 12.3% equity interest in Alliance pipeline • Typhoon natural gas pipeline
Production	• Brazilian exploration and production acreage	• Natural gas and oil properties in NM and the Gulf of Mexico • Drilling rigs	• Natural gas and oil properties located in TX, CO and Utah
Power	• Utility Contract Funding • Mohawk River Funding IV • Interest in Bastrop Company	• Mohawk River Funding I	• None
Field Services	• Dauphin Island and Mobile Bay equity investments	• Gathering systems located in WY • Midstream assets in the Mid-Continent regions	• Dragon Trail gas processing plant • Gathering facilities in Utah
Corporate	• None	• Aircraft	• None
Discontinued	• Natural gas and oil production properties in Canada and other international production assets • Aruba and Eagle Point refineries and other petroleum assets	• Corpus Christi refinery • Florida petroleum terminals • Louisiana lease crude • Coal reserves • Canadian natural gas and oil properties • Asphalt facilities	• Coal reserves and properties and petroleum assets • Natural gas and oil properties located in Western Canada

See Note 3 and 16 for a discussion of gains, losses and asset impairments related to the sales above.

During 2005, we have either completed or announced the following sales:

- Interest in paraxylene plant for $74 million;
- MTBE processing facility for $5 million;
- Eagle Point power facility for $3 million;
- Interest in Rensselaer power facility and its obligations; and
- South Louisiana gathering and processing assets for $500 million.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management and/or El Paso's Board of Directors and when they meet other criteria. As of December 31, 2004, we had two domestic power plants in assets held for sale, which were impaired in previous years and which we expect to sell within the next twelve months. As of December 31, 2003, we had $7 million of assets held for sale reflected in current assets on our balance sheet. Our assets held for sale as of December 31, 2003 related to domestic power assets in our Power segment that were approved by El Paso's Board of Directors for sale in 2003.

Discontinued Operations

South Louisiana Gathering and Processing Operations. During the second quarter 2005, El Paso's Board of Directors approved the sale of our south Louisiana gathering and processing assets. These assets were previously reported in our Field Services segment. As a result of the Board's actions, we reported these operations as discontinued operations for all periods presented. During the third quarter of 2005, we announced the sale of these assets, for which we expect to receive proceeds of approximately $500 million which is in excess of the carrying value of these assets. The sale of the south Louisiana gathering and processing assets is expected to be complete by the end of 2005.

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During 2004, we recognized approximately $22 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties by mid-2005.

Petroleum Markets. During 2003, the sales of our petroleum markets businesses and operations were approved. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. 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 impairment charges during 2003 of approximately $1.5 billion related to these assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately $59 million in 2003 from the sale of our Corpus Christi refinery, our asphalt assets, and our Florida terminalling and marine assets.

In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million and used a portion of the proceeds to repay approximately $370 million of debt associated with the Aruba refinery. We recorded realized losses of approximately $32 million in 2004, primarily from the sale of our Aruba and Eagle Point refineries. In addition, in 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing operations in our financial statements based on our decision to retain these operations. Our financial statements for all periods presented reflect this change.

Coal Mining. In 2002, our Board of Directors authorized the sale of our coal mining operations and we recorded an impairment of $185 million. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. The sale of these operations was completed in 2003 for $92 million in cash and $24 million in notes receivable, which were settled in the second quarter of 2004. We did not record a significant gain or loss on these sales.

The petroleum markets, other international natural gas and oil production operations, south Louisiana gathering and processing operations, and coal mining operations discussed above are classified as discontinued operations in our financial statements for all of the historical periods presented. Assets and liabilities of these discontinued businesses are classified as current and non-current assets and liabilities. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Coal Mining	Total
			(In millions)		
Operating Results Data					
Year Ended December 31, 2004 (Restated)[(1)]					
Revenues	$ 787	$ 31	$ 331	$ —	$ 1,149
Costs and expenses	(839)	(52)	(292)	—	(1,183)
Loss on long-lived assets	(36)	(22)	—	—	(58)
Other income (expense)	13	—	(2)	—	11
Interest and debt expense	(2)	1	—	—	(1)
Loss before income taxes	(77)	(42)	37	—	(82)
Income taxes	2	(6)	16	—	12
Income (loss) from discontinued operations, net of income taxes	$ (79)	$ (36)	$ 21	$ —	$ (94)
Year Ended December 31, 2003 (Restated)[(1)]					
Revenues	$ 5,652	$ 88	$ 245	$ 27	$ 6,012
Costs and expenses	(5,794)	(127)	(239)	(13)	(6,173)
Loss on long-lived assets	(1,404)	(89)	—	(9)	(1,502)
Other income (expenses)	(4)	—	—	1	(3)
Interest and debt expense	(11)	4	—	—	(7)
Income (loss) before income taxes	(1,561)	(124)	6	6	(1,673)
Income taxes	(263)	(135)	3	5	(390)
Income (loss) from discontinued operations, net of income taxes	$(1,298)	$ 11	$ 3	$ 1	$(1,283)
Year Ended December 31, 2002					
Revenues	$ 4,788	$ 71	$ 204	$ 309	$ 5,372
Costs and expenses	(4,916)	(148)	(202)	(327)	(5,593)
Loss on long-lived assets	(97)	(4)	—	(184)	(285)
Other income	20	—	—	5	25
Interest and debt expense	(12)	4	—	—	(8)
Loss before income taxes	(217)	(77)	2	(197)	(489)
Income taxes	16	(39)	7	(73)	(89)
Income (loss) from discontinued operations, net of income taxes	$ (233)	$ (38)	$ (5)	$(124)	$ (400)

(1) For 2004, amounts related to Petroleum Markets and International Natural Gas and Oil Production Operations were restated. For 2003, amounts related to International Natural Gas and Oil Production Operations were restated. See Note 1 for a further discussion of the restatements.

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Financial Position Data				
December 31, 2004				
Assets of discontinued operations				
Accounts and notes receivables	$ 39	$ 2	$ 65	$ 106
Inventory	8	—	6	14
Other current assets	3	1	8	12
Property, plant and equipment, net	14	6	81	101
Other non-current assets	33	—	8	41
Total assets of discontinued operations	$ 97	$ 9	$168	$ 274
Liabilities of discontinued operations				
Accounts payable	$ 5	$ —	$ 84	$ 89
Other current liabilities	3	—	9	12
Other non-current liabilities	3	—	31	34
Total liabilities	$ 11	$ —	$124	$ 135
December 31, 2003				
Assets of discontinued operations				
Accounts and notes receivables	$ 259	$ 22	$ 44	$ 325
Inventory	385	3	2	390
Other current assets	131	8	—	139
Property, plant and equipment, net	521	399	73	993
Intangible assets, net	—	6	—	6
Other non-current assets	70	—	—	70
Total assets of discontinued operations	$1,366	$438	$119	$1,923
Liabilities of discontinued operations				
Accounts payable	$ 172	$ 38	$ 62	$ 272
Other current liabilities	86	—	6	92
Long-term debt	374	—	—	374
Other non-current liabilities	26	3	35	64
Total liabilities	$ 658	$ 41	$103	$ 802

3. 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:

	2004	2003	2002
		(In millions)	
Net realized gain	$ (2)	$(35)	$(44)
Asset impairments			
Power	103	28	18
Production	—	10	—
Field Services	5	4	14
Corporate	—	1	—
Total asset impairments	108	43	32
Loss (gain) on long-lived assets	106	8	(12)
Loss on investments in unconsolidated affiliates(1)	292	128	47
Loss on assets and investments	$398	$136	$ 35

(1) See Note 16 for further description of these gains and losses.

Net Realized Gain

Our 2004 net realized gain was primarily related to the sale of assets within our Power segment.

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 a $5 million gain 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 2 for a further discussion of these divestitures.

Asset Impairments

Our impairment charges for the years ended December 31, 2004, 2003 and 2002 were recorded primarily in connection with our intent to dispose of, or reduce our involvement in a number of assets, including charges of $88 million in 2004 related to the planned sales of our domestic power contract restructuring assets.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 2 and 16.

4. Ceiling Test Charges

During the year ended December 31, 2004, we had no ceiling test charges. During the years ended December 31, 2003 and 2002, we incurred ceiling test charges in the following full cost pools:

	2003	2002
	(In millions)	
U.S.	$34	$417
Brazil and Other International	5	5
Total	$39	$422

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 2004 or 2003, and would have incurred charges of $576 million in 2002 compared with the charges we actually recorded.

5. 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:

	2004	2003	2002
		(In millions)	
Other Income			
Interest income	$13	$ 17	$13
Development, management and administrative services fees on power projects from affiliates	12	11	11
Allowance for funds used during construction	7	—	—
Re-application of SFAS No. 71 (CIG and WIC)	—	18	—
Favorable resolution of non-operating contingent obligations	—	8	31
Other	12	12	15
Total	$44	$ 66	$70
Other Expenses			
Loss on early extinguishment of debt	$10	$ —	$—
Minority interest in consolidated subsidiaries	1	(12)	52
Other	1	7	18
Total	$12	$ (5)	$70

6. Income Taxes

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

	2004	2003	2002
		(In millions)	
U.S.	$ 13	$234	$348
Foreign	(80)	2	139
	$(67)	$236	$487

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

	2004	2003	2002
		(In millions)	
Current			
Federal	$ 11	$ 67	$(33)
State	40	13	—
Foreign	—	—	5
	51	80	(28)
Deferred			
Federal	(5)	(14)	130
State	(48)	(10)	33
Foreign	(3)	(16)	1
	(56)	(40)	164
Total income taxes	$ (5)	$ 40	$136

Our income taxes, included in income (loss) from continuing operations differ 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:

	2004	2003	2002
		(In millions, except rates)	
Income taxes at the statutory federal rate of 35%	$(23)	$ 82	$171
Increase (decrease)			
State income taxes, net of federal income tax effect	(5)	3	22
Foreign (income) loss taxed at different rates	36	8	(55)
Non-taxable stock dividends	—	(5)	(5)
Abandonments and sales of foreign investments	(7)	(25)	—
Valuation allowances	—	(21)	(3)
Dispositions of domestic assets	(7)	—	—
Other	1	(2)	6
Income taxes	$ (5)	$ 40	$136
Effective tax rate	7%	17%	28%

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

	2004 (Restated)	2003 (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$1,200	$ 856
Investments in unconsolidated affiliates	103	302
Regulatory and other assets	54	80
Total deferred tax liability	1,357	1,238
Deferred tax assets		
Net operating loss and tax credit carryovers:		
U.S. federal	375	267
State	45	37
Foreign	29	7
Environmental liability	54	59
Price risk management activities	56	55
Allocated merger costs	106	107
Lease liabilities	30	2
Other	82	59
Valuation allowance	(25)	(1)
Total deferred tax asset	752	592
Net deferred tax liability	$ 605	$ 646

Historically, we have not recorded U.S. deferred tax liabilities on book versus tax basis differences in our Asian power investments because it was our intent to indefinitely reinvest the earnings from these projects outside the U.S. In 2004, our intent on these assets changed and we now intend to use the proceeds from the anticipated sale within the U.S. As a result, we recorded deferred tax liabilities which, as of December 31, 2004 were $8 million, representing those instances where the book basis in our investments in the Asian power projects exceeded the tax basis. At this time, however, due to uncertainties as to the manner, timing and approval of the sales, we have not recorded deferred tax assets for those instances where the tax basis of our investments exceeded the book basis, except in instances where we believe the realization of the asset is assured. As of December 31, 2004, total deferred tax assets recorded on our Asian investments was $6 million.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. At December 31, 2004, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $358 million. 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 adjustments recorded in accumulated other comprehensive income.

Under El Paso's tax accrual policy, we are allocated the tax effects associated with the sales of stock by employees under an employee stock purchase plan, the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends. This allocation did not have a material effect in 2004, however, it increased taxes payable by $4 million in 2003 and reduced taxes payable by $2 million in 2002. These tax effects are included in additional paid-in capital in our balance sheets.

As of December 31, 2004, we have U.S. federal alternative minimum tax credits and general business credits of $217 million that carryover indefinitely and capital loss carryovers of $11 million for which the carryover period ends in 2008. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2004.

	Carryover Period				
	2005	2006-2010	2011-2015	2016-2024 (Restated)	Total
			(In millions)		
U.S. federal net operating loss	$—	$ —	$—	$440	$440
State net operating loss	3	287	31	229	550

We also have $86 million of foreign net operating loss carryovers that carryover indefinitely. 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 the uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2004, we maintained a valuation allowance of $20 million related to state net operating loss carryovers and $5 million related to foreign deferred tax assets for book impairments and ceiling test charges. As of December 31, 2003, we maintained a valuation allowance of $1 million related to foreign deferred tax assets for ceiling charges. The change in our valuation allowances from December 31, 2003 to December 31, 2004 is primarily related to an additional valuation allowance for State of New Jersey legislation that limited use of state operating loss carryovers and an increase in valuation allowances related to foreign impairment of assets.

7. Fair Value of Financial Instruments

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

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Long-term financing obligations, including current maturities	$3,757	$3,931	$5,321	$5,233
Commodity-based price risk management derivatives	(148)	(148)	818	818

As of December 31, 2004 and 2003, the carrying amounts of cash and cash equivalents and trade receivables and payables represented 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 8 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2004 and 2003. 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:

	2004	2003
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$(148)	$(124)
Derivatives from power contract restructuring activities[1]	—	942
Net assets (liabilities) from price risk management activities[2]	$(148)	$ 818

(1) In 2004, we sold our subsidiaries that own these derivative contracts. See Note 2 for additional information on these sales.

(2) 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. For forward pricing data, we use commodity prices from market-based sources such as the New York Mercantile Exchange. We discount the estimated fair value of our derivatives 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 used the same methodology discussed above for determining the forward settlement prices but were discounted using a risk free interest rate, adjusted for the individual credit spread for each counterparty to the contract.

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, which primarily relate to our natural gas hedges, are designed to hedge forecasted sales transactions or limit 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 (loss) 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, 2004 and 2003 follows:

	Accumulated Other Comprehensive Income (Loss)		Estimated Income (Loss) Reclassification in 2005[1]	Final Termination Date
	2004	2003		
			(In millions)	
Held by consolidated entities	$ 28	$(49)	$ 28	2005
Held by unconsolidated affiliates	18	13	9	2006
Undesignated[2]	(113)	(25)	(113)	2005
Total[3]	$ (67)	$(61)	$ (76)	

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

(2) In December 2004 and May 2002, we removed the hedging designation on these derivatives.

(3) Accumulated other comprehensive income (loss) also includes $(6) million and $27 million of currency translation adjustments as of December 31, 2004 and 2003, as well as $(20) million and $(17) million of additional minimum pension liability, net of income taxes.

For the years ended December 31, 2004, 2003 and 2002, we recognized net losses of less than $1 million, $1 million and $3 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 Marketing 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 in our Power segment. For the year ended December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements:

	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)
			(In millions)			
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.

As a result of El Paso's credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and have sold our remaining restructured power contracts in 2004, completing the sales of UCF (which is the restructured Eagle Point power contract) and Mohawk River Funding IV. (See Note 2 for a discussion of these sales.)

9. Inventory

We have the following inventory as of December 31:

	2004	2003
	(In millions)	
Materials and supplies and other	$40	$52
Natural gas and NGL in storage	12	—
Total inventory	$52	$52

10. 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. Below are the details as of December 31, of our regulatory assets and liabilities for our regulated interstate systems that apply the provisions of SFAS No. 71, which are recoverable over various periods:

	2004	2003
	(In millions)	
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction[1]	$15	$12
Postretirement benefits[1]	6	6
Under-collected federal income taxes[1]	2	2
Total regulatory assets	$23	$20
Current regulatory liabilities		
Postretirement benefits[1]	$—	$ 1
Non-current regulatory liabilities		
Excess deferred federal income taxes	6	4
Over-collected fuel obligation	11	5
Total non-current regulatory liabilities	17	9
Total regulatory liabilities	$17	$10

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

11. Property, Plant and Equipment

At December 31, 2004 and 2003, we had approximately $280 million and $363 million of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2004 and 2003, 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, 2004, 2003 and 2002 was approximately $34 million. We do not currently earn a return on these excess purchase costs from our rate payers.

12. Debt, Other Financing Obligations and Other Credit Facilities

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

	2004	2003
	(In millions)	
Long-term debt		
El Paso CGP Company		
Senior notes, 6.2% through 7.75%, due 2004 through 2010	$ 930	$1,305
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,357	1,395
Power		
Non-recourse senior notes, 7.75% and 7.944%, due 2008 and 2016	—	904
Recourse notes 8.5%, due 2005	37	81
El Paso Production Company		
Floating rate notes, due 2005 and 2006	—	200
ANR Pipeline		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	800	800
Notes, 13.75% due 2010	12	13
Colorado Interstate Gas		
Debentures, 6.85% and 10.0%, due 2037 and 2005	280	280
Other	48	51
Subtotal	3,464	5,029
Other financing obligations		
Coastal Finance I	300	300
	3,764	5,329
Less:		
Unamortized discount on long-term debt	7	8
Current maturities of long-term debt	310	310
Total long-term financing obligations, less current maturities	$3,447	$5,011

During 2004 and to date in 2005, we had the following changes in our debt financing obligations:

Company	Type	Interest Rate	Principal (In millions)	Due Date
Issuances and other increases				
Blue Lake Gas Storage[1]	Non-recourse term loan	LIBOR + 1.2%	$ 14	2006
	Increase through December 31, 2004		14	
Colorado Interstate Gas Company	Senior Notes	5.95%	200	2015
	Increase through date of filing		$ 214	
Repayments, repurchases and other retirements				
El Paso CGP	Note	LIBOR + 3.5%	$ 200	
El Paso CGP	Note	6.2%	190	
Mohawk River Funding IV[2]	Non-recourse note	7.75%	72	
UCF[2]	Non-recourse senior notes	7.944%	815	
El Paso CGP	Notes	Various	185	
El Paso CGP	Senior Debentures	10.25%	38	
Other	Long-term debt	Various	79	
	Decreases through December 31, 2004		1,579	
Other	Long-term debt	Various	42	
	Decreases through date of filing		$1,621	

(1) This debt was consolidated as a result of adopting FIN No. 46 (see Note 1).
(2) The remaining balance of these debt obligations was eliminated when we sold our interests in Mohawk River Funding IV and UCF.

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

2005	$ 310
2006	330
2007	8
2008	416
2009	201
Thereafter	2,499
Total long-term financing obligations, including current maturities	$3,764

Included above in 2005 is $75 million of debentures that holders have the option to redeem on June 1, 2005, prior to their stated maturities. This $75 million is eligible for redemption solely on June 1, 2005 and, if not redeemed, will be reclassified to long-term debt in the second quarter of 2005. Included in the "thereafter" line of the table above are $300 million of debentures that holders have an option to redeem in 2007 prior to their stated maturity.

Credit Facilities

In November 2004, El Paso replaced its previous $3 billion revolving credit facility, which was scheduled to mature in June 2005, with a new $3 billion credit agreement with a group of lenders. Certain of our subsidiaries, ANR and CIG, continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement, which is collateralized by our interests in ANR, CIG, WIC, and ANR Storage Company.

As of December 31, 2004, under El Paso's $3 billion credit agreement, El Paso had $1.25 billion outstanding under the term loan and had utilized approximately all of the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to issue letters of credit, none of which was borrowed or issued on behalf of ANR or CIG.

Restrictive Covenants

Our restrictive covenants include restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, and cross-acceleration provisions.

Some of our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in cash management programs and limitations on our ability to prepay debt. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries.

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.

Other Financing Arrangements

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 percent 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, June 30, 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 2003, the amounts outstanding of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Non-Recourse Project Financings. Many of our power subsidiaries and investments have borrowed a material portion of the costs to acquire or construct assets. Such borrowings are made with recourse only to the project company and assets (i.e. without recourse to us). On occasion, events have occurred in connection with several of our projects that have either constituted an event of default under the loan agreements or could constitute an event of default upon delivery of a notice from the lenders and the failure of the subsidiary or investee to cure the event during an applicable grace period. We have several projects that we account for as equity investments that are in default under their loan agreements, including Saba. We have a $9 million interest in Saba. There is no recourse to us under the loans at these investments. In addition, we have had events of default or other events that could lead to an event of default upon notice from the lenders on other projects, but we do not believe any of these defaults will have a material impact on our or our subsidiaries' financial statements.

13. 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). Motions to dismiss have been filed on behalf of all defendants. 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. The plaintiffs have filed motions for class certification in both proceedings and the defendants have filed briefs in opposition thereto. 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 some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts 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 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 its December 31, 2003 natural gas and oil reserve revisions. El Paso and its Audit Committee have also received federal grand jury subpoenas for documents regarding the reserve revision. We are assisting El Paso and its Audit Committee in their efforts to cooperate with the SEC and the U.S. Attorney investigations into the matter.

Storage Reporting. In November 2004, ANR received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the Energy Information Administration (EIA) for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR provided information on its weekly EIA submissions for the weeks ending November 12, 2004 and November 19, 2004, ANR's submissions to the EIA were not revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC and ANR provided the requested information. On December 17, 2004, the FERC held a press conference at which they disclosed that their inquiry has determined that an unaffiliated third party was the source of the downward revision.

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. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with the Oil for Food Program. We have also received informal requests for information and documents from the United States Senate's Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to our purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney's, the SEC's, Senate Subcommittee's and the House Committee's investigations of this matter.

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. There are also 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.

For each of our outstanding legal and other contingent 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. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to these costs we may incur, based upon our evaluation and experience to date, 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 related to these matters and adjust our accounts accordingly. As of December 31, 2004, we had approximately $36 million accrued for all outstanding legal matters and other contingencies.

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, 2004, we had accrued approximately $128 million, including approximately $126 million for expected remediation costs 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 $128 million accrual, $44 million was reserved for facilities we currently operate, and $84 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $128 million to approximately $199 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 ($38 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($90 million to $161 million), and if no one amount in that range is more likely than any other, 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, 2004	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 44	$ 49
Non-operating	80	141
Superfund	4	9
Total	$128	$199

Below is a reconciliation of our accrued liability from January 1, 2004 to December 31, 2004 (in millions):

Balance as of January 1, 2004	$131
Additions/adjustments for remediation activities	9
Payments for remediation activities	(18)
Other changes, net	6
Balance as of December 31, 2004	$128

For 2005, we estimate that our total remediation expenditures will be approximately $31 million. In addition, we expect to make capital expenditures for environmental matters of approximately $24 million in the aggregate for the years 2005 through 2009. 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 27 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2004, we have estimated our share of the remediation costs at these sites to be between $4 million and $9 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 estimating our 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 environmental reserves are adequate.

Rates and Regulatory Matters

Pipeline Integrity Costs. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $6 million to $12 million annually over the next eight years.

Inquiry Regarding Income Tax Allowances. In December 2004, the Federal Energy Regulatory Commission (FERC) issued a Notice of Inquiry (NOI) in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC sought comments on whether the court's reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines, including those pipelines that are not owned by a corporate entity, such as Great Lakes Gas Transmission Limited Partnership which is jointly owned with unaffiliated parties.

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

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 2005 until 2031. As of December 31, 2004, our total commitments under operating leases were approximately $51 million. Minimum annual rental commitments under our operating leases at December 31, 2004, were as follows:

Year Ending December 31,	Operating Leases[(1)]
	(In millions)
2005	$18
2006	6
2007	3
2008	2
2009	2
Thereafter	20
Total	$51

(1) These amounts exclude our proportional share of minimum annual rental commitments paid by El Paso, which are allocated to us through an overhead allocation.

Rental expense on our operating leases for the years ended December 31, 2004, 2003 and 2002 was $60 million, $59 million and $49 million. These amounts include our share of the overhead allocation from El Paso.

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, 2004, we had approximately $10 million of both financial and performance guarantees, not otherwise reflected in our financial statements. These 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, 2004, we had firm commitments under transportation contracts of $6 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $133 million. Included in other purchase and capital commitments above at December 31, 2004, are unconditional purchase obligations entered into by our pipelines for products and services totaling $113 million for 2005.

14. 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 former coal operations who are covered under a separate plan.

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 another pension plan that is closed to new participants and provides benefits to former employees of our previously discontinued coal operations. El Paso anticipates that contributions to this pension plan will be less than $1 million in 2005.

El Paso also maintains a defined contribution retirement savings plan covering its U.S. employees, including our employees. 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.

El Paso is responsible for benefits accrued under its pension, other postretirement and retirement savings plans and allocates the related costs to its affiliates.

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	
	2004	2003	2004	2003
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$81	$79	$100	$102
Service cost	—	2	—	—
Interest cost	5	4	6	6
Participant contributions	—	—	5	5
Curtailment and special termination benefit	—	(8)	—	(6)
Actuarial loss (gain)	7	7	(1)	10
Projected benefits paid	(4)	(3)	(15)	(17)
Projected benefit obligation at end of period	$89	$81	$ 95	$100
Change in plan assets:				
Fair value of plan assets at beginning of period	$63	$59	$ 59	$ 46
Actual return on plan assets	7	7	5	8
Employer contributions	—	—	17	17
Participant contributions	—	—	5	5
Projected benefits paid	(4)	(3)	(15)	(17)
Fair value of plan assets at end of period	$66	$63	$ 71	$ 59
Reconciliation of funded status:				
Fair value of plan assets at September 30	$66	$63	$ 71	$ 59
Less: Projected benefit obligation at end of period	89	81	95	100
Funded status at September 30	(23)	(18)	(24)	(41)
Fourth quarter contributions and income	—	—	3	4
Unrecognized net actuarial loss (gain)	30	25	(27)	(24)
Prepaid (accrued) benefit cost at December 31,	$ 7	$ 7	$(48)	$(61)

	Pension Benefits	
	2004	2003
	(In millions)	
Amounts recognized in the statement of financial position consist of:		
Accrued benefit liability	$(23)	$(18)
Accumulated other comprehensive loss	30	25
Net amount recognized at year-end	$ 7	$ 7

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

	2004	2003
	(In millions)	
Projected benefit obligation	$89	$81
Accumulated benefit obligation	89	81
Fair value of plan assets	66	63

Future benefits expected to be paid from our pension plans and our other postretirement plans as of December 31, 2004, were as follows:

Year Ending December 31,	Pension Benefits	Other Postretirement Benefits[(1)]
	(In millions)	
2005	$ 4	$10
2006	4	9
2007	4	9
2008	4	9
2009	4	8
2010-2014	24	40
Total	$44	$85

(1) Includes a reduction of less than $1 million in each year for an expected subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

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,					
	2004	2003	2002	2004	2003	2002
	(In millions)					
Service cost	$—	$ 2	$ 3	$—	$—	$ 1
Interest cost	5	5	5	6	6	8
Expected return on plan assets	(5)	(6)	(7)	(3)	(2)	(2)
Amortization of net actuarial loss	—	—	—	(1)	(1)	(1)
Curtailment and special termination benefits	—	1	—	—	(6)	—
Net benefit cost (income)	$—	$ 2	$ 1	$ 2	$(3)	$ 6

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 $5 million in 2004 and $6 million in 2003 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 2004, 2003 and 2002:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	5.75	6.00		5.75	6.00	
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.00	6.75	7.25	6.00	6.75	7.25
Expected return on plan assets[(1)]	8.50	8.80	8.80	7.50	7.50	7.50
Rate of compensation increase	—[(2)]	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 35 percent to 39 percent on other 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 2005, the assumed expected return on assets for pension benefits will be reduced to 8 percent.

(2) In 2003, our pension plan was closed to new participants and, as a result, it provides benefits solely to former employees.

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 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point increase (decrease) in assumed health care cost trends would have increased (decreased) our accumulated postretirement obligation by $3 million and would not have significantly impacted our service cost or interest cost as of and for the periods ended September 30, 2004 and 2003.

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 2004**	**Actual 2003**	**Target**	**Actual 2004**	**Actual 2003**
		(Percent)			**(Percent)**	
Equity securities[1]	60	62	70	65	58	28
Debt securities	40	37	29	35	32	58
Other	—	1	1	—	10	14
Total	100	100	100	100	100	100

(1) Actuals for our pension plans include $2 million (3 percent of total assets) and $1 million (2.1 percent of total assets) of El Paso's common stock at September 30, 2004 and September 30, 2003.

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 2003, we modified our target asset allocations for our other postretirement benefit plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2004 were close to our target. During 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 2005 assumption related to the expected return on plan assets was reduced from 8.5% to 8.0% to reflect this change.

15. Business Segment Information

During 2004, we reorganized our business structure into two primary business lines, regulated and non-regulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established an individual Power segment. All periods presented reflect this change in segments. Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Power, and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions as well as various other contracts and assets, all of which are immaterial.

During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations. During the second quarter of 2005, we reclassified our south Louisiana gathering and processing assets from our Field Services segment to discontinued operations. Our operating results for all periods presented reflect these changes.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. We conduct our activities primarily through four wholly owned transmission systems and a partially owned interstate transmission system 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 the United States and Brazil. In the United States, Production has onshore operations and properties primarily in Texas, Utah, West Virginia and Wyoming and offshore operations and properties in federal and state waters in the Gulf of Mexico.

Our Power segment owns and has interests in domestic and international power assets. As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also had domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets primarily in Texas and Utah.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2004, 2003 and 2002.

We use earnings before interest expense 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, which includes interest and debt expense and affiliated interest expense, and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of all of our businesses and investments. Also, we exclude interest and distributions on preferred interests of consolidated subsidiaries from this measure 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 reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

	2004	2003	2002
		(In millions)	
Total EBIT	$ 274	$ 701	$ 956
Interest and debt expense	(341)	(407)	(425)
Affiliated interest expense, net	—	(41)	(9)
Distributions on preferred interests of consolidated subsidiaries	—	(17)	(35)
Income taxes	5	(40)	(136)
Income (loss) from continuing operations	$ (62)	$ 196	$ 351

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

	Segments As of or for the Year Ended December 31, 2004					
	Regulated	Non-regulated				
	Pipelines	Production	Power	Field Services	Corporate(1)	Total
	(In millions)					
Revenues from external customers						
Domestic	$ 848	$ 646(2)	$ 59	$150	$ 53	$1,756
Foreign	—	—	90	—	—	90
Intersegment revenue	10	44	—	1	(12)	43(7)
Operation and maintenance	252	173	83	1	(4)	505
Depreciation, depletion and amortization	123	315	11	2	12	463
Loss (gain) on long-lived assets	(1)	—	102	5	—	106
Operating income (loss)	$ 350	$ 174	$ (97)	$ 6	$ 2	$ 435
Earnings (losses) from unconsolidated affiliates	72	(3)	(273)	11	—	(193)
Other income	17	—	15	—	12	44
Other expense	(5)	—	6	1	(14)	(12)
EBIT	$ 434	$ 171	$(349)	$ 18	$ —	$ 274
Discontinued operations, net of income taxes (Restated)(6)	$ —	$ (36)	$ —	$ 21	$(79)	$ (94)
Assets of continuing operations(3)						
Domestic	5,717	1,769	223	144	425	8,278
Foreign(4)	—	231	493	—	68	792
Capital expenditures and investments in and advances to unconsolidated affiliates, net(5)	527	276	(1)	(1)	1	802
Total investments in unconsolidated affiliates	362	—	478	48	6	894

(1) Includes 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 recorded an intersegment revenue elimination of $12 million and an operation and maintenance elimination of less than $1 million, which is included in the "Corporate" 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) Excludes assets of discontinued operations of $274 million (see Note 2).

(4) Of total foreign assets, approximately $352 million relates to property, plant, and equipment and approximately $360 million relates to investments in and advances to unconsolidated affiliates.

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

(6) See Note 1 to the consolidated financial statements for a discussion of the restatement of these amounts.

(7) Relates to intercompany activity between our continuing operations and our discontinued operations.

	Regulated	Non-regulated				
	Pipelines	Production	Power	Field Services	Corporate[1]	Total
	Segments As of or for the Year Ended December 31, 2003 (In millions)					
Revenues from external customers						
Domestic	$ 915	$ 710[2]	$ 175	$ 82	$ 38	$ 1,920
Foreign	2	—	77	2	—	81
Intersegment revenue	1	112	—	26	(29)	110[3]
Operation and maintenance	246	164	105	(1)	(7)	507
Depreciation, depletion and amortization	108	347	14	3	11	483
Ceiling test charges	—	39	—	—	—	39
Loss (gain) on long-lived assets	(11)	5	28	(13)	(1)	8
Operating income (loss)	$ 397	$ 207	$ 22	$ 35	$ (19)	$ 642
Earnings (losses) from unconsolidated affiliates	75	10	(6)	(93)	2	(12)
Other income	32	2	13	—	19	66
Other expense	(4)	—	10	—	(1)	5
EBIT	$ 500	$ 219	$ 39	$(58)	$ 1	$ 701
Discontinued operations, net of income taxes (Restated)[6]	$ —	$ 11	$ —	$ 3	$(1,297)	$(1,283)
Cumulative effect of accounting changes, net of income taxes	(4)	(6)	—	(2)	—	(12)
Assets of continuing operations[4]						
Domestic (Restated)[6]	5,271	1,950	1,533	105	695	9,554
Foreign	—	233	601	—	99	933
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	192	600	(4)	3	(19)	772
Total investments in unconsolidated affiliates	397	52	804	54	5	1,312

(1) Includes 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 recorded an intersegment revenue elimination of $22 million and an operation and maintenance expense elimination of $1 million which is included in the "Corporate" 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 $1.9 billion (see Note 2).

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

(6) See Note 1 to the consolidated financial statements for a discussion of the restatement of these amounts.

	Segments As of or for the Year Ended December 31, 2002					
	Regulated	Non-regulated				
	Pipelines	Production	Power	Field Services	Corporate[1]	Total
	(In millions)					
Revenues from external customers						
Domestic	$ 901	$1,092[2]	$1,051	$201	$ 47	$3,292
Foreign	3	—	154	3	—	160
Intersegment revenue	30	95	11	52	(59)	129[3]
Operation and maintenance expenses	235	219	239	21	17	731
Depreciation, depletion and amortization	116	447	19	(3)	13	592
Ceiling test charges	—	422	—	—	—	422
Loss (gain) on long-lived assets	(12)	1	18	(21)	2	(12)
Operating income (loss)	$ 419	$ 24	$ 397	$ 66	$ (63)	$ 843
Earnings (losses) from unconsolidated affiliates	105	4	57	(53)	—	113
Other income	16	1	19	—	34	70
Other expense	(3)	—	(57)	—	(10)	(70)
EBIT	$ 537	$ 29	$ 416	$ 13	$ (39)	$ 956
Discontinued operations, net of income taxes	$ —	$ (38)	$ —	$ (5)	$(357)	$ (400)
Cumulative effect of accounting changes, net of income taxes	—	—	14	—	—	14
Assets of continuing operations[4]						
Domestic	5,128	2,203	1,698	341	583	9,953
Foreign	47	131	623	14	170	985
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	252	949	(26)	15	99	1,289
Total investments in unconsolidated affiliates	404	90	851	143	17	1,505

(1) Includes 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 recorded an intersegment revenue elimination of $59 million and an operation and maintenance expense elimination of $5 million, which is included in the "Corporate" 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 $4.6 billion.

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

16. Investments in, Earnings from and Transactions with Unconsolidated Affiliates and 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, 2004 and 2003 by $217 million and $37 million. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the year ended December 31:

	Net Ownership Interest		Investment		Earnings from Unconsolidated Affiliates		
	2004	2003	2004	2003	2004	2003	2002
	(Percent)		(In millions)		(In millions)		
Domestic:							
Great Lakes Gas Transmission[(1)]	50	50	$316	$ 325	$ 65	$ 57	$ 63
Midland Cogeneration Venture[(2)]	44	44	191	348	(171)	29	28
Javelina	40	40	45	40	15	(2)	—
Wyco Development	50	50	26	24	2	2	2
Bastrop Company[(3)]	—	50	—	73	(1)	(48)	(5)
Mobile Bay Processing[(3)]	—	42	—	11	—	(48)	(2)
Blue Lake Gas Storage[(4)]	—	75	—	30	—	9	8
Dauphin Island[(3)]	—	15	—	—	—	(40)	(1)
Alliance Pipeline Limited Partnership[(5)]	—	—	—	—	—	—	25
Aux Sable NGL[(5)]	—	—	—	—	—	—	(50)
Other Domestic Investments	various	various	29	77	(3)	27	11
Total domestic			607	928	(93)	(14)	79
Foreign:							
EGE Itabo	25	25	88	87	1	1	(2)
EGE Fortuna	25	25	65	59	6	3	5
Khulna Power Company	74	74	21	40	(18)	1	1
Habibullah Power[(6)]	50	50	20	48	(46)	(3)	10
Saba Power Company	94	94	7	59	(51)	4	7
Other Foreign Investments[(6)]	various	various	86	91	8	(4)	13
Total foreign			287	384	(100)	2	34
Total investments in unconsolidated affiliates			$894	$1,312			
Total earnings (losses) from unconsolidated affiliates					$(193)	$(12)	$113

(1) Includes a 47 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 3 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.

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

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

(4) Consolidated in 2004.

(5) In 2003 we completed the sale of our interest in this investment.

(6) As of December 31, 2004 and 2003, we also had outstanding advances of $64 million and $90 million related to our investment in Habibullah Power. We also had other outstanding advances of $9 million and $13 million related to our other foreign investments as of December 31, 2004 and 2003.

Our impairment charges and gains and losses on sales of equity investments that are included in equity earnings (losses) from unconsolidated affiliates during 2004, 2003 and 2002 consisted of the following:

Investment	Pre-Tax Gain (Loss) (In millions)	Cause of Impairments or Gain (Loss)
2004		
Asian assets	$(131)	Anticipated sales of investments
Midland Cogeneration Venture	(161)	Decline in investment's fair value based on increased fuel costs
	$(292)	
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

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 $108 million, $98 million and $127 million in 2004, 2003 and 2002, which includes $2 million, $17 million and $6 million of returns of capital, in 2004, 2003 and 2002 from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $21 million, $20 million and $25 million in 2004, 2003 and 2002 and total assets of $474 million and $536 million as of December 31, 2004 and 2003.

	Year Ended December 31,		
	2004	2003	2002
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$830	$807	$799
Operating expenses	630	590	542
Income from continuing operations	83	90	125
Net income	83	90	148

	December 31,	
	2004	2003
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 517	$ 468
Non-current assets	2,013	2,386
Short-term debt	158	99
Other current liabilities	183	249
Long-term debt	813	905
Other non-current liabilities	194	181
Minority interest	71	71
Equity in net assets	1,111	1,349

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $103 million. We own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. We also own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso. As a consequence of economic conditions described above, combined with the high prices on imported fuels and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales which may affect CEPP's ability to operate. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments may occur.

Related Party Transactions

The following table shows revenues and charges resulting from transactions with our related parties:

	2004	2003	2002
		(In millions)	
Revenues[1]	$535	$856	$1,412
Cost of sales[1]	86	74	159
Reimbursement for operating expenses	3	4	3
Charges from affiliates	204	277	268
Other income	14	15	9

(1) Includes adjustment for the reclassification of our south Louisiana gathering and processing assets as discontinued operations.

Revenues and Expenses. 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. Substantially all of our revenues and cost of sales from related parties for the years ended December 31, 2004, 2003 and 2002 were with El Paso affiliates, and primarily related to transactions with our Production segment. We have also entered into a service agreement with El Paso that provides for a reimbursement of 2.5 cents per MMBtu in 2005 for our expected administrative costs associated with hedging transactions we entered into in December 2004.

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 2004, 2003 and 2002, the annual charges were $70 million, $152 million and $146 million. During 2004, 2003 and 2002 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 2004, 2003 and 2002 the annual charges were $54 million, $48 million and $40 million. El Paso also provides our Production segment administrative and other shared production services and allocated $75 million, $73 million and $76 million in 2004, 2003 and 2002, net of capitalized amounts. We believe the allocation methods are reasonable.

Cash Management Program and Affiliate Receivables/Payables. 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, 2004 and December 31, 2003, we had borrowed $166 million and $906 million. The market rate of interest as of December 31, 2004 was 2.0% and at December 31, 2003, it was 2.8%. On December 31, 2003, El Paso's Board of Directors authorized a capital contribution of $1.5 billion to us as further discussed below, which reduced our total payables outstanding under this program. We also had other notes payable to related parties of $45 million and $43 million and other accounts payable to related parties of $61 million and $67 million at December 31, 2004 and December 31, 2003.

In addition, we had a demand note receivable with El Paso of $177 million at December 31, 2004, at an interest rate of 2.7%. At December 31, 2003, the demand note receivable was $275 million at an interest rate of 1.7%. Also, at December 31, 2004 and December 31, 2003, we had accounts and notes receivable from related parties of $87 million and $167 million. In addition, we had non-current advances to unconsolidated affiliates of $69 million and $127 million included in other non-current assets at December 31, 2004 and at December 31, 2003.

Affiliate income taxes. We are a party to a tax accrual policy with El Paso whereby El Paso files U.S. and certain state tax returns on our behalf. In certain states, we file and pay directly to the state taxing authorities. We have U.S. federal and state income taxes payable of $47 million and $42 million at December 31, 2004 and 2003, included in other current liabilities on our balance sheets. The balances due to El Paso will become payable under the tax accrual policy. See Note 1 for a discussion of our tax accrual policy.

Contributions from Parent. In 2004, El Paso made a capital contribution of $45 million to us. On December 31, 2003, El Paso's Board of Directors authorized a capital contribution of $1.5 billion to us, which was paid in 2003. Also in 2003, El Paso made an additional capital contribution of $24 million to us. 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. These contributions are reflected in our stockholder's equity statement as increases in our additional paid in capital.

Acquisitions and Divestitures. 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. We recorded the difference between the net book value and proceeds of $170 million as an increase to additional paid in capital.

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.

Other. During the first quarter of 2004, Coastal Stock Company, our wholly-owned subsidiary, issued 68,000 shares of its Class A Preferred Stock to a subsidiary of El Paso for $71 million. We included the proceeds from the issuance of these shares as securities of subsidiaries in our balance sheet.

Report of Independent Registered Public Accounting Firm

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

In our opinion, based on our audits and the report of other auditors, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, stockholder's equity and cash flows present fairly, in all material respects, the consolidated financial position of El Paso CGP Company and its subsidiaries (the "Company") at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, based on our audits, the financial statement schedule 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 did not audit the consolidated financial statements of Great Lakes Gas Transmission Limited Partnership (the "Partnership"), an equity method investment of the Company, which constitutes investments in unconsolidated affiliates of $316 million and $325 million at December 31, 2004 and 2003, respectively, and earnings from unconsolidated affiliates of $65 million, $57 million and $63 million, respectively, for the three years in the period ended December 31, 2004. Those statements were audited by other auditors, whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it related to the amounts included for the Partnership is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 described in Note 1, the Company restated its 2003 and 2004 financial statements. As discussed in Note 1, the Company adopted FASB Financial Interpretation No. 46, *Consolidation of Variable Interest Entities* on January 1, 2004; FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* on July 1, 2004; 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; and EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2* on October 1, 2002.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
April 15, 2005, except for the restatement
described in the second paragraph of
Note 1 to the consolidated financial statements
as to which the date is June 15, 2005, and
except for the reclassification of the south
Louisiana gathering and processing assets to
discontinued operations as described in the
first paragraph under "Discontinued
Operations" in Note 2 to the consolidated
financial statements as to which the date is
November 4, 2005

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				
	March 31 (Restated)[1]	June 30	September 30	December 31	Total
			(In millions)		
2004					
Operating revenues	$475	$449	$472	$ 493	$1,889
Loss (gain) on long-lived assets	88	—	6	12	106
Operating income	80	139	79	137	435
Income (loss) from continuing operations	$ 4	$ 55	$ 30	$(151)	$ (62)
Discontinued operations, net of income taxes[2]	(90)	(5)	(4)	5	(94)
Net income (loss)	$(86)	$ 50	$ 26	$(146)	$ (156)

	Quarters Ended				
	March 31	June 30	September 30	December 31 (Restated)[1]	Total
			(In millions)		
2003					
Operating revenues	$ 660	$ 537	$450	$464	$ 2,111
Ceiling test charges	—	—	39	—	39
Loss (gain) on long-lived assets	—	(30)	6	32	8
Operating income	266	221	74	81	642
Income (loss) from continuing operations	$ 130	$ 42	$ (4)	$ 28	$ 196
Discontinued operations, net of income taxes[2]	(216)	(926)	(65)	(76)	(1,283)
Cumulative effect of accounting changes, net of income taxes	(12)	—	—	—	(12)
Net loss	$ (98)	$(884)	$(69)	$(48)	$(1,099)

(1) Listed below are the amounts we originally reported in our Form 10-K for the quarters ended:

	Quarters Ended	
	March 31, 2004	December 31, 2003
Discontinued operations, net of income taxes	$(122)	$(111)
Net income (loss)	(118)	(83)

(2) Our petroleum markets, our Canadian and certain other international natural gas and oil production operations, coal mining operations and south Louisiana gathering and processing assets are classified as discontinued operations. (See Note 2 for further discussion).

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 in the United States and Brazil. In the United States, we have onshore operations and properties primarily in Texas, Utah, West Virginia and Wyoming and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Brazil.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31:

	United States	Brazil	Worldwide
		(In millions)	
2004			
Natural gas and oil properties:			
Costs subject to amortization[1]	$6,805	$207	$7,012
Costs not subject to amortization	55	86	141
	6,860	293	7,153
Less accumulated depreciation, depletion and amortization	5,235	82	5,317
Net capitalized costs	$1,625	$211	$1,836
SFAS No. 143 abandonment liability	$ 149	$ —	$ 149
2003			
Natural gas and oil properties:			
Costs subject to amortization[1]	$6,847	$146	$6,993
Costs not subject to amortization	119	117	236
	6,966	263	7,229
Less accumulated depreciation, depletion and amortization	5,307	58	5,365
Net capitalized costs	$1,659	$205	$1,864
SFAS No. 143 abandonment liability	$ 131	$ —	$ 131

(1) In January 1, 2003, we adopted SFAS No. 143 which is further discussed in Note 1. Included in our costs subject to amortization at December 31, 2004 and 2003 are SFAS No. 143 asset values of $88 million and $77 million primarily for the United States.

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

	United States	Brazil	Worldwide
		(In millions)	
2004			
Property acquisition costs			
Proved properties	$ 6	$—	$ 6
Unproved properties	4	3	7
Exploration costs(1)	87	24	111
Development costs(1)	150	1	151
Costs expended	247	28	275
Asset retirement obligation costs	11	—	11
Total costs incurred	$258	$28	$286

	United States	Brazil	Worldwide
		(In millions)	
2003			
Property acquisition costs			
Unproved properties	$ 9	$ 4	$ 13
Exploration costs(1)	216	95	311
Development costs(1)	270	—	270
Costs expended	495	99	594
Asset retirement obligation costs(2)	77	—	77
Total costs incurred	$572	$99	$671
2002			
Property acquisition costs			
Proved properties	$ 23	$—	$ 23
Unproved properties	12	9	21
Exploration costs	197	45	242
Development costs	569	—	569
Total costs incurred	$801	$54	$855

(1) Excludes approximately $32 million and $57 million that was paid in 2004 and 2003 by third parties under net profits interest agreements described beginning on page 102.

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. The cumulative effect of adopting SFAS No. 143 was $6 million.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $21 million, $50 million, and $70 million and capitalized interest of $4 million, $7 million and $7 million for the years ended December 31, 2004, 2003 and 2002.

In our January 1, 2005 reserve report, the amounts estimated to be spent in 2005, 2006 and 2007 to develop our worldwide booked proved undeveloped reserves are $27 million, $71 million and $113 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, 2004, pending determination of proved reserves:

	Cumulative Balance December 31, 2004	Costs Excluded for Years Ended December 31, 2004	2003	2002	Cumulative Balance December 31, 2001
		(In millions)			
Worldwide(1)(2)					
Acquisition	$ 57	$13	$17	$15	$12
Exploration	81	28	46	6	1
Development	3	1	—	—	2
	$141	$42	$63	$21	$15

(1) Includes operations in the United States and Brazil.

(2) Includes capitalized interest of $4 million, $2 million, and less than $1 million for the years ended December 31, 2004, 2003, and 2002.

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 2005 through 2008. For the United States, the unit of production depletion cost per Mcfe, including ceiling test charges, was $2.42, $2.06, and $2.98 in 2004, 2003, and 2002. Excluding ceiling test charges, our amortization expense per Mcfe would have been $2.42, $1.84 and $1.52 in 2004, 2003 and 2002. Included in our depreciation, depletion, and amortization expense is accretion expense of $0.12 and $0.08 per Mcfe for 2004 and 2003 attributable to SFAS No. 143 which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, including condensate and crude oil, and changes in these reserves at December 31, 2004 are presented below. Information in this table is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserves prepared by Ryder Scott Company was within one percent of our internally prepared estimates presented in these tables. Ryder Scott Company was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our proved properties based on value. 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.

	Natural Gas (Bcf)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[(1)]			
January 1, 2002	1,475	—	1,475
Revisions of previous estimates	(164)	—	(164)
Extensions, discoveries and other	279	—	279
Purchases of reserves in place	—	—	—
Sales of reserves in place	(504)	—	(504)
Production	(247)	—	(247)
December 31, 2002	839	—	839
Revisions of previous estimates	(30)	—	(30)
Extensions, discoveries and other	91	—	91
Purchases of reserves in place	3	—	3
Sales of reserves in place[(2)]	(136)	—	(136)
Production	(142)	—	(142)
December 31, 2003	625	—	625
Revisions of previous estimates	(40)	—	(40)
Extensions, discoveries and other	26	—	26
Purchases of reserves in place	—	—	—
Sales of reserves in place[(2)]	(3)	—	(3)
Production	(96)	—	(96)
December 31, 2004	512	—	512
Proved developed reserves			
December 31, 2002	633	—	633
December 31, 2003	502	—	502
December 31, 2004	419	—	419

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

(2) Sales of reserves in place include 3,434 MMcf and 11,416 MMcf of natural gas conveyed to third parties under net profits interest agreements in 2004 and 2003.

	Oil and Condensate (MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	23,846	—	23,846
Revisions of previous estimates	1,294	—	1,294
Extensions, discoveries and other	3,125	—	3,125
Purchases of reserves in place	—	—	—
Sales of reserves in place	(2,083)	—	(2,083)
Production	(5,136)	—	(5,136)
December 31, 2002	21,046	—	21,046
Revisions of previous estimates	784	—	784
Extensions, discoveries and other	2,332	20,543	22,875
Purchases of reserves in place	5	—	5
Sales of reserves in place[2]	(534)	—	(534)
Production	(3,871)	—	(3,871)
December 31, 2003	19,762	20,543	40,305
Revisions of previous estimates	319	252	571
Extensions, discoveries and other	1,889	—	1,889
Purchases of reserves in place[2]	—	—	—
Sales of reserves in place	(8)	—	(8)
Production	(2,603)	—	(2,603)
December 31, 2004	19,359	20,795	40,154
Proved developed reserves			
December 31, 2002	15,290	—	15,290
December 31, 2003	13,577	—	13,577
December 31, 2004	13,972	—	13,972

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

(2) Sales of reserves in place include 8 MBbl and 428 MBbl of oil and condensate conveyed to third parties under net profits agreements in 2004 and 2003.

	Natural Gas Liquids (MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	25,680	—	25,680
Revisions of previous estimates	(3,240)	—	(3,240)
Extensions, discoveries and other	3,989	—	3,989
Purchases of reserves in place	—	—	—
Sales of reserves in place	(9,200)	—	(9,200)
Production	(1,792)	—	(1,792)
December 31, 2002	15,437	—	15,437
Revisions of previous estimates	(3,048)	—	(3,048)
Extensions, discoveries and other	1,323	—	1,323
Purchases of reserves in place	38	—	38
Sales of reserves in place[2]	(485)	—	(485)
Production	(2,107)	—	(2,107)
December 31, 2003	11,158	—	11,158
Revisions of previous estimates	(758)	—	(758)
Extensions, discoveries and other	53	—	53
Purchases of reserves in place	—	—	—
Sales of reserves in place[2]	(47)	—	(47)
Production	(1,807)	—	(1,807)
December 31, 2004	8,599	—	8,599
Proved developed reserves			
December 31, 2002	13,175	—	13,175
December 31, 2003	9,559	—	9,559
December 31, 2004	7,684	—	7,684

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

(2) Sales of reserves in place include 47 MBbl and 85 MBbl of NGL conveyed to third parties under net profits agreements in 2004 and 2003.

During 2004, we had approximately 43 Bcfe of negative reserve revisions in the United States that were largely performance-driven. Our negative reserve revisions were concentrated in the Texas Gulf Coast region and offshore in the Gulf of Mexico:

Onshore. The onshore region recorded 12 Bcfe of positive reserve revisions. These revisions were created by better-than-anticipated performance in the Rockies.

Texas Gulf Coast. The Texas Gulf Coast region recorded 20 Bcfe of negative reserve revisions. The negative revisions were caused by performance revisions to proved producing wells, mechanical failures and lower-than-expected results from the 2004 development drilling program.

Offshore. The offshore region recorded 34 Bcfe of negative reserve revisions in the Gulf of Mexico. The revisions are a result of mechanical failures and adjustments to proved undeveloped reserves as a result of production performance in offsetting locations.

There are numerous uncertainties inherent in estimating quantities of proved reserves projecting future rates of production, and projecting the 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. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. 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, 2004.

In 2003, we entered into agreements to sell interests in a maximum of 42 wells to a subsidiary of Lehman Brothers and a subsidiary of Nabors Industries. As these wells are developed, Lehman and Nabors 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, Lehman and Nabors 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 two percent overriding royalty interest in the wells for the remainder of the wells' productive life. We do not guarantee a return or the recovery of Lehman and Nabors costs. All parties to the agreement have the right to cease participation in the agreement at any time, at which time Lehman and Nabors will continue to receive their net profits interest on wells previously started, but will relinquish their right to participate in any future wells. During 2004, we have sold interests in 22 wells and total proved reserves of 3,434 MMcf of natural gas and 55 MBbl of oil, condensate and NGL. They have paid $32 million of drilling and development costs and were paid $41 million of the revenues net of $4 million of expenses associated with these wells for the year ended December 31, 2004. In March 2005, we acquired all of the interests held by the Lehman subsidiary for $22 million.

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

	United States	Brazil	Worldwide
		(In millions)	
2004			
Net Revenues			
Sales to external customers	$ 183	$—	$ 183
Intersegment sales	492	—	492
Total	675	—	675
Production costs[(1)]	(107)	—	(107)
Depreciation, depletion and amortization[(2)]	(315)	—	(315)
	253	—	253
Income tax expense	(92)	—	(92)
Results of operations from producing activities	$ 161	$—	$ 161

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

(2) In January 2003 we adopted SFAS No. 143, which is further discussed in Note 1. Our depreciation, depletion and amortization includes accretion expense for SFAS No. 143 asset retirement obligations of $14 million and $16 million primarily for the United States in 2004 and 2003.

	United States	Brazil	Worldwide
		(In millions)	
2003			
Net Revenues			
Sales to external customers	$ 683	$—	$ 683
Intersegment sales	109	—	109
Total	792	—	792
Production costs(1)	(114)	—	(114)
Depreciation, depletion and amortization(2)	(347)	—	(347)
Ceiling test and other charges	(34)	(5)	(39)
	297	(5)	292
Income tax expense	(106)	2	(104)
Results of operations from producing activities	$ 191	$(3)	$ 188
2002			
Net Revenues			
Sales to external customers	$1,021	$—	$1,021
Intersegment sales	106	—	106
Total	1,127	—	1,127
Production costs(1)	(162)	—	(162)
Depreciation, depletion and amortization	(446)	—	(446)
Ceiling test and other charges	(417)	—	(417)
	102	—	102
Income tax expense	(35)	—	(35)
Results of operations from producing activities	$ 67	$—	$ 67

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

(2) In January 2003 we adopted SFAS No. 143, which is further discussed in Note 1. Our depreciation, depletion and amortization includes accretion expense for SFAS No. 143 asset retirement obligations of $14 million and $16 million primarily for the United States in 2004 and 2003.

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

	United States	Brazil	Worldwide
		(In millions)	
2004			
Future cash inflows(1)	$ 4,059	$ 810	$ 4,869
Future production costs	(1,087)	(76)	(1,163)
Future development costs	(544)	(236)	(780)
Future income tax expenses	(272)	(111)	(383)
Future net cash flows	2,156	387	2,543
10% annual discount for estimated timing of cash flows	(655)	(183)	(838)
Standardized measure of discounted future net cash flows	$ 1,501	$ 204	$ 1,705
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 1,388	$ 204	$ 1,592

(1) United States excludes $148 million, $139 million and $111 million of future net cash outflows attributable to hedging activities during 2004, 2003 and 2002.

	United States	Brazil	Worldwide
		(In millions)	
2003			
Future cash inflows[1]	$ 4,445	$ 588	$ 5,033
Future production costs	(967)	(65)	(1,032)
Future development costs	(564)	(236)	(800)
Future income tax expenses	(362)	(75)	(437)
Future net cash flows	2,552	212	2,764
10% annual discount for estimated timing of cash flows	(735)	(128)	(863)
Standardized measure of discounted future net cash flows	$ 1,817	$ 84	$ 1,901
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 1,729	$ 84	$ 1,813
2002			
Future cash inflows[1]	$ 4,632	$ —	$ 4,632
Future production costs	(1,071)	—	(1,071)
Future development costs	(623)	—	(623)
Future income tax expenses	(465)	—	(465)
Future net cash flows	2,473	—	2,473
10% annual discount for estimated timing of cash flows	(738)	—	(738)
Standardized measure of discounted future net cash flows	$ 1,735	$ —	$ 1,735
Standardized measure of discontinued future net cash flows, including effects of hedging activities	$ 1,671	$ —	$ 1,671

(1) United States excludes $148 million, $139 million and $111 million of future net cash outflows attributable to hedging activities during 2004, 2003 and 2002.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end 2004 prices of $6.22 per MMBtu for natural gas and $43.45 per barrel of oil. Adjustments for transportation and other charges resulted in a net price of $5.83 per Mcf of natural gas, $42.11 per Bbl of oil and $31.64 per Bbl of NGL. 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 worldwide standardized measure of discounted future net cash flows:

	Years Ended December 31,(1)(2)		
	2004	2003	2002
	(In millions)		
Sales and transfers of natural gas and oil produced net of production costs	$(567)	$(677)	$ (964)
Net changes in prices and production costs	159	598	1,888
Extensions, discoveries and improved recovery, less related costs	90	399	568
Changes in estimated future development costs	26	(24)	38
Previously estimated development costs incurred during the period	11	50	88
Revisions of previous quantity estimates	(122)	(118)	(367)
Accretion of discount	210	195	135
Net change in income taxes	31	19	(215)
Purchases of reserves in place	—	7	—
Sales of reserves in place	(11)	(336)	(1,122)
Changes in production rates, timing and other	(23)	53	332
Net change	$(196)	$ 166	$ 381

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

(2) Includes operations in the United States and Brazil.

SCHEDULE II

EL PASO CGP COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2004, 2003 and 2002

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
			(In millions)		
2004					
Allowance for doubtful accounts	$ 37	$ (8)	$ (8)[3]	$ 8	$ 29
Valuation allowance on deferred tax assets	1	24[1]	—	—	25
Legal reserves	27	7[7]	—	2	36
Environmental reserves	131	9	(18)[4]	6	128
Regulatory reserves	—	—	—	—	—
2003					
Allowance for doubtful accounts	$ 21	$ (1)	$ —	$ 17	$ 37
Valuation allowance on deferred tax assets	27	(26)[1]	—	—	1
Legal reserves	49	(3)	(16)[4]	(3)	27
Environmental reserves	62	12	(10)[4]	67[2]	131
Regulatory reserves	4	(3)	(1)[4]	—	—
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)[4]	(94)[6]	62
Regulatory reserves	5	7	(8)[4]	—	4

(1) Relates primarily to foreign impairments and ceiling test charges and net operating loss carryovers.
(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, environmental remediation reserves and rate settlement reserves.
(5) Relates to legal reserves previously embedded 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 13 for a further discussion of this change.

SIGNATURES

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

EL PASO CGP COMPANY

By: /s/ JEFFREY I. BEASON

Jeffrey I. Beason
Senior Vice President and Controller
(Principal Accounting Officer)

Dated: November 4, 2005