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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from to .

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑.

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑.

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 30, 2005 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $7,594,102,633.

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

Common Stock, par value $3 per share. Shares outstanding on February 24, 2006: 659,210,298

Documents Incorporated by Reference

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive proxy statement for the 2006 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2006.

EL PASO CORPORATION

TABLE OF CONTENTS

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

/d	= per day	MDth	= thousand dekatherms
Bbl	= barrel	MMBtu	= million British thermal units
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	MMWh	= thousand megawatt hours
LNG	= liquefied natural gas	MW	= megawatt
MBbls	= thousand barrels	NGL	= natural gas liquids
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units
Mcfe	= thousand cubic feet of natural gas equivalents	Tcfe	= trillion cubic feet of natural gas equivalents

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. 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", "the Company", or "El Paso", we are describing El Paso Corporation and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

Overview

We are an energy company, originally founded in 1928 in El Paso, Texas, with a stated purpose to provide natural gas and related energy products in a safe, efficient and dependable manner. Our long-term business strategy is focused on participating in the energy industry through a rate regulated natural gas transmission business in North America and a large, independent exploration and production business operating both domestically and internationally.

Natural Gas Transmission. We own North America's largest interstate pipeline system, which has approximately 55,500 miles of pipe that connect North America's major producing basins to its major consuming markets. We also own approximately 420 Bcf of storage capacity and an LNG import facility with 806 MMcf of daily base load sendout capacity.

Exploration and Production. Our exploration and production business is focused on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States and Brazil and related marketing activities. As of December 31, 2005, we held an estimated 2.4 Tcfe of proved natural gas and oil reserves in the United States and Brazil, exclusive of our equity share in the proved reserves of an unconsolidated affiliate of 253 Bcfe.

Other. We currently own or have owned other non-core assets acquired as part of a number of mergers and acquisitions and growth initiatives when we expanded from a regional gas pipeline company in the mid-1990's to an international energy company by early 2001. Since 2003, a substantial portion of these assets have been sold, have pending sales contracts or are in the process of being sold. The divestiture of these assets was targeted at improving our operating results, financial condition and liquidity, which were negatively impacted by the decline of the energy trading industry, bankruptcy of several energy industry participants and our credit downgrades.

Business Objective and Strategy

As of December 31, 2005, we conduct our core natural gas transmission and exploration and production operations through our Pipelines, Exploration and Production and Marketing and Trading segments. We also have Power and Field Services segments. Our business segments provide a variety of energy products and services and are managed separately as each segment requires different technology and marketing strategies. For further discussion of our business segments, see the information below and in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and assets, see Part II, Item 8, Financial Statements and Supplementary Data, Note 20, which is incorporated herein by reference. Our business strategy in each of our operating segments can be summarized as follows:

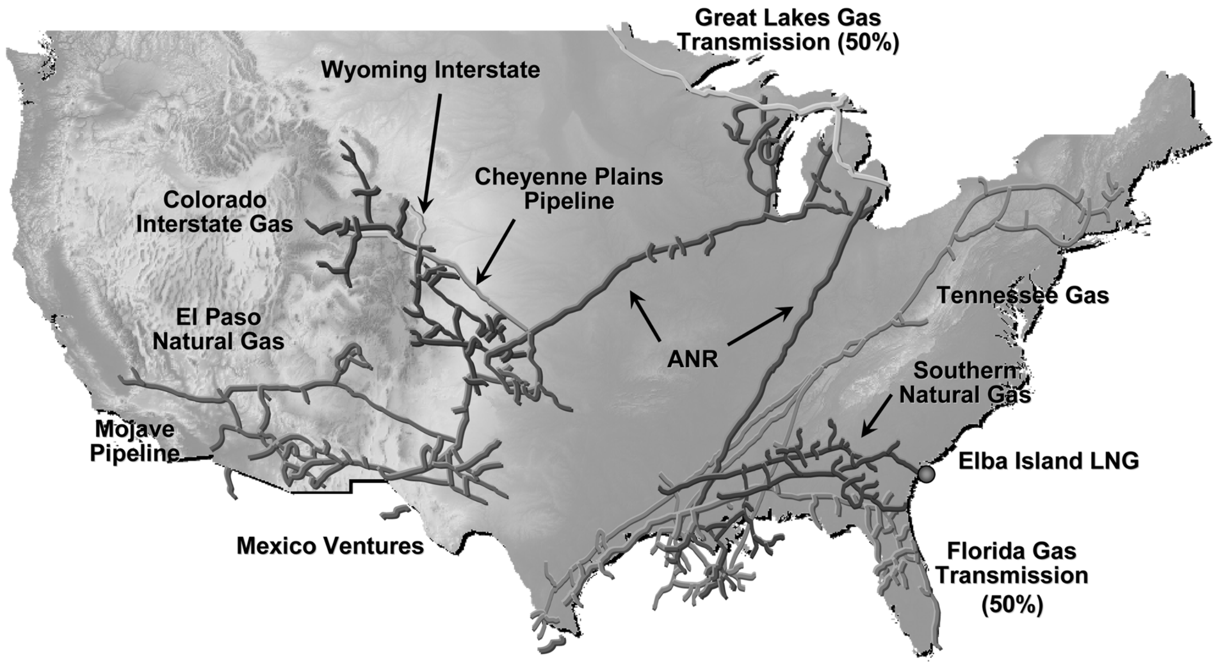
Pipelines	Enhancing the value of our transmission business through successful recontracting, continuous efficiency improvements through cost management and prudent capital spending in the United States and Mexico, while providing outstanding customer service through safe operations.
Exploration and Production	Growing our reserve base in a manner that creates shareholder value through disciplined capital allocation, cost control and portfolio management.
Marketing and Trading	Marketing our natural gas and oil production at optimal prices and managing associated price risks.

The assets remaining in our Power segment are used to serve customers under long-term power sales contracts or sell power to the open market in spot market transactions. Additionally, through the remaining assets in our Field Services segment, we provide processing and gathering services through two facilities that support our Rocky Mountain production activities.

Pipelines Segment

Our Pipelines segment provides natural gas transmission and related services through eight separate, wholly owned pipeline systems and four 50 percent owned systems that, combined, own or have interests in approximately 55,500 miles of interstate natural gas pipelines, representing the largest integrated natural gas transmission system in the United States. Our system connects the nation's principal natural gas supply regions to the six largest consuming regions in the United States: the Gulf Coast, California, the northeast, the midwest, the southwest and the southeast. Our pipeline operations include access to systems in Canada and assets in Mexico. The size, connectivity and diversity of our U.S. pipeline system provides growth opportunities through infrastructure development or large scale expansion projects and gives us the capability to adapt to the dynamics of shifting supply and demand.

We also own or have interests in approximately 420 Bcf of storage capacity through our wholly owned transmission systems and two wholly owned and three partially owned storage systems used to provide a variety of flexible services to our customers. We also have one LNG receiving terminal and related facilities at Elba Island, Georgia.



Each of our U.S. pipeline systems and storage facilities operate under Federal Energy Regulatory Commission (FERC) approved tariffs that establish rates, cost recovery mechanisms, terms and conditions of service to our customers. 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, LNG terminalling and related services consist of two types of revenues:

Reservation revenues. Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline system, storage facilities or LNG terminalling 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. Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn.

In 2005, approximately 79 percent of our revenues were attributable to reservation charges paid by firm customers. The remaining 21 percent of our revenues were variable. Because of 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 changes in natural gas prices and market conditions, regulatory actions, competition, weather and the creditworthiness of our customers. We also experience volatility when the amounts of natural gas utilized in our operations differ from the amounts we recover from our customers for that purpose.

Our strategy is to enhance the value of our transmission business through:

- Seeking to expand our systems by attracting new customers, markets or supply sources while leveraging our existing assets to the extent possible;
- Recontracting or contracting available or expiring capacity and resolving open rate cases;
- Focusing on efficiency in our operations and cost control, including efficiencies that may be available across our systems or due to the coast-to-coast scale of our operations;
- Investing in maintenance and pipeline integrity projects to maintain the value and ensure the safety of our pipeline systems and assets;
- Providing outstanding customer service; and
- Providing natural gas transmission and related services through safe operations.

Wholly Owned Interstate Transmission Systems

Below is a further discussion of our wholly owned pipeline systems.

Transmission System	Supply and Market Region	As of December 31, 2005 Miles of Pipeline	Design Capacity	Storage Capacity	Average Throughput[1] 2005	2004	2003
			(MMcf/d)	(Bcf)		(BBtu/d)	
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.	14,100	6,876	90	4,443	4,469	4,710
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,500	6,775	192	4,100	4,067	4,232
El Paso Natural Gas (EPNG)	Extends from the San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	10,700	5,650[2]	—[3]	4,053	4,074	3,874
Southern Natural Gas (SNG)	Extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham.	7,700	3,450	60	1,984	2,163	2,101
Colorado Interstate Gas (CIG)	Extends from production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnections with pipeline systems transporting gas to the midwest, the southwest, California and the Pacific northwest.	4,000	3,000	29	1,902	1,744	1,685

		As of December 31, 2005			Average Throughput[1]		
Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity	Storage Capacity	2005	2004	2003
			(MMcf/d)	(Bcf)		(BBtu/d)	
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,997	—	1,479	1,201	1,213
Mojave Pipeline (MPC)	Connects with the EPNG system near Cadiz, California, the EPNG and Transwestern systems at Topock, Arizona and to the Kern River Gas Transmission Company system in California. This system also extends to customers in the vicinity of Bakersfield, California.	400	407	—	161	161	192
Cheyenne Plains Gas Pipeline (CPG)	Extends from the Cheyenne hub in Colorado to various pipeline interconnections near Greensburg, Kansas.	400	757	—	433	89	—

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.

(3) Effective January 1, 2006, EPNG began offering interruptible storage service from a storage facility that has a maximum working capacity of up to approximately 44 Bcf.

We also have a number of pipeline expansion projects underway as of December 31, 2005, which are in various stages of certification and approval. Below are the more significant projects that have been approved by the FERC:

Project	Capacity (MMcf/d)	Description	Anticipated Completion Date
ANR			
Wisconsin 2006 expansion	164	To construct and operate a 3.8 mile, 30-inch pipeline extension of the Madison Lateral Loop, a 3.1 mile, 16-inch pipeline loop[(1)] of the Little Chute Lateral in Outagamie County, a 20,620 horsepower compressor station, a 2,370 horsepower compressor unit at the Janesville compressor station, and upgrades of five existing meter stations in various counties in Wisconsin.	November 2006
TGP			
Triple-T expansion	200	To construct 6.2 miles of 24-inch pipeline to extend its existing 30-inch Triple-T Line, beginning in Eugene Island Block 349, to interconnect with Enterprise Products Partners' Anaconda System on the EI 371 platform, as well as associated piping and other appurtenant facilities.	August 2006
Northeast ConneXion-NY/NJ	49	To modify an existing dehydration tower, filed jointly with National Fuel, serving the Hebron Storage Field in Potter County, Pennsylvania, expand capacity on Line 300, located in Bradford and Susquehanna Counties, Pennsylvania by building 6 miles of loop[(1)] line, add compression facilities at Compressor Station 313 in Potter County, Pennsylvania, and at Station 317 in Bradford County, Pennsylvania, upgrade Ramsey Meter Station in Bergen County, New Jersey, and use additional incremental capacity resulting from the replacement of compression facilities at Station 325 in Sussex County, New Jersey.	November 2006
Louisiana Deepwater Link	850	To construct a 300 foot extension of its 20-inch Grand Isle supply lateral, construct 2,100 feet of 24-inch West Delta supply lateral, abandon 3,100 feet of the 20-inch line connected to the Grand Isle platform, and install appurtenant facilities on Enterprise's Independence Hub platform located in Mississippi Canyon Block 920.	October 2006
WIC			
Piceance Basin expansion	333	To construct and operate approximately 142 miles of 24-inch pipeline, compression and metering facilities to move additional supplies into the WIC system.	March 2006

(1) A loop 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 Systems

Transmission System[1]	Supply and Market Region	As of December 31, 2005			Average Throughput[2]		
		Ownership Interest	Miles of Pipeline[2]	Design Capacity[2]	2005	2004	2003
		(Percent)		(MMcf/d)	(BBtu/d)		
Florida Gas Transmission[3]	Extends from south Texas to south Florida.	50	4,867	2,090	1,916	2,014	1,963
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,500	2,376	2,200	2,366
Samalayuca Pipeline and Gloria a Dios Compression Station	Extends from U.S.-Mexico border to the State of Chihuahua, Mexico.	50	23	460	423	433	409
San Fernando Pipeline	Extends from Pemex Compression Station 19 to the Pemex metering station in San Fernando, Mexico in the State of Tamaulipas.	50	71	1,000	951	951	130

(1) These systems are accounted for as equity investments.

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

(3) We have a 50 percent equity interest in Citrus Corporation, which owns this system.

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, 2005		Location
	Ownership Interest	Storage Capacity[1]	
	(Percent)	(Bcf)	
Bear Creek Storage	100	58	Louisiana
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 133 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, 2005.

LNG Facility

In addition to our pipeline systems and storage facilities, we own an LNG receiving terminal located on Elba Island, near Savannah, Georgia. The recently completed expansion of the Elba Island facility increased the peak sendout capacity to 1,215 MMcf/d and the base load sendout capacity to 806 MMcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

Markets and Competition

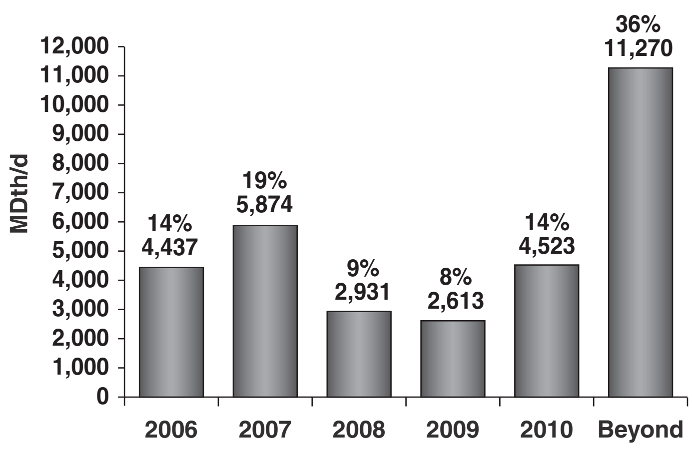
We provide natural gas services to a variety of customers, including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear and hydroelectric power 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 their delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. However, 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 of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power. This effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and electric transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with pipelines.

Our existing contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or remarket expiring capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the 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. The table below shows the contracted capacity that expires by year over the next five years and thereafter.

Contract Expirations



The following table details the markets we serve and the competition faced by each of our wholly owned pipeline transmission systems as of December 31, 2005:

TGP

Customer Information	Contract Information	Competition
Approximately 466 firm and interruptible customers, none of which individually represents more than 10 percent of revenues	Approximately 481 firm transportation contracts. Weighted average remaining contract term of approximately five years.	TGP faces strong competition in the northeast, Appalachian, midwest and southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and from the Canadian border. In the offshore areas of the Gulf of Mexico, factors such as the distance of the supply fields from the pipeline, relative basis pricing of the pipeline receipt points, and costs of intermediate gathering or required processing of the natural gas to be transported may influence determinations of whether natural gas is ultimately attached to our system.

ANR

Customer Information	Contract Information	Competition
Approximately 297 firm and interruptible customers Major Customer: We Energies (829 BBtu/d)	Approximately 634 firm transportation contracts. Weighted average remaining contract term of approximately five years. Contract terms expire in 2006-2010.	ANR's principal markets are in the midwest where it competes with other interstate and intrastate pipeline companies and local distribution companies to provide natural gas transportation and storage services. ANR 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 other interstate pipelines in the midwest market to serve electric generation and local distribution companies. 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 Wisconsin and the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.

EPNG

Customer Information	Contract Information	Competition
Approximately 163 firm and interruptible customers	Approximately 251 firm transportation contracts. Weighted average remaining contract term of approximately four years.	EPNG faces competition in the west and southwest from other existing and proposed pipelines, from California storage facilities, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear, coal and fuel oil. In addition, initiatives to bring LNG into California and northern Mexico are underway.
Major Customers:		
Southern California Gas Company		
(453 BBtu/d)	Contract term expires in 2006.	
(93 BBtu/d)	Contract term expire in 2007.	
(768 BBtu/d)	Contract terms expire in 2009-2011.	
Southwest Gas Corporation		
(12 BBtu/d)	Contract term expires in 2006.	
(470 BBtu/d)	Contract term expires in 2011.	
(74 BBtu/d)	Contract term expires in 2015.	

SNG

Customer Information	Contract Information	Competition
Approximately 225 firm and interruptible customers	Approximately 181 firm transportation contracts. Weighted average remaining contract term of approximately six years.	SNG faces strong competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on our system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. SNG's four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of their other customers. In addition, SNG competes with pipelines and gathering systems for connection to new supply services.
Major Customers:		
Atlanta Gas Light Company		
(959 BBtu/d)	Contract terms expire in 2008-2015.	
Southern Company Services		
(418 BBtu/d)	Contract terms expire in 2010-2018.	
Alabama Gas Corporation		
(415 BBtu/d)	Contract terms expire in 2006-2013.	
Scana Corporation		
(346 BBtu/d)	Contract terms expire in 2006-2019.	

CIG

Customer Information	Contract Information	Competition
Approximately 111 firm and interruptible customers	Approximately 184 firm transportation contracts. Weighted average remaining contract term of approximately five years.	CIG serves two major markets. Its "on-system" market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its "off-system" market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the midwest, the southwest, California and the Pacific northwest. Competition for its on-system market consists of an intrastate pipeline, local production from the Denver-Julesburg basin, 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 existing and proposed interstate pipelines that are directly connected to its supply sources.
Major Customer:		
Public Service Company of Colorado		
(970 BBtu/d)	Contract terms expire in 2007.	
(187 BBtu/d)	Contract term expires in 2008.	
(261 BBtu/d)	Contract terms expires in 2009-2014.	

WIC

Customer Information	Contract Information	Competition
Approximately 47 firm and interruptible customers	Approximately 47 firm transportation contracts. Weighted average remaining contract term of approximately six years.	WIC competes with pipelines that are existing, proposed and currently under construction to provide transportation services to delivery points in northeast Colorado and western Wyoming. 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.
Major Customers:		
Williams Power Company (353 BBtu/d)	Contract terms expire in 2008-2013.	
CIG (247 BBtu/d)	Contract terms expire in 2006-2016.	
Western Gas Resources (235 BBtu/d)	Contract terms expire in 2007-2013.	
Cantera Gas Company (226 BBtu/d)	Contract terms expire in 2012-2013.	

MPC

Customer Information	Contract Information	Competition
Approximately 13 firm and interruptible customers	Approximately six firm transportation contracts. Weighted average remaining contract term of approximately eight years.	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear, coal and fuel oil. In addition, initiatives to bring LNG into California and northern Mexico are underway.
Major Customers:		
EPNG (312 BBtu/d)	Contract term expires in 2015.	
Los Angeles Department of Water and Power (50 BBtu/d)	Contract term expires in 2007.	

CPG

Customer Information	Contract Information	Competition
Approximately 20 firm and interruptible customers	Approximately 16 firm transportation contracts Weighted average remaining contract term of approximately nine years.	CPG competes directly with other interstate pipelines serving the mid-continent region. Indirectly, CPG competes with other existing and proposed interstate pipelines that transport Rocky Mountain gas to other markets.
Major Customers:		
Oneok Energy Services Company L.P. (195 BBtu/d)	Contract terms expire in 2015.	
Anadarko Energy Service Company (112 BBtu/d)	Contract terms expire in 2015-2016.	
Encana Marketing (USA) Inc. (170 BBtu/d)	Contract term expires in 2015.	
Kerr McGee (83 BBtu/d)	Contract terms expire in 2015.	

Exploration and Production Segment

Our Exploration and Production segment's long-term business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States and internationally. As of December 31, 2005, we controlled over 3 million net leasehold acres. During 2005, daily equivalent natural gas production averaged approximately 743 MMcfe/d and our proved natural gas and oil reserves at December 31, 2005, were approximately 2.4 Tcfe, excluding amounts related to our unconsolidated investment in Four Star Oil & Gas Company (Four Star).

Our consolidated operations are divided into the following regions:

Region	Operating Areas/Basins
United States	
Onshore	East Texas and North Louisiana Rocky Mountains Black Warrior Arkoma Raton Illinois
Texas Gulf Coast	South Texas
Gulf of Mexico and south Louisiana	Gulf of Mexico (Federal and State waters) South Louisiana
Internationally	
Brazil	Camamu, Santos, Espirito Santo and Potiguar

In addition to our consolidated operations, we own a 43.1 percent interest in Four Star, which was acquired in connection with our acquisition of Medicine Bow Energy Corporation (Medicine Bow). Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and the Gulf of Mexico. During 2005, our proportionate share of Four Star's daily equivalent natural gas production averaged approximately 24 MMcfe/d and at December 31, 2005, proved natural gas and oil reserves, net to our interest, were 253 Bcfe.

Our business strategy has been to create value through our drilling activities and through acquisitions of assets and companies. For 2006, we expect our growth to occur principally through drilling activities. However, we believe strategic acquisitions can support our corporate objectives by:

- Re-shaping our portfolio toward longer-lived, shallower decline rate reserves;
- Leveraging operational expertise we already possess in key operating areas, geologies or techniques;
- Balancing our exposure to regions, basins and commodities;
- Achieving risk-adjusted returns competitive with those available within our existing inventory; and
- Increasing our reserves more rapidly by supplementing drilling activities.

Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The tables below present our estimated proved reserves as of December 31, 2005 and our 2005 production by region and summarizes our estimated proved reserves by classification as of December 31, 2005:

	Net Proved Reserves[(1)]					
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	Total (Percent)	2005 Production (MMcfe)
Reserves and Production by Region						
United States[(2)]						
Onshore	1,258,329	32,007	1,207	1,457,615	60%	109,361
Texas Gulf Coast	392,783	2,765	9,702	467,580	20%	77,014
Gulf of Mexico and south Louisiana	179,654	8,456	1,653	240,311	10%	65,432
Total United States	1,830,766	43,228	12,562	2,165,506	90%	251,807
Brazil	56,388	32,250	—	249,890	10%	19,300
Total	1,887,154	75,478	12,562	2,415,396	100%	271,107
Unconsolidated investment in Four Star[(3)(4)]	192,895	3,349	6,668	252,996	100%	8,844
Reserves by Classification						
United States[(2)]						
Producing	1,175,838	19,831	9,503	1,351,841	63%	
Non-Producing	228,173	8,750	1,507	289,716	13%	
Undeveloped	426,755	14,647	1,552	523,949	24%	
Total proved	1,830,766	43,228	12,562	2,165,506	100%	
Brazil						
Producing	17,260	632	—	21,052	9%	
Non-Producing	10,162	512	—	13,234	5%	
Undeveloped	28,966	31,106	—	215,604	86%	
Total proved	56,388	32,250	—	249,890	100%	
Worldwide						
Producing	1,193,098	20,463	9,503	1,372,893	57%	
Non-Producing	238,335	9,262	1,507	302,950	12%	
Undeveloped	455,721	45,753	1,552	739,553	31%	
Total proved	1,887,154	75,478	12,562	2,415,396	100%	
Unconsolidated investment in Four Star[(3)]						
Producing	154,979	3,246	5,371	206,677	82%	
Non-Producing	3,105	20	28	3,395	1%	
Undeveloped	34,811	83	1,269	42,924	17%	
Total Four Star	192,895	3,349	6,668	252,996	100%	

(1) Net proved reserves exclude our Power segment's equity interests in proved reserves in Indonesia and in Peru of 162,254 MMcf of natural gas and 2,058 MBbls of oil, condensate and NGL for total natural gas equivalents of 174,600 MMcfe, all net to our ownership interests. Our Power segment has completed or expects to complete the sale of these equity interests in 2006.

(2) 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.

(3) Our share of Four Star's proved reserves has been estimated based on an evaluation of those reserves by El Paso's internal reservoir engineers and not by engineers of Four Star. An independent reservoir engineering firm, Ryder Scott, which was engaged by us, prepared an estimate on 86 percent of Four Star's proved reserves. Based on the amount of Four Star's proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable.

(4) Represents our proportionate share of Four Star's production since the acquisition date.

Consolidated reserve information in the tables above is based on our internal reserve report. Ryder Scott, an independent petroleum engineering firm that reports to the Audit Committee of our Board of Directors, prepared an estimate on 92 percent of our natural gas and oil reserves. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. 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.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production costs, and projecting the timing of development expenditures, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based, and on 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.

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. 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. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreage and Wells

Our properties are primarily in the United States and are separated into the Onshore, Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. We also have properties internationally in Brazil. The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2005, (ii) our interest in natural gas and oil wells at December 31, 2005 and (iii) our exploratory and development wells drilled during the years 2003 through 2005. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

Acreage	Developed		Undeveloped		Total	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
United States						
Onshore	867,392	518,892	1,591,543	1,216,552	2,458,935	1,735,444
Texas Gulf Coast	103,234	79,439	151,751	109,241	254,985	188,680
Gulf of Mexico and south Louisiana	530,464	362,938	540,972	494,481	1,071,436	857,419
Total	1,501,090	961,269	2,284,266	1,820,274	3,785,356	2,781,543
Brazil	49,262	17,242	1,157,268	346,788	1,206,530	364,030
Worldwide Total	1,550,352	978,511	3,441,534	2,167,062	4,991,886	3,145,573

In the United States, our net developed acreage is concentrated primarily in the Gulf of Mexico (38 percent), Utah (12 percent), Texas (10 percent), Oklahoma (9 percent), Alabama (8 percent), New Mexico (8 percent) and Louisiana (6 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (27 percent), the Gulf of Mexico (22 percent), Wyoming (10 percent), Louisiana (7 percent), Texas (7 percent), West Virginia (7 percent), Indiana (6 percent) and Alabama (5 percent). Approximately 14 percent, 13 percent and 10 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2006, 2007 and 2008. Approximately 24 percent, 21 percent and 14 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2006, 2007 and 2008.

Productive Wells	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled at December 31, 2005	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2][3]	Gross[1]	Net[2]
United States								
Onshore	3,424	2,614	514	363	3,938	2,977	36	29
Texas Gulf Coast	831	702	—	—	831	702	—	—
Gulf of Mexico and south Louisiana	175	115	53	35	228	150	4	1
Total United States	4,430	3,431	567	398	4,997	3,829	40	30
Brazil	4	3	6	5	10	8	—	—
Worldwide Total	4,434	3,434	573	403	5,007	3,837	40	30

Wells Drilled	Net Exploratory Wells Drilled[2]			Net Development Wells Drilled[2]		
	2005	2004	2003	2005	2004	2003
United States						
Productive	86	13	54	279	298	272
Dry	2	10	22	4	3	1
Total	88	23	76	283	301	273
Brazil						
Productive	—	—	2	—	—	—
Dry	—	1	4	—	—	—
Total	—	1	6	—	—	—
Worldwide						
Productive	86	13	56	279	298	272
Dry	2	11	26	4	3	1
Total	88	24	82	283	301	273

(1) Gross interest reflects the total acreage or wells we participated in, regardless of our ownership interest in the acreage or wells.

(2) Net interest is the aggregate of the fractional working interests that we have in the gross acreage, gross wells or gross drilled wells.

(3) At December 31, 2005, we operated 3,541 of the 3,841 net productive wells.

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

Net Production, Sales Prices, Transportation and Production Costs

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

	2005	2004	2003
Net Production Volumes			
United States			
Natural gas (MMcf)	206,714	238,009	338,762
Oil, condensate and NGL (MBbls)	7,516	8,498	11,778
Total (MMcfe)	251,807	288,994	409,432
Brazil			
Natural gas (MMcf)	15,578	6,848	—
Oil, condensate and NGL (MBbls)	620	320	—
Total (MMcfe)	19,300	8,772	—
Worldwide			
Natural gas (MMcf)	222,292	244,857	338,762
Oil, condensate and NGL (MBbls)	8,136	8,818	11,778
Total (MMcfe)	271,107	297,766	409,432
Natural Gas Average Realized Sales Price ($/Mcf) [(1)]			
United States			
Excluding hedges	$ 7.92	$ 6.02	$ 5.51
Including hedges	$ 6.69	$ 5.94	$ 5.40
Brazil			
Excluding hedges	$ 2.33	$ 2.01	$ —
Including hedges	$ 2.33	$ 2.01	$ —
Worldwide			
Excluding hedges	$ 7.53	$ 5.90	$ 5.51
Including hedges	$ 6.39	$ 5.83	$ 5.40
Oil, Condensate, and NGL Average Realized Sales Price ($/Bbl) [(1)]			
United States			
Excluding hedges	$ 45.86	$ 34.44	$ 26.64
Including hedges	$ 45.86	$ 34.44	$ 25.96
Brazil			
Excluding hedges	$ 53.42	$ 43.01	$ —
Including hedges	$ 42.42	$ 39.19	$ —
Worldwide			
Excluding hedges	$ 46.43	$ 34.75	$ 26.64
Including hedges	$ 45.60	$ 34.61	$ 25.96
Average Transportation Cost			
United States			
Natural gas ($/Mcf)	$ 0.20	$ 0.17	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 0.69	$ 1.16	$ 1.05
Worldwide			
Natural gas ($/Mcf)	$ 0.18	$ 0.17	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 0.63	$ 1.12	$ 1.05

	2005	2004	2003
Average Production Cost ($/Mcfe)[2]			
United States			
Average lease operating cost	$ 0.73	$ 0.62	$ 0.42
Average production taxes	0.27	0.11	0.14
Total production cost	$ 1.00	$ 0.73	$ 0.56
Brazil			
Average lease operating cost	$ 0.42	$ —	$ —
Worldwide			
Average lease operating cost	$ 0.72	$ 0.60	$ 0.42
Average production taxes	0.24	0.11	0.14
Total production cost	$ 0.96	$ 0.71	$ 0.56

(1) Prices are stated before transportation costs.

(2) 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:

	2005	2004	2003
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 643	$ 33	$ 10
Unproved	143	32	35
Development Costs	503	395	668
Exploration Costs:			
Delay rentals	3	7	6
Seismic acquisition and reprocessing	7	29	56
Drilling	133	149	405
Asset Retirement Obligations[1]	1	30	124
Total full cost pool expenditures	1,433	675	1,304
Non-full cost pool expenditures	22	11	17
Total cost incurred[2]	$1,455	$ 686	$1,321
Acquisition of unconsolidated investment in Four Star[2]	$ 769	$ —	$ —
Brazil and Other International			
Acquisition Costs:			
Proved	$ 8	$ 69	$ —
Unproved	1	3	4
Development Costs	6	1	—
Exploration Costs:			
Seismic acquisition and reprocessing	7	15	11
Drilling	8	10	84
Asset Retirement Obligations	—	3	—
Total full cost pool expenditures	30	101	99
Non-full cost pool expenditures	—	3	1
Total cost incurred	$ 30	$ 104	$ 100

	2005	2004	2003
		(In millions)	
Worldwide			
Acquisition Costs:			
Proved	$ 651	$ 102	$ 10
Unproved	144	35	39
Development Costs	509	396	668
Exploration Costs:			
Delay rentals	3	7	6
Seismic acquisition and reprocessing	14	44	67
Drilling	141	159	489
Asset Retirement Obligations(1)	1	33	124
Total full cost pool expenditures	1,463	776	1,403
Non-full cost pool expenditures	22	14	18
Total cost incurred(2)	$1,485	$ 790	$1,421
Acquisition of unconsolidated investment in Four Star(2)	$ 769	$ —	$ —

(1) Includes an increase to our property, plant and equipment of approximately $114 million in 2003 associated with our adoption of Statement of Financial Accounting Standards (SFAS) No. 143.

(2) Includes $179 million of deferred income tax adjustments related to the acquisition of full-cost pool properties and $217 million related to the acquisition of our unconsolidated investment in Four Star.

We spent approximately $247 million in 2005, $156 million in 2004, and $220 million in 2003 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

Markets and Competition

We primarily sell our domestic natural gas and oil to third parties through our Marketing and Trading segment at spot market prices, subject to customary adjustments. As part of our long-term business strategy, we will continue this practice. We sell our NGL at market prices under monthly or long-term contracts, subject to customary adjustments. In Brazil, we sell the majority of our natural gas and oil to Petrobras, a Brazilian energy company. We also engage in hedging activities on a portion of our production to stabilize our cash flows and to reduce the risk of downward commodity price movements on sales of our production. As of December 31, 2005, in this segment we had hedged approximately 85,000 BBtu of our anticipated natural gas production in 2006 and approximately 26,000 BBtu of our anticipated natural gas production during 2007 through 2012. For a further discussion of the prices at which we have hedged our natural gas and oil production, see Part II, Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations.

The exploration and production business is highly competitive in the search for and acquisition of additional natural gas and oil reserves and in the sale of natural gas, oil and NGL. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms, our ability to access drilling and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in the exploration and production business will be dependent on our ability to find or acquire additional reserves at costs that yield acceptable returns on the capital invested.

Marketing and Trading Segment

Our Marketing and Trading segment's primary focus is to market our Exploration and Production segment's natural gas and oil production and to manage the company's price risks related to its anticipated production, primarily through the use of natural gas and oil derivative contracts. In addition, we also continue to manage and liquidate various transportation, power and other contracts remaining from our legacy trading operations, primarily entered into prior to the deterioration of the energy trading environment in 2002. We enter into contracts in this segment with both third parties and with affiliates that require physical delivery of a commodity or financial settlement which are further described below.

Production-related Natural Gas and Oil Derivatives

Our natural gas and oil contracts include options and swaps designed to provide price protection to El Paso from fluctuations in natural gas and oil prices. As of December 31, 2005, these contracts provided El Paso with floor prices, ceiling prices and fixed prices on the following volumes of future natural gas and oil production:

	2006	2007	2008	2009
Natural Gas (TBtu)				
Volumes with floor price	120	51	18	17
Volumes with ceiling price	60	21	18	17
Volumes with fixed prices	25	—	—	—
Oil (MBbls)				
Volumes with floor and ceiling prices	—	1,009	930	—
Volumes with fixed prices	1,044	—	—	—

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. We typically refer to the fixed reservation cost as a demand charge. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of working capital needed to use this capacity and the capacity required to meet our other long-term obligations. The following table details our transportation contracts as of December 31 2005:

	Alliance Pipeline	Enterprise Texas Pipeline	Other Pipelines
Daily capacity (MMBtu/d)	160,000	435,000	918,000[(1)]
Expiration	2015	May 2006	2006 to 2028
Receipt points	AECO Canada	South Texas	Various
Delivery points	Chicago	Houston Ship Channel	Various

(1) Approximately 700,000 MMBtu/d of this capacity is contracted with our pipeline affiliates.

Other natural gas derivative contracts. As of December 31, 2005, we have eight significant physical natural gas contracts with power plants associated with our legacy trading operations. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2009 to 2028, with expected obligations under individual contracts with third parties ranging from 32,000 to 142,000 MMBtu/d.

Power contracts. As of December 31, 2005, we held derivative contracts with Constellation Energy Commodities Group (Constellation) that swap locational differences in power prices between the Pennsylvania-New Jersey-Maryland (PJM) eastern region with those in the west PJM hub through 2013.

We also held a number of other power contracts that obligate us to supply power or manage the price risk associated with those supply contracts. These include a power supply agreement associated with our formerly-owned Utility Contract Funding (UCF) facility for approximately 1,700 MMWh per year through 2016. During 2005, we entered into contracts that substantially offset the commodity risk associated with these power supply and power price risk management contracts. We will terminate or assign a portion of these contracts to Morgan Stanley in 2006; however, we will retain some contracts (including those related to UCF) that will expose us primarily to locational price risk in the future as any fixed price exposure is largely offset by the new contracts we entered into in 2005.

Markets and Competition

Our Marketing and Trading segment operates in a highly competitive environment, competing on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served is influenced directly or indirectly by energy market economics. Our primary competitors include:

- Affiliates of major oil and natural gas producers;
- Large domestic and foreign utility companies;
- Affiliates of large local distribution companies;
- Affiliates of other interstate and intrastate pipelines; and
- Independent energy marketers and power producers with varying scopes of operations and financial resources.

Power Segment

Our Power segment includes the ownership and operation of our remaining international and domestic power generation facilities. A number of our power assets have either been sold or are under sales agreements that are expected to close in the first half of 2006. These facilities primarily sell power under long-term power purchase agreements with power transmission and distribution companies owned by local governments which subject us to certain political risks. As of December 31, 2005, we owned or had interests in 23 power facilities in 11 countries with a total generating capacity of approximately 6,334 gross MW (only significant assets and investments are listed):

Project[(1)]	Area	El Paso Ownership Interest	Gross Capacity	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
		(Percent)	(MW)			
International						
Brazil						
Araucaria[(2)]	Brazil	60	484	COPEL	—	Natural Gas
Macae[(2)]	Brazil	100	928	Petrobras	2007	Natural Gas
Manaus[(3)]	Brazil	100	238	Manaus Energia	2008	Oil
Porto Velho	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro[(3)]	Brazil	100	158	Manaus Energia	2008	Oil
Asia[(4)]						
Fauji	Pakistan	42	157	Pakistan Water and Power	2029	Natural Gas
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Sengkang	Indonesia	48	135	PLN	2022	Natural Gas
Central and other South America[(4)]						
Aguaytia	Peru	24	155	Various	2005, 2006	Natural Gas
CEPP	Dominican Republic	48	67	CDEEE, Spot Market	2014	Oil
Fortuna	Panama	25	300	Union Fenosa	2005, 2008	Hydroelectric
Itabo	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Europe						
EMA[(4)]	Hungary	50	69	Dunaferr Energy Services	2016	Natural Gas/Oil
Domestic						
Berkshire	MA - U.S.	56	261	—[(5)]	—[(5)]	Natural Gas
Midland Cogeneration	MI - U.S.	44	1,575	Consumers Power, Dow	2025	Natural Gas

(1) Our Macae project in Brazil is consolidated. All others in this table are reflected as investments in unconsolidated affiliates in our financial statements.
(2) See Part II, Item 8, Financial Statements and Supplementary Data, Note 16 for a further discussion of these plants.
(3) See Part II, Item 8, Financial Statements and Supplementary Data, Note 21 for a further discussion of the transfer of ownership in 2008 of these facilities.
(4) We have sold or have received approval from our Board of Directors to sell these facilities in 2006.
(5) Our Marketing and Trading segment sells the power that this facility generates to the wholesale power market.

In addition to the international power plants above, our Power segment also has investments in the following international pipelines:

Pipeline	El Paso Ownership Interest	Miles of Pipeline	Design Capacity[(1)]	Average 2005 Throughput[(1)]
	(Percent)		(MMcf/d)	(BBtu/d)
Bolivia to Brazil	8	1,957	1,059	841
Argentina to Chile	22	336	138	100

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

Field Services Segment

As of December 31, 2005, our Field Services segment conducted our remaining midstream activities, which consisted principally of two processing plants that support our Exploration and Production segment activities in the Rocky Mountain area. These facilities had operational capacity of 49 MMcf/d. In January 2006, these plants were transferred to our Exploration and Production segment. As a result, our Field Services segment will cease to be a business segment in 2006.

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. Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, including those related to petroleum ship charters, all of which were insignificant to our results in 2005. Our discontinued operations consist of our south Louisiana gathering and processing assets (previously part of the Field Services segment), certain of our international power operations in Central America and Asia, certain of our international natural gas and oil production operations (primarily in Canada), our petroleum markets business and our coal mining operations.

Regulatory Environment

Pipelines. Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Each of our pipeline systems and storage facilities operates under tariffs approved by the FERC that establish rates, cost recovery mechanisms, and terms and conditions for service to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage, LNG terminalling 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.

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations by the U.S. Department of Transportation, U.S. Department of the Interior, and U.S. Coast Guard. Our systems have ongoing programs designed to keep our facilities in compliance with these safety and environmental requirements.

Exploration and Production. Our natural gas and oil exploration and production activities are regulated at the federal, state and local levels, as well as in Brazil. 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 Brazilian oil and natural gas operations are subject to environmental regulations administered by the Brazilian government, which includes political subdivisions in that country. 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. In addition, we maintain insurance to limit exposure to sudden and accidental spills and oil pollution liability.

International and Domestic Power. Our remaining international power generation activities are regulated by governmental agencies in the countries in which these projects are located. Many of these countries have 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.

Our remaining 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. Power production activities at these plants are regulated by the FERC under the Public Utility Regulatory Policies Act of 1978 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.

Field Services. Our remaining operations 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.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, and is incorporated herein by reference.

Employees

As of February 24, 2006, we had approximately 5,700 full-time employees, of which 310 employees are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of February 27, 2006, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso	2003	46
D. Mark Leland	Executive Vice President and Chief Financial Officer of El Paso	2005	44
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	49
Lisa A. Stewart	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2004	48
Susan B. Ortenstone	Senior Vice President (Human Resources and Administration) of El Paso	2003	49
Stephen C. Beasley	President of Eastern Pipeline Group	2005	54
James J. Cleary	President of Western Pipeline Group	2005	51
James C. Yardley	President of Southern Pipeline Group	2005	54
Daniel B. Martin	Senior Vice President of Pipeline Operations	2005	49

Douglas L. Foshee has been President, Chief Executive Officer, and a Director of El Paso since September 2003. Mr. Foshee became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. In December 2003, several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, filed for bankruptcy protection, whereby the subsidiaries jointly resolved their asbestos claims. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer, and Chairman of the

Board at Nuevo Energy Company. From 1993 to 1997, Mr. Foshee worked at Torch Energy Advisors Inc. in various capacities, including Chief Operating Officer and Chief Executive Officer.

D. Mark Leland has been Executive Vice President and Chief Financial Officer of El Paso since August 2005. Mr. Leland served as Executive Vice President of El Paso Exploration & Production Company (formerly known as El Paso Production Holding Company) from January 2004 to August 2005, and also as Chief Financial Officer and a director from April 2004 to August 2005. He served in various capacities for GulfTerra Energy Partners, L.P. and its general partner, including as Senior Vice President and Chief Operating Officer from January 2003 to December 2003, as Senior Vice President and Controller from July 2000 to January 2003, and as Vice President from August 1998 to July 2000. Mr. Leland has also worked in various capacities for El Paso Field Services from 1997 to August 2005.

Robert W. Baker has been Executive Vice President and General Counsel of El Paso since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. He was Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time he worked in various capacities in the legal department of Tenneco Energy and El Paso since 1983.

Lisa A. Stewart has been an Executive Vice President of El Paso since November 2004, and President of El Paso Exploration & Production Company since February 2004. Ms. Stewart was Executive Vice President of Business Development and Exploration and Production Services for Apache Corporation from 1995 to February 2004. From 1984 to 1995, Ms. Stewart worked in various capacities for Apache Corporation.

Susan B. Ortenstone has been Senior Vice President of El Paso since October 2003. Ms. Ortenstone was Chief Executive Officer for Epic Energy Pty Ltd. from January 2001 to June 2003. She served as Vice President of El Paso Gas Services Company and President of El Paso Energy Communications from December 1997 to December 2000. Prior to that time Ms. Ortenstone worked in various strategy, marketing, business development, engineering, and operations capacities since 1979.

Stephen C. Beasley has been Chairman of the Board and President of ANR Pipeline Company and Tennessee Pipeline Company since May 2005. He has been Director of ANR Pipeline Company since January 2004, Director of Tennessee Gas Pipeline Company since November 2001 and President of Tennessee Pipeline Company since June 2001. Prior to that time, Mr. Beasley worked in various capacities at Tennessee Gas Pipeline since 1987.

James J. Cleary has been Chairman of the Board and President of El Paso Natural Gas Company and Colorado Interstate Gas Company since May 2005. He has been Director and President of El Paso Natural Gas Company and Colorado Interstate Gas Company since January 2004. From January 2001 through December 2003, he served as President of ANR Pipeline Company. Prior to that time, Mr. Cleary served as Executive Vice President of Southern Natural Gas Company from May 1998 to January 2001. He also worked for Southern Natural Gas Company and its affiliates in various capacities since 1979.

James C. Yardley has been Chairman of the Board and President of Southern Natural Gas Company since May 2005, Director of Southern Natural Gas Company since November 2001 and President of Southern Natural Gas Company since May 1998. He served as Vice President, Marketing and Business Development for Southern Natural Gas Company from April 1994 to April 1998. Prior to that time, Mr. Yardley worked in various capacities with Southern Natural Gas and Sonat Inc. since 1978.

Daniel B. Martin has been Director of ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company and Tennessee Gas Pipeline Company since May 2005. He has been Senior Vice President of El Paso Natural Gas Company since February 2000, Senior Vice President of Southern Natural Gas Company and Tennessee Gas Pipeline Company since June 2000 and Senior Vice President of ANR Pipeline Company and Colorado Interstate Gas Company since January 2001. Prior to that time, Mr. Martin worked in various capacities with Tennessee Gas Pipeline Company since 1978.

Available Information

Our website is http://www.elpaso.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the SEC. Information about each of our Board members, as well as each of our Board's standing committee charters, our Corporate Governance Guidelines and our Code of Business Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

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

This report contains 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, adverse weather conditions (such as hurricanes and flooding) 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 and assets face possible risks associated with acts of aggression. 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, this insurance does not cover all risks. Many of our insurance coverages have material deductibles and self-insurance levels, as well as limits on our maximum recovery. As a result, 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 NGL we transport and store are owned by third parties. As a result, the volume of natural gas and NGL involved in these activities depends on the actions of those third parties and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity 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 availability of natural gas supplies;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- decreased natural gas demand due to various factors, including increases in prices and the increased availability or popularity of alternative energy sources such as hydroelectric power;
- increased costs of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands; and
- unfavorable movements in natural gas and NGL prices in certain supply and demand areas.

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 replace contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the change in rates or upstream supply of existing pipeline competitors, as well as 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 LNG contracts depend on volumes and rates, both of which can be affected by the prices of natural gas, LNG and NGL. 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 in industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies' loss of customer base. The success of our transmission, storage and LNG operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional supplies from interconnecting pipelines or LNG facilities to offset the natural decline from existing wells connected to our systems. A decline in energy prices could cause 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. Pricing volatility may, in some cases, impact the value of under or over recoveries of retained gas, imbalances and system encroachments. If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Furthermore, fluctuations in pricing between supply sources and market areas could negatively impact our transportation revenues. 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 NGL;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

The expansion of our pipeline systems by constructing new facilities subjects us to construction and other risks that may adversely affect the financial results of our pipeline businesses.

We may expand the capacity of our existing pipeline, storage or LNG facilities by constructing additional facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- the ability to obtain all necessary approvals and permits by regulatory agencies on a timely basis on terms that are acceptable to us;
- potential changes of federal, state and local statutes and regulations, including environmental requirements that prevent a project from proceeding or increase the anticipated cost of the expansion project;
- impediments on our ability to acquire rights-of-ways or land rights on a timely basis or within our anticipated costs;
- the ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control, that may be material;
- anticipated future growth in natural gas supply does not materialize; and
- the lack of transportation, storage or throughput commitments that result in write-offs of development costs.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve our expected investment return, which could adversely affect our financial position or results of operations.

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 the majority of our proved reserves at December 31, 2005 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 exploration and production business. Changes in natural gas and oil prices can 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 stockholders' equity.

The success of our exploration and production business is dependent, in part, on factors that are beyond our control.

The performance of our exploration and production business is dependent upon a number of factors that we cannot control, including:

- the results of future drilling activity;
- the availability of rigs, equipment and labor to support drilling activity and production operations;
- 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;

- significant increases in future drilling, production and development costs, including drilling rig rates and oil field services costs;
- adverse changes in future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;
- increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- our lack of control over jointly owned properties and properties operated by others;
- the availability of alternative sources of energy;
- 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 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. Additionally, our 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. Each of these risks could result in damage to property, injuries to people or the shut in of existing production as damaged energy infrastructure is repaired or replaced.

We maintain insurance coverage to reduce exposure to potential losses resulting from these operating hazards. 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 which could adversely affect our future results of operations, cash flows or financial condition.

Our drilling operations are also 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 and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. It also requires making estimates based upon economic factors, such as natural gas and oil prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Also, we use a 10 percent discount factor for estimating the value of our reserves, as prescribed by the SEC, which may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our exploration and 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 related to the 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 stockholders' equity.

A portion of our estimated proved reserves are 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.

The success of our exploration and production business depends upon our ability to replace reserves that we produce.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flows from operations. We historically have replaced reserves through both drilling and acquisitions. The business of exploring for, developing or acquiring reserves requires substantial capital expenditures. Our operations require continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics. If we do not continue to make significant capital expenditures, or if our capital resources become limited, we may not be able to replace the reserves that we produce, which would negatively affect our future revenues, cash flows and results of operations.

We face competition from third parties to acquire and develop natural gas and oil reserves.

The natural gas and oil business is highly competitive in the search for and acquisition of reserves. We must identify and precisely locate prospective geologic structures, drill and successfully complete wells in those structures in a timely manner. Our ability to expand our leased land positions in desirable areas is impacted by intensely competitive leasing conditions. Competition for reserves and producing natural gas and oil properties is intense and many of our competitors have financial and other resources that are substantially greater than those available to us. Our competitors include the major and independent natural gas and oil companies, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. If we are unable to compete effectively in the acquisition and development of reserves, our future profitability may be negatively impacted. Ultimately, our future success in the production business is dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

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

Some of our subsidiaries use futures, swaps and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. To the extent we have positions that are not designated or qualify as hedges, changes in commodity prices, interest rates, volatility, correlation factors and the liquidity of the market could cause our revenues, net income and cash requirements to be volatile.

We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments involves estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change favorably. The use of derivatives could require the posting of collateral with our counterparties which can impact our working capital (current assets and liabilities) and liquidity when commodity prices or interest rates change. For additional information concerning our derivative financial instruments, see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Part II, Item 8, Financial Statements and Supplementary Data, Note 10.

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 losses.

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States, including material investment exposure in our power, pipeline and exploration and production projects in Brazil (see Part II, Item 8, Financial Statements and Supplementary Data, Note 16), 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 and we could experience difficulties in managing these liabilities.

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 sold, 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, asset maintenance, 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 prior to closing could result in difficulties in managing the businesses that we are exiting or managing the liabilities retained after closing, including a reduction in historical knowledge of the assets and businesses in managing the liabilities or defending any associated litigation.

Risks Related to Legal and Regulatory Matters

The outcome of pending governmental investigations could be materially adverse to us.

We are subject to numerous governmental investigations including those involving allegations of round trip trades, price reporting of transactional data to the energy trade press, natural gas and oil reserve revisions, accounting treatment of certain hedges of our anticipated natural gas production, sales of crude oil of Iraqi origin under the United Nation's Oil for Food Program and the rupture of one of our pipelines near Carlsbad, New Mexico. These investigations involve, among others, one or more of the following governmental agencies: the SEC, FERC, a grand jury of the U.S. District Court for the Southern District of New York, U.S. Senate Permanent Subcommittee of Investigations, the House of Representatives International Relations Subcommittee, the U.S. Department of Transportation Office of Pipeline Safety and the Department of Justice. We are cooperating with the governmental agency or agencies in each of these investigations. The outcome of each of these investigations is uncertain. Because of the uncertainties associated with the ultimate outcome of each of these investigations and the costs to the Company of responding and participating in these on-going investigations, no assurance can be given that the ultimate costs and sanctions, if any, that may be imposed upon us will not have a material adverse effect on our business, financial condition or results of operation.

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, the U.S. Department of Interior, and various state, local and tribal 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 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 lower risk companies may create downward pressure on tariff rates when subjected to review by the FERC in future rate proceedings. If our pipelines' tariff rates were reduced or re-designed 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.

Environmental compliance and remediation costs and the costs of environmental liabilities could exceed our estimates.

Our operations are subject to various environmental laws and regulations regarding compliance and remediation obligations. Compliance obligations can result in significant costs to install and maintain pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on our operations. Remediation obligations can result in significant costs associated with the investigation and remediation or clean-up of contaminated properties (some of which have been designated as Superfund sites by the Environmental Protection Agency (EPA) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)), as well as damage claims arising out of the contamination of properties or impact on natural resources. It is not possible for us to estimate exactly the amount and timing of all future expenditures related to environmental matters because of:

- The uncertainties in estimating pollution control and clean up costs, including for sites for which only preliminary site investigation or assessments have been completed;
- The discovery of new sites or additional information at existing sites;
- The uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties; and
- The nature of environmental laws and regulations, including the interpretation and enforcement thereof.

Currently, various legislative and regulatory measures to address greenhouse gas (GHG) emissions (including carbon dioxide and methane) are in various phases of discussion or implementation. These include the Kyoto Protocol, proposed federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in GHG emissions. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. These actions could also impact the consumption of natural gas and oil, thereby affecting our pipeline and exploration and production operations.

Although we believe we have established appropriate reserves for our environmental liabilities, we could be required to set aside additional amounts due to these uncertainties which could significantly impact our future consolidated results of operations, cash flows or financial position. For additional information concerning our environmental matters, see Part I, Item 3, Legal Proceedings and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Costs of litigation matters 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 could be material. For additional information concerning our litigation matters and other contingent liabilities, see Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Our system of internal controls is designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes. A loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.

Our system of internal controls is designed to provide reasonable assurance that the objectives of the control system are met. However, any system of internal controls is subject to inherent limitations and the design of our controls may not provide absolute assurances that all of our objectives will be entirely met. This includes the possibility that controls may be inappropriately circumvented or overridden, that judgments in decision-making can be faulty and that misstatements due to errors or fraud may not be prevented or detected.

Risks Related to Our Liquidity

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

We have significant debt, debt service and debt maturity obligations. The ratings assigned to our senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody's Investor Service (Moody's) and B- by Standard & Poor's. These ratings have increased our cost of capital and our operating costs, particularly in our trading operations, and could impede our access to capital markets. Moreover, we must retain greater liquidity levels to operate our business than if we had investment grade credit ratings. If our ability to generate or access capital becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 14, for a further discussion of our debt.

We may not achieve our targeted level of debt reduction or complete our asset sales in a timely manner or at all.

Our ability to achieve our announced targets to reduce our debt obligations and complete asset sales, as well as the timing of their achievement, is subject, in part, to factors beyond our control. These factors include our ability to locate potential buyers in a timely fashion and obtain a reasonable price, and our ability to preserve sufficient cash flow to service our debt and other obligations. If we fail to achieve these targets in a timely manner, our liquidity or financial position could be materially adversely affected. In addition, it is possible that our asset sales could be at prices that are below the current book value for the assets, which could result in losses that could be substantial.

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, which become more restrictive over time, and cross-acceleration provisions. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit and from borrowing under our credit agreements, and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we might not be able to repay such debt and other financing obligations.

Some of our credit agreements are collateralized by our equity interests in ANR, CIG, EPNG, Southern Gas Storage Company (which owns an interest in Bear Creek Storage Company), ANR Storage Company, TGP and certain natural gas and oil reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to the collateral, and we could be required to sell these collateral interests.

We are subject to financing and interest rate exposure risks.

Our future success depends on our ability to access capital markets and obtain financing at cost effective rates. This is dependent on a number of factors, many of which we cannot control, including changes in:

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

In addition, although we hedge a portion of our exposure to interest rate movements, our financial condition and liquidity could be adversely affected if there is a negative movement in interest rates.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

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

ITEM 3. LEGAL PROCEEDINGS

Details of the cases listed below, as well as a description of our other legal proceedings are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, and are incorporated herein by reference.

The shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,*filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and *Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,*filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation,* *William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002.

The shareholder class actions relating to our reserve restatement filed in the U.S. District Court for the Southern District of Texas, Houston Division, which have now been consolidated with the above referenced purported shareholder class actions, are: *James Felton v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Sinclair Haberman v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Patrick Hinner v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Stanley Peltz v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Yolanda Cifarelli v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Andrew W. Albstein v. El Paso Corporation, William Wise; George S. Johnson v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, and D. Dwight Scott; Robert Corwin v. El Paso Corporation, Mark Leland, Brent Austin, Ronald Kuehn, Jr., D. Dwight Scott and William Wise; Michael Copland v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Leslie Turbowitz v. El Paso Corporation, Mark Leland, Brent Austin, Ronald Kuehn, Jr., D. Dwight Scott and William Wise; David Sadek v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott; Stanley Sved v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Nancy Gougler v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; William Sinnreich v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Joseph Fisher v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Glickenhaus & Co. v. El Paso Corporation, Rod Erskine, Ronald Kuehn, Jr., Brent Austin, William Wise, Douglas Foshee and D. Dwight Scott; and Thompson v. El Paso Corporation, Ronald Kuehn, Douglas Foshee and D. Dwight Scott.*

The stayed shareholder derivative actions filed in the United States District Court for the Southern District of Texas, Houston Division are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002, and *Russo v. William Wise, Brent Austin, Dwight Scott, Ralph Eads, Ronald Kuehn, Jr., Douglas Foshee, Rodney Erskine, PricewaterhouseCoopers and El Paso Corporation* filed in September 2004. The consolidated shareholder derivative action filed in Houston is *John Gebhart and Marilyn Clark v. El Paso Corporation, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, William Wise, Joe Wyatt, Ralph Eads, Brent Austin and John Somerhalder* filed in November 2002. Gebhardt Plaintiffs filed a Third Amended Petition in October 2005 adding additional defendants, James Dunlap, Douglas Foshee, Robert Goldman, Thomas Hix, William Joyce, Michael Talbert and John Whitmire. The two derivative actions filed in Delaware Chancery Court are *Stephen Brudno, et al. v. William A. Wise, et al.* filed in October 2002 (which was voluntarily dismissed in July 2005) and *Alan Laties v. William Wise, John L. Bissell, Juan Carlos Braniff, James L. Dunlap, Douglas L. Foshee, Robert W. Goldman, Anthony Hall, Thomas R. Hix, William H. Joyce, Ronald L. Kuehn, Jr., J. Carlton MacNeil, Jr., J. Michael Talbert, John L. Whitmire, Joe B. Wyatt and El Paso Corporation*. The Laties case was filed in April 2005 in Delaware Chancery Court nominally on behalf of El Paso against William Wise and the board of directors. An identical suit was filed by Laties in Harris County District Court on August 25, 2005, but has never been served on El Paso. The Laties case filed in Delaware was dismissed by the court in December 2005.

Environmental Proceedings

Air Permit Violation. In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and natural gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. Pursuant to discussions with LDEQ, we have reached an agreement to resolve the allegations for $77,287. We signed the settlement agreement on November 28, 2005, and will pay the penalty once LDEQ has completed its approval process for this settlement.

Coastal Eagle Point Air Issues. On April 1, 2004, the New Jersey Department of Environmental Protection issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking $183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003 at our former

Eagle Point refinery. We filed an administrative appeal contesting the allegations and penalty. We reached an agreement to resolve the allegations and appeal for a penalty for $119,400, have executed the settlement agreement, and paid the agreed penalty in the fourth quarter of 2005, fully resolving this matter.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality (TCEQ) issued an "Executive Director's Preliminary Report and Petition" seeking $645,477 in penalties relating to air violations alleged to have occurred at El Paso's former Corpus Christi, Texas refinery from 1996 to 2000. We subsequently filed a hearing request to protect our procedural rights. In March 2005, the parties reached an agreement in principle to resolve the allegations for $272,097. In September 2005, the parties finalized the written terms of the settlement agreement. The final terms allow for $136,049 to be paid as a penalty and $136,049 to be spent on a supplemental environmental project. El Paso and TCEQ have executed the final agreement and all payments required to resolve this matter have been made.

EPNG State of Arizona Pipe-Coating. In September 2005, the Arizona Department of Environmental Quality (ADEQ) issued a Notice of Violation (NOV) for alleged regulatory violations related to our handling of asbestos-containing asphaltic pipe coating. We have been informed by the Attorney General for the State of Arizona, on behalf of the ADEQ, of its intent to assess a civil penalty and require preventive actions by us to resolve the NOV. Although the likely penalty and costs associated with any preventive actions are unknown at this time, the ADEQ proposed a fine of less than $1 million. We are in discussions with the state in an effort to resolve this matter.

Kentucky Polychlorinated Biphenyls (PCB) Project. In November 1988, the Kentucky Natural Resources and Environmental Protection Cabinet filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into interim agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the EPA. Despite remediation efforts, the agency may raise additional technical issues or seek additional remediation work and/or penalties in the future.

Natural Buttes. In May 2003, we met with the EPA to discuss potential prevention of significant deterioration violations due to a de-bottlenecking modification at CIG's facility. The EPA issued an Administrative Compliance Order and we were in negotiations with the EPA as to the appropriate penalty. In September 2005, we were informed that the EPA referred this matter to the U.S. Department of Justice (DOJ). We have since entered into a tolling agreement with the DOJ in order to facilitate continuing settlement discussions.

Shoup Natural Gas Processing Plant. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the TCEQ concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to emission limit, testing, reporting and recordkeeping issues in 2001. On December 29, 2004, TCEQ issued an Executive Director's Preliminary Report and Petition revising the allegations from the NOE and seeking a penalty of $419,650. We answered the Petition disputing the allegations and the penalty. We have reached an agreement to resolve the matter by agreeing to pay a penalty of $106,439 and conduct a supplemental environmental project costing $95,961. We paid the penalty to TCEQ and will perform the supplemental environmental project upon final execution of the settlement by TCEQ.

Tucson Waste Management. In September 2004, we received a NOV from the ADEQ for alleged failure to comply with waste management regulations at EPNG's Tucson compressor station. EPNG fulfilled their request for information and documentation related to the alleged noncompliance. This matter has been referred to the Office of the Attorney General for the State of Arizona, has informed us of its intent to require a civil penalty to resolve the NOV. The amount of the penalty is unknown at this time, but we are in discussions with the State in an effort to resolve this matter.

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

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of February 24, 2006, we had 44,220 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

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

	High	Low	Dividends
2005			
Fourth Quarter	$14.07	$10.78	$ 0.04
Third Quarter	14.16	11.13	0.04
Second Quarter	11.87	9.30	0.04
First Quarter	13.15	10.01	0.04
2004			
Fourth Quarter	$11.85	$ 8.42	$ 0.04
Third Quarter	9.20	7.37	0.04
Second Quarter	7.95	6.58	0.04
First Quarter	9.88	6.57	0.04

On February 14, 2006, we declared a quarterly dividend of $0.04 per share of our common stock, payable on April 3, 2006, to shareholders of record as of March 3, 2006. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set apart for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restriction on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If our fixed charge ratio were to exceed the permitted maximum level, our ability to pay additional dividends would be restricted.

Odd-lot Sales Program

We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. This voluntary program offers these stockholders a convenient method to sell all of their odd-lot shares at one time without incurring any brokerage costs. We also have a dividend reinvestment and common stock purchase plan available to all of our common stockholders of record. This voluntary plan provides our stockholders a convenient and economical means of increasing their holdings in our common stock. Neither the odd-lot program nor the dividend reinvestment and common stock purchase plan have a termination date; however, we may suspend either at any time. You should direct your inquiries to Computershare Trust Company, N.A., our stock transfer agent at 1-877-453-1503.

ITEM 6. SELECTED FINANCIAL DATA

The following historical selected financial data excludes our south Louisiana gathering and processing operations, certain international power operations, certain of our international natural gas and oil production operations and our petroleum markets and coal mining businesses, all of which are presented as discontinued operations in our financial statements for all periods. The selected financial data below should be read together with Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data included in this Report on Form 10-K. These selected historical results are not necessarily indicative of results to be expected in the future.

	As of or for the Year Ended December 31,				
	2005	2004	2003	2002	2001
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues[(1)]	$ 4,017	$ 5,539	$ 6,339	$ 6,455	$ 9,871
Loss from continuing operations[(2)]	$ (702)	$ (829)	$ (605)	$(1,336)	$ (267)
Net loss available to common stockholders	$ (633)	$ (947)	$(1,883)	$(1,875)	$ (447)
Basic and diluted loss per common share from continuing operations	$ (1.13)	$ (1.30)	$ (1.01)	$ (2.39)	$ (0.53)
Cash dividends declared per common share	$ 0.16	$ 0.16	$ 0.16	$ 0.87	$ 0.85
Basic and diluted average common shares outstanding	646	639	597	560	505
Financial Position Data:					
Total assets[(1)]	$31,838	$31,383	$36,968	$41,947	$44,273
Long-term financing obligations[(3)]	17,023	18,241	20,275	16,105	12,690
Securities of subsidiaries[(3)]	31	367	447	3,421	4,013
Stockholders' equity	3,389	3,438	4,346	5,749	6,666

(1) Decreases were a result of asset sales activities during these periods. See Part II, Item 8, Financial Statements and Supplementary Data, Note 3.

(2) We incurred net losses of $0.4 billion in 2005, $1.1 billion in 2004, $1.2 billion in 2003 and $0.9 billion in 2002 related to gains, losses and impairments of assets and equity investments as well as restructuring charges related to industry changes and the realignment of our businesses under our strategic plan. In 2003, we also entered into an agreement in principle to settle claims associated with the western energy crisis of 2000 and 2001. This settlement resulted in charges of $59 million in 2005, $104 million in 2003 and $899 million in 2002, before income taxes. In addition, we incurred ceiling test charges of $5 million, $5 million and $1.9 billion in 2003, 2002 and 2001 on our full cost natural gas and oil properties. During 2001, we merged with The Coastal Corporation and incurred costs and asset impairments related to this merger that totaled approximately $1.5 billion. For further discussions of events affecting comparability of our results in 2005, 2004 and 2003, see Part II, Item 8, Financial Statements and Supplementary Data, Notes 2 through 5.

(3) The increases in total long-term financing obligations in 2002 and 2003 was a result of the consolidations of our Chaparral and Gemstone power investments, the restructuring of other financing transactions, and in 2003, the reclassification of securities of subsidiaries as a result of our adoption of SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*.

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

Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed beginning on page 24.

During 2005, we discontinued our south Louisiana gathering and processing operations (previously part of our Field Services segment) and our international power operations at our Nejapa, CEBU and East Asia Utilities power plants. Our operating results for all periods presented reflect these operations as discontinued.

Overview

Business Purpose and Description. Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own North America's largest natural gas pipeline system and are a large independent natural gas and oil producer. We also maintain an energy marketing and trading business that supports the marketing of our natural gas and oil production and the management of the risk associated with commodity prices.

During the past several years we have sold nearly $12 billion of assets to reduce debt and improve liquidity. These businesses were either not core to our long-term objectives or were performing below the expectations we had for them at the time we made the investment. These divestitures have resulted in significant financial losses through asset impairments, realized losses on asset sales and reduction of income from the businesses sold. We have sold substantially all of our power and midstream assets and in 2006 we expect to be substantially complete with the divestiture of our non-core activities.

Drivers of our Profitability. Our future profitability will be driven by a number of factors including our ability to:

Pipelines

— Expand our existing pipeline systems and gain access to new supply areas and sources
— Contract and recontract pipeline capacity with our customers
— Successfully resolve our pending rate cases
— Improve operational efficiency

Exploration and Production / Marketing and Trading

— Increase our natural gas and oil proved reserve base and production volumes through successful drilling programs or acquisitions and efficient operations
— Manage commodity price risk to optimize the amounts we receive for the commodities we sell

Other

— Successfully manage and complete the orderly exit of our legacy assets and trading positions
— Successfully resolve legacy contingencies
— Reduce debt levels and interest costs

Summary of Operational/Financial Performance in 2005. During 2005, we continued to develop our core pipeline and exploration and production operations. Our pipelines delivered strong financial performance and our exploration and production business stabilized. However, our earnings were negatively impacted by substantial mark-to-market losses on our natural gas and power derivative contracts due to commodity price increases, impairment charges taken in conjunction with the divestiture of non-core assets and accruals for potential obligations related to various legacy matters. Additionally, the impact of Hurricanes Katrina and Rita affected our pipeline and production operations in the second half of 2005. Listed below and in the individual segment results that follow is a further discussion of the events affecting 2005 as well as progress in our key areas of focus:

Area of Operations	Events Affecting Operations
Pipelines	Finalized new rates at Southern Natural Gas Company.
	Re-contracted or contracted available or expiring capacity.
	Proceeded with several pipeline expansion projects in our pipeline systems and at our Elba Island LNG facility.
	Incurred significant damage to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Katrina and Rita. These hurricanes also resulted in the shut-in of a significant portion of gas supply on our systems.
E & P and Marketing and Trading	Completed the turnaround of our exploration and production business by (i) stabilizing production rates, in spite of incurring a reduction of our annual production of approximately 12 Bcfe as a result of Hurricanes Katrina and Rita and (ii) growing our reserve base through our capital drilling program and through four acquisitions of natural gas and oil properties, including our acquisition of Medicine Bow.
	Sold our natural gas and oil production at higher commodity prices. However, we incurred substantial losses associated with derivative contracts used to provide price protection on our production and in settling hedges that had been put in place during a lower price environment.
	Assigned or terminated the majority of our power contracts, our Cordova tolling agreement and the remaining derivative contracts associated with our power contract restructuring operations.
Other	Completed or announced the divestiture of substantially all of our remaining operations in our midstream, power and other businesses, for total proceeds of approximately $2.4 billion ($2.0 billion through December 31, 2005). The net effect of these sales activities resulted in substantial losses in 2005.
	Furthered legal and contractual disputes, including those related to our Brazilian power plants and domestic legal matters.

What to Expect Going Forward. For 2006, our pipeline operations are positioned to provide steady operating results based on the current levels of contracted capacity, expansion plans and the status of rate and regulatory actions. Our exploration and production operating results will be driven by continued success of our drilling programs, our ability to restore the remaining production that has been shut-in since late September 2005 due to Hurricane Rita, our ability to manage increases in the cost of production services and continued high commodity prices. Additionally, a substantial portion of our below-market derivative contracts are scheduled to expire in 2006, which will give us a greater opportunity to participate in the higher commodity pricing environment.

In 2006, we will also strive to achieve our net debt (debt, less cash) target of $14 billion by year-end, complete the sale of our Asian and Central American power assets (substantially all of which are under contract), pursue the divestiture of our remaining domestic power assets and complete the resolution of the issues related to our Brazilian power investments as well as other remaining legacy issues.

Liquidity

Overview. The year 2005 was a turning point for us in terms of our liquidity and capital resources. We began the year focused on reducing liquidity concerns, strengthening our credit metrics, selling a number of non-core assets and businesses and reducing cash flow risks associated with a number of derivative transactions put in place in prior years. During 2005, we (i) completed asset sales for proceeds of $2.0 billion, (ii) replaced some of our cash margining requirements with letters of credit and (iii) entered into or completed transactions to divest or reduce the risk of a substantial portion of our power portfolio, including our Cordova tolling agreement. While we continue to closely monitor our liquidity, we believe the events of 2005 and those over the past several years have allowed us to turn our attention in 2006 to expanding our core businesses of natural gas pipelines and exploration and production.

Available Liquidity. We rely on cash generated from our operations as a significant source of liquidity. We supplement this, as needed, through the use of available credit facilities, project and bank financings, proceeds from asset sales and the issuance of debt, preferred securities and equity securities. Our subsidiaries are a significant source of liquidity to us and they participate in our cash management program to the extent they are permitted under their financing agreements and indentures. Under this program, depending on whether a participating subsidiary has short-term cash surpluses or requirements, we either provide cash to them or they provide cash to us. We expect that our future funding for working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources. As of December 31, 2005, we had available liquidity as follows:

	(in billions)
Available cash	$2.0
Available capacity under our credit agreements[1]	0.3
Net available liquidity at December 31, 2005	$2.3

(1) See discussion of Capital Resources on page 42.

Expected 2006 Cash Flows. In addition to our available liquidity, we expect to generate significant operating cash flow in 2006, which we will supplement with $1.2 billion of expected proceeds from asset sales, including $0.4 billion of cash upon completing the assignment of a majority of our power derivative portfolio. We expect to also generate cash from financing activities as needed, including the anticipated issuance of common stock during the year.

In 2006, we expect to spend approximately $2.0 billion on capital investments in our core pipeline and exploration and production businesses, intended to both maintain and grow these businesses. Our capital program for 2006 is forecasted as follows (in billions):

	Pipelines	Exploration and Production	Total
Maintenance	$0.5	$0.7	$1.2
Growth	0.5	0.3	0.8
Total	$1.0	$1.0	$2.0

As of December 31, 2005, we had debt maturities for 2006 and 2007 of approximately $0.6 billion and $0.9 billion. We also had approximately $0.6 billion of zero-coupon debentures with a stated maturity of 2021 that the holders required us to redeem for cash in February 2006. In 2007, we have approximately $0.6 billion of debt that the holders can require us to redeem which, when combined with our maturities, could require us to retire up to $1.4 billion of debt in 2007.

Factors Impacting our Liquidity. Each of our existing and future sources of cash is impacted by operational and financial risks that influence the overall amount of cash generated and the capital available to us. For example, cash generated by our business operations may be impacted by, among other things, changes in commodity prices and the extent to which we hedge our natural gas and oil production, demands for our commodities or services, success in recontracting existing pipeline capacity contracts, drilling success and competition from other providers or alternative energy sources. Collateral demands or recovery of cash posted as collateral are impacted by commodity prices, hedging levels and the credit quality of us and our counterparties. Cash generated by future asset sales may depend on the condition and location of the assets, the number of interested buyers and our ability to successfully complete the transaction. In addition, our future liquidity will be impacted by our ability to access capital markets which may be restricted due to our credit ratings and general market conditions. The following is a further discussion of some of these factors and their impact on us in 2005 or potential impact in future periods.

- *Price Risk Management Activities.* We enter into derivative contracts to provide price protection on a portion of our anticipated natural gas and oil production. Specifically, our Exploration and Production and Marketing and Trading segments use swap and option contracts to fix the amount of cash we will receive on contracted volumes sold or to provide floor or ceiling prices on these volumes. Floor prices are the minimum cash prices to be received and ceiling prices are the maximum cash prices to be received under the option contracts.

  As of December 31, 2005, a number of our swap contracts have been designated as and are accounted for as accounting hedges. However, our option contracts and certain other swap contracts have not been designated as hedges and are therefore marked-to-market through earnings each period. The accounting method used for these contracts affects the timing of the income or loss recognized on any individual contract in periods prior to its settlement. However, through the settlement date, the cumulative income or loss and cash flow impacts of a contract are identical whether or not it is accounted for as a hedge or is marked-to-market through earnings each period. For a further discussion of the income impacts of these contracts, see our Exploration and Production and Marketing and Trading segments' discussions of operating results. The following table shows the contracted volumes and the minimum, maximum and average cash prices that we will ultimately receive under these contracts upon settlement or when the underlying production is sold:

	Swaps[1]		Floors[1]		Ceilings[1]	
Natural Gas	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
2006	110	$ 4.89	120	$ 7.00	60	$ 9.50
2007	5	$ 3.56	51	$ 6.41	21	$ 9.00
2008	5	$ 3.42	18	$ 6.00	18	$10.00
2009-2012	16	$ 3.74	17	$ 6.00	17	$ 8.75
Oil						
2006	1,428	$52.45	—	—	—	—
2007	192	$35.15	1,009	$55.00	1,009	$60.38
2008	—	—	930	$55.00	930	$57.03

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

- *Cash Margining Requirements on Derivative Contracts.* A substantial portion of our natural gas and oil derivative contracts are at prices significantly below current market prices, which has resulted in us posting substantial cash margin deposits with the counterparties for the value of these instruments. During 2005, we experienced volatility in the level of margins posted, primarily resulting from the increase in commodity prices as a result of Hurricanes Katrina and Rita. The resulting increased commodity prices required us to post $0.7 billion of additional cash margin deposits with counterparties to our derivative contracts. In the fourth quarter of 2005, $0.5 billion of margin deposits had been returned to us due to a decrease in prices and settlements, but these cash recoveries were largely offset by cash collateral requirements relating to an agreement we entered into to assign a majority of the contracts in our power portfolio to a third party. In 2006, we expect approximately $1.2 billion of collateral supported by both cash margin deposits and letters of credit, to be returned to us, which includes the collateral that we anticipate to receive upon completion of the assignment of the positions related to our power portfolio in December 2005. If commodity prices decrease, we could recover some of this amount earlier than anticipated.

Any future increases in prices could have a significant impact on our operating cash flows as additional margin deposits would be required. Based on our derivative positions at December 31, 2005, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements by $19 million for transactions that settle in 2006, $6 million for transactions that settle in 2007, $5 million for transactions that settle in 2008 and $13 million for transactions that settle in 2009 and thereafter.

- *Hurricanes.* Hurricanes Katrina and Rita impacted virtually all producers and transporters doing business in the Gulf of Mexico region. We incurred significant damage to our property, including our transmission facilities. To date, we estimate total repair costs related to these storms to be approximately $457 million, of which $380 million is claimed through our property damage insurer, which is a mutual insurance company that is subject to individual and aggregate loss limits by event. Based on the level of our claims and the claims of all insured parties, we will not receive a portion of the costs we will incur to repair our systems. Based on current estimates, we anticipate that up to $164 million of capital and maintenance expenditures claimed through our property damage insurer will not be recovered due to these limits. Also, the timing of reimbursements we will receive may occur later than the capital expenditures on the damaged facilities, which may increase our net capital expenditures for 2006 and could negatively impact our estimates of cash flow.

Despite the impact of the factors above, we were able to largely mitigate the effects of these items in 2005 through the successful completion of a number of asset sales, the issuance of $400 million of notes by CIG and by entering into a six month, $400 million revolving borrowing base credit agreement (with an initial borrowing capacity of $300 million). We believe we will have sufficient liquidity to meet our ongoing liquidity and cash needs through the combination of available cash and borrowings under our credit agreements. For a further discussion of risks that may impact our cash flows, see discussion on page 32.

Capital Resources

Existing Financing Facilities. During 2005, we continued to reduce our overall debt as part of our strategic plan. We also issued $750 million of convertible preferred stock primarily to satisfy our remaining obligations under the Western Energy Settlement and to redeem the preferred stock of a consolidated subsidiary. Our debt activity during 2005 was as follows (in millions):

Debt obligations as of December 31, 2004	$19,196
Principal amounts borrowed	1,638
Repayment/retirement of principal	(1,912)
Sale of entities[1]	(575)
Other	(113)
Total debt as of December 31, 2005	$18,234

[1] Related to the sale of Cedar Brakes I and II and Mohawk River Funding II.

As of December 31, 2005, we have approximately $0.3 billion of available capacity under several credit facilities as described below:

- *$3 billion credit agreement.* As of December 31, 2005, we had borrowed $1.23 billion as a term loan and issued approximately $1.7 billion of letters of credit under this credit agreement. The agreement is collateralized by our equity interests in TGP, EPNG, ANR, CIG, Southern Gas Storage Company (which owns an interest in Bear Creek Storage Company) and ANR Storage Company.

- *$500 million revolving credit facility.* In August 2005, our subsidiary, EEPC, entered into and borrowed $500 million under a five-year revolving credit facility bearing interest at LIBOR plus

1.875%. Amounts borrowed were used to partially fund the acquisition of Medicine Bow. The facility can be utilized for funded borrowings or for the issuance of letters of credit and is collateralized by certain EEPC natural gas and oil production properties. Our current intent is to issue $500 million to $800 million of our common stock to repay amounts borrowed under this facility and for other purposes, the timing of which is dependent on market conditions.

- *$400 million revolving credit agreement.* In November 2005, we entered into a $400 million revolving borrowing base credit agreement collateralized by certain natural gas and oil production properties owned by one of our subsidiaries, which is also a co-borrower. Under the agreement we have initial borrowing availability of $300 million. The credit agreement can be used for revolving credit loans or for the issuance of letters of credit and will mature in May 2006. As of December 31, 2005, there were no outstanding borrowings or letters of credit issued under this agreement.

The availability of borrowings under these credit agreements and our ability to incur additional debt is subject to various conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements and continued accuracy of the representations and warranties contained in the agreements. The financial coverage ratios under our $3 billion credit agreement change over time. However, these covenants currently require our Debt to Consolidated EBITDA (as defined in the credit agreement) not to exceed 6.25 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in the credit agreement. As of December 31, 2005, our ratio of Debt to Consolidated EBITDA was 4.79 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 2.15 to 1.

Overview of Cash Flow Activities for 2005 Compared to 2004

For the years ended December 31, 2005 and 2004, our cash flows are summarized as follows:

	2005	2004
	(In billions)	
Cash flow from operations		
Continuing operating activities		
Net loss before discontinued operations	$(0.7)	$(0.8)
Non-cash income items	1.6	2.3
Changes in assets and liabilities		
Change in broker margin deposits	(0.7)	0.1
Settlements of derivatives designated as hedges	(0.4)	—
Assignment of power derivative liabilities	(0.4)	—
Proceeds from entering into derivative contracts	0.4	—
Changes in other assets and liabilities	0.5	(0.5)
Total cash flow from operations	$ 0.3	$ 1.1
Other cash inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 1.4	$ 1.9
Net proceeds from restricted cash	0.1	0.6
Other	0.2	0.1
	1.7	2.6
Continuing financing activities		
Net proceeds from the issuance of long-term debt	1.6	1.3
Proceeds from the issuance of preferred and common stock	0.7	0.1
Net discontinued operations activity	0.6	1.0
	2.9	2.4
Total other cash inflows	$ 4.6	$ 5.0

	2005	2004
	(In billions)	
Other cash outflows		
Continuing investing activities		
Additions to property, plant, and equipment	$ 1.7	$ 1.8
Net cash paid for acquisitions	1.0	—
Other	0.1	—
	2.8	1.8
Continuing financing activities		
Payments to retire long-term debt and redeem preferred interests	1.7	2.5
Payments of revolving credit facilities	—	0.9
Redemption of preferred stock of a subsidiary	0.3	—
Dividends paid to common stockholders	0.1	0.1
Other	—	0.1
	2.1	3.6
Total other cash outflows	4.9	5.4
Net change in cash	$ —	$ 0.7

Cash from Continuing Operating Activities

During the year ended December 31, 2005, our net operating cash flow decreased by $0.8 billion compared to 2004, primarily due to activities associated with our derivative contracts. During 2005, we paid approximately $0.4 billion of settlements on our hedging derivatives and paid approximately $0.4 billion to assign or terminate our Cordova power contract and our contracts to supply power to Cedar Brakes I and II. In addition, we received approximately $0.4 billion to assign a portion of our power derivative portfolio to Morgan Stanley, but were required to deposit $0.4 billion of cash margin with them related to offsetting contracts we entered into until we complete the assignment. We expect to receive this cash margin back in the first half of 2006 when the original contracts are assigned and the offsetting contracts are terminated. Our cash margining requirements also increased on our other derivative contracts by an additional $0.3 billion in 2005 due to the impact of commodity price increases in 2005.

The net cash outflows of $1.1 billion associated with these derivatives and their related cash margin deposits were partially offset by a $0.3 billion increase in cash flows from our other operating activities, including a $0.2 billion decrease in the amount of our payments associated with the Western Energy Settlement in 2005 as compared to 2004.

Cash From Continuing Investing Activities

For the year ended December 31, 2005, net cash used in our continuing investing activities was $1.1 billion. Among other items, during the year we received net proceeds of approximately $0.6 billion from sales of our power assets as well as $0.7 billion from the sales of our general partnership interests in Enterprise and various other assets in our Field Services segment.

Our 2005 capital expenditures, including acquisitions, were as follows (in billions):

Production exploration, development and acquisition expenditures	$1.8
Pipeline expansion, maintenance and integrity projects	0.8
Other	0.1
Total capital expenditures and acquisitions	$2.7

Cash From Continuing Financing Activities

Net cash provided by our continuing financing activities was $0.8 billion for the year ended December 31, 2005. We generated cash of $2.3 billion primarily from the issuance of $0.7 billion of convertible preferred stock and $1.6 billion of long-term debt. We also had $0.6 billion of cash contributed by our discontinued operations primarily as a result of proceeds from sales of these assets. Offsetting our cash inflows were payments of $1.7 billion to retire long-term third party debt and $0.3 billion to redeem the cumulative preferred stock of a subsidiary, El Paso Tennessee Pipeline Co. (EPTP). Additionally, we paid dividends of $0.1 billion during 2005.

Off-Balance Sheet Arrangements

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. Certain of these arrangements are often referred to as off-balance sheet arrangements and include guarantees, letters of credit and other interests in variable interest entities.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to purchase services from a third party and then fails to do so, we would be required to either purchase these services or make payments to the third party to compensate them for any losses they incurred because of this non-performance. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental matters and necessary expenditures to ensure the safety and integrity of the assets sold.

We record accruals for our guaranty and indemnification arrangements at their fair value when they are issued and subsequently adjust those accruals when we believe it is both probable that we will have to pay amounts under the arrangements and those amounts can be estimated. As of December 31, 2005, we had a liability of $91 million related to our guarantees and indemnification arrangements. These arrangements had a total stated exposure of $233 million, for which we are indemnified by third parties for $29 million. These amounts exclude guarantees for which we have issued related letters of credit discussed below.

In addition to the exposures described above, we received a ruling from a trial court, which was upheld on appeal, that we are required to indemnify a third party for benefits paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $380 million associated with our estimated exposure under this matter as of December 31, 2005. For a further discussion of this matter, see Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Letters of Credit

We enter into letters of credit in the ordinary course of our operations as well as periodically in conjunction with sales of assets or businesses. As of December 31, 2005, we had outstanding letters of credit of approximately $2.0 billion, including $1.2 billion of letters of credit securing our recorded obligations related to price risk management activities.

Interests in Variable Interest Entities

We have significant interests in a number of variable interest entities, primarily investments held in our Power segment. A variable interest entity is a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. We are required to consolidate such entities if we are allocated the majority of the variable interest entity's losses or return, including fees paid by the entity. If we are not the primary beneficiary of the variable interest entity's operations, consolidation is not required; as of December 31, 2005, we do not consolidate approximately 17 variable interest entities for this reason. For additional information on these entities, including our related interests in those entities, see Part II, Item 8, Financial Statements and Supplementary Data, Note 21, Investments in, Earnings from and Transactions with Unconsolidated Affiliates.

Contractual Obligations

We are party to various contractual obligations, which include the off-balance sheet arrangements described above. A portion of these obligations are reflected in our financial statements, such as short-term and long-term debt and other accrued liabilities, while other obligations, such as demand charges under transportation and storage commitments and operating leases and capital commitments, are not reflected on our balance sheet. The following table summarizes our contractual cash obligations as of December 31, 2005, for each of the years presented (all amounts are undiscounted):

	2006	2007	2008	2009	2010	Thereafter	Total
				(In millions)			
Long-term financing obligations:[1]							
Principal	$1,211	$ 781	$ 676	$2,479	$2,058	$11,085	$18,290
Interest	1,316	1,281	1,212	1,145	945	10,939	16,838
Other contractual liabilities[2]	101	47	32	15	12	50	257
Operating leases[3]	81	71	14	11	7	33	217
Other contractual commitments and purchase obligations:[4]							
Transportation and storage[5]	112	100	94	91	89	368	854
Commodity purchases[6]	33	32	21	14	14	28	142
Other[7]	377	48	52	22	22	41	562
Total contractual obligations	$3,231	$2,360	$2,101	$3,777	$3,147	$22,544	$37,160

(1) See Part II, Item 8, Financial Statements and Supplementary Data, Note 14.

(2) Includes contractual, environmental and other obligations included in other current and noncurrent liabilities in our balance sheet. Excludes expected contributions to our pension and other postretirement benefit plans of $61 million in 2006 and $176 million for the four year period ended December 31, 2010, because these expected contributions are not contractually required. Also excludes potential amounts due under an indemnification of a former subsidiary for benefits being paid to a closed group of retirees. We have a liability of approximately $380 million related to the litigation associated with this matter as of December 31, 2005.

(3) See Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

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

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

(6) Includes purchase commitments for natural gas and power.

(7) Includes commitments for drilling and seismic activities in our exploration and production operations and various other maintenance, engineering, procurement and construction contracts, as well as service and license agreements used by our other operations.

Commodity-based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing and Trading segments to manage the price risk of commodities. In the tables below, derivatives designated as hedges primarily consist of swaps used to hedge natural gas production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps, tolling agreements and other natural gas and power purchase and supply contracts, our historical energy trading activities and our power contract restructuring activities (which were fully disposed of in 2004 and 2005).

The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2005:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges[1]						
Assets	$ 31	$ —	$ —	$ —	$ —	$ 31
Liabilities	(570)	(62)	(34)	(18)	—	(684)
Total derivatives designated as hedges	(539)	(62)	(34)	(18)	—	(653)
Other commodity-based derivatives						
Exchange-traded positions[1]						
Assets	191	360	158	—	—	709
Liabilities	(155)	(1)	—	—	—	(156)
Non-exchange traded positions[2]						
Assets	414	467	229	135	16	1,261
Liabilities	(693)	(979)	(501)	(377)	(27)	(2,577)
Total other commodity-based derivatives	(243)	(153)	(114)	(242)	(11)	(763)
Total commodity-based derivatives	$(782)	$(215)	$(148)	$(260)	$(11)	$(1,416)

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

(2) During the first quarter of 2006, we assigned our contracts to supply natural gas to the Jacksonville Electric Authority and The City of Lakeland for no cash consideration. We will record a gain of approximately $50 million related to this assignment in 2006.

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2005 and 2004:

	Derivatives Designated as Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at December 31, 2003	$ (31)	$ 1,437	$ 1,406
Fair value of contract settlements during the period	49	(848)	(799)
Change in fair value of contracts	38	(641)	(603)
Designation of other commodity based derivatives as hedges[(1)]	(592)	592	—
Option premiums paid[(2)]	—	64	64
Net change in contracts outstanding during the period	(505)	(833)	(1,338)
Fair value of contracts outstanding at December 31, 2004	(536)	604	68
Fair value of contract settlements during the period[(3)]	665	(174)	491
Change in fair value of contracts	(793)	(767)	(1,560)
Assignment of power contracts	—	(442)	(442)
Reclassification of derivatives that no longer qualify as hedges[(4)]	11	(11)	—
Option premiums paid[(2)]	—	27	27
Net change in contracts outstanding during the period	(117)	(1,367)	(1,484)
Fair value of contracts outstanding at December 31, 2005	$(653)	$ (763)	$(1,416)

(1) Represents the fair value of the contracts on the day they were designated as hedges.

(2) Amounts are net of premiums received.

(3) Includes derivative contracts sold in conjunction with the sales of Cedar Brakes I and II and Mohawk River Funding II and amounts paid in conjunction with the assignment of our Cordova tolling agreement. In connection with the sales of Cedar Brakes I and II and Mohawk River Funding II, we also assigned or terminated a number of our other commodity-based derivatives.

(4) The loss of hedge accounting was a result of a reduction of anticipated production volumes.

Fair Value of Contract Settlements. The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts.

Changes in Fair Value of Contracts. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement, early termination or, if not settled or terminated, until the end of the period.

Assignment of Power Contracts. In December 2005, we entered into an agreement to assign the majority of our power derivative assets to Morgan Stanley. The assignment requires the consent of existing third parties before the contracts can be transferred to Morgan Stanley. Until the assignment is finalized, we entered into offsetting liability contracts with Morgan Stanley to eliminate the commodity price risk associated with the contracts being assigned. We received total proceeds of $442 million to enter into these offsetting contracts and deposited a similar amount of cash margin. The amount we received approximated the value we would have received if we had directly sold our power derivative assets. We anticipate that this assignment will be completed in the first half of 2006.

Results of Operations

Overview

As of December 31, 2005, our operating business segments were Pipelines, Exploration and Production, Marketing and Trading, 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 corporate activities include our general and administrative functions, as well as a telecommunications business and various other contracts and assets.

Our management uses 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 cumulative effect of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated affiliates. Our businesses consist of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries from this measure so that investors may evaluate our operating results independently from our financing methods or capital structure. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

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

	2005	2004	2003
		(In millions)	
Segment			
Pipelines	$ 1,226	$ 1,331	$ 1,234
Exploration and Production	696	734	1,091
Marketing and Trading	(837)	(539)	(809)
Power	(451)	(576)	(40)
Field Services	285	84	129
Segment EBIT	919	1,034	1,605
Corporate and other	(521)	(217)	(852)
Consolidated EBIT	398	817	753
Interest and debt expense	(1,380)	(1,607)	(1,790)
Distributions on preferred interests of consolidated subsidiaries	(9)	(25)	(52)
Income taxes	289	(14)	484
Loss from continuing operations	(702)	(829)	(605)
Discontinued operations, net of income taxes	100	(118)	(1,269)
Cumulative effect of accounting changes, net of income taxes	(4)	—	(9)
Net loss	$ (606)	$ (947)	$(1,883)

The discussions that follow provide additional analysis of the year over year results of each of our business segments, our corporate activities and other income statement items.

Pipelines Segment

Overview

Our Pipelines segment consists of interstate natural gas transmission, storage and LNG terminalling related services, primarily in the United States. We face varying degrees of competition in this segment from other existing and proposed 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 and financial results have historically been relatively stable. However, they 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 2005, 79 percent of our revenues were attributable to reservation charges paid by firm customers. Reservation charges are paid regardless of volumes transported or stored. The remaining 21 percent 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 remarket 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 requirements, 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 five years as of December 31, 2005. Below is the expiration schedule for firm transportation contracts executed as of December 31, 2005, including those whose terms begin in 2006 or later.

	BBtu/d	Percent of Total Available Capacity
2006	4,437	14
2007	5,874	19
2008	2,931	9
2009 and beyond	18,406	58

Operating Results

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

	2005	2004	2003
	(In millions, except volume amounts)		
Operating revenues	$ 2,783	$ 2,651	$ 2,647
Operating expenses	(1,764)	(1,522)	(1,584)
Operating income	1,019	1,129	1,063
Other income	207	202	171
EBIT	$ 1,226	$ 1,331	$ 1,234
Throughput volumes (BBtu/d)[1]			
TGP	4,493	4,519	4,760
EPNG and MPC	4,214	4,235	4,066
ANR	4,100	4,067	4,232
CIG, WIC and CPG	3,641	2,795	2,743
SNG	1,984	2,163	2,101
Equity investments (our ownership share)	2,833	2,798	2,433
Total throughput	21,265	20,577	20,335

(1) Volumes exclude intrasegment activities.

The table below and discussion that follows detail the impact on EBIT of significant events in 2005 compared with 2004 and 2004 as compared with 2003. We have also provided an outlook on events that may affect our operations in the future.

	2005 to 2004				2004 to 2003			
	Revenue	Expense	Other	EBIT Impact	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
Pipeline expansions	$ 82	$ (28)	$(2)	$ 52	$ 33	$ (6)	$ (6)	$ 21
Contract modifications/terminations/settlements	48	—	1	49	(93)	37	—	(56)
Gas not used in operations, revaluations, processing revenues and other natural gas sales	1	(11)	—	(10)	79	(19)	—	60
Hurricanes Katrina and Rita	(13)	(29)	—	(42)	—	—	—	—
General and administrative expense	—	(60)	—	(60)	—	(44)	—	(44)
Operating costs	—	(43)	—	(43)	—	130	—	130
Impairments of pipeline development projects	—	(46)	—	(46)	—	—	—	—
Other regulatory matters	—	(4)	1	(3)	—	(9)	(19)	(28)
Equity earnings from Citrus	—	—	1	1	—	—	22	22
Mexico investments	(2)	—	1	(1)	9	(6)	17	20
Other[1]	16	(21)	3	(2)	(24)	(21)	17	(28)
Total impact on EBIT	$132	$(242)	$ 5	$(105)	$ 4	$ 62	$ 31	$ 97

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

Expansions

During the three years ended December 31, 2005, we completed a number of expansion projects that have generated or will generate new sources of revenues, the more significant of which were our CPG pipeline expansion, our ANR Westleg, Eastleg and Northleg Expansions, our SNG south System Expansions and our TGP South Texas Expansion. The CPG pipeline increased our revenues by $60 million and overall EBIT by $27 million during 2005 compared to 2004. Phase II of the CPG pipeline, which added 181,000 Mcf/d of capacity, was placed in service in December 2005. Overall, our expansions during this time period added approximately 3,253 MMcf/d to our overall pipeline system.

Currently, we have a number of pipeline expansion projects underway, which we are in various stages of certification and approval. The following are those expansion projects that have been approved by the FERC and that have been recently completed or are in various stages of completion:

	Project	Anticipated Completion or In-Service Date	Estimated Cost	Estimated Future Revenues
ANR	Wisconsin 2006	November 2006	$48 million	2006 - $1 million; 2007 - $8 million; Thereafter - $11 million annually
SNG	Elba Island LNG facility	February 2006	$157 million	$29 million annually
WIC	Piceance Basin	March 2006	$132 million	2006 - $11 million; 2007 - $19 million; Thereafter - $21 million annually
CIG	Raton Basin	September and December 2005	$54 million	2006 - $9 million; Thereafter - $13 million annually
TGP	Northeast ConneXion-NY/NJ	November 2006	$39 million	2006 - $2 million; Thereafter - $11 annually
	Triple T	August 2006	$10 million(1)	(2)
	Louisiana Deepwater	October 2006	$11 million	(2)

(1) An additional $8 million of costs will be funded by ANR.

(2) Revenues for these projects will be based on throughput levels as natural gas reserves are developed. We expect these revenues to commence in 2006 for the Triple T expansion and in 2007 for the Louisiana Deepwater Link expansion.

Contract Modifications/Terminations/Settlements

During 2004, we modified, terminated, or settled several contracts on several of our pipeline systems, resulting in a $56 million reduction in EBIT compared with 2003. In 2005, these transactions improved EBIT by $49 million compared with 2004. Below is a further discussion of these significant events:

ANR. In 2005, ANR (i) completed the restructuring of its transportation contracts with one of its shippers on its Southwest and Southeast Legs as well as a related gathering contract, which increased revenues and EBIT by $29 million in 2005 and (ii) settled two transportation agreements previously rejected in the bankruptcy of USGen New England, Inc., which increased EBIT by $15 million but will have no ongoing impact. In 2004, ANR (i) renegotiated or restructured several contracts including its contracts with We Energies, which contributed to the decrease in its revenues by $36 million in 2004 and (ii) terminated the Dakota gasification facility contract on its system, which resulted in lower operating revenues and lower operating expenses during 2004, without a significant overall impact on operating income and EBIT.

EPNG. In 2005, EPNG benefited from the termination of the restrictions in 2004 on remarketing expiring capacity contracts, which increased revenues and EBIT by $5 million during 2005 as compared to 2004. In 2004, EPNG experienced a reduction in revenues of $24 million due to the expiration at the end of 2003 of its historical risk sharing provisions, which had provided revenues, net of a sharing obligation.

In December 2004, Southern California Gas Company (SoCal) acquired approximately 750 MMcf/d of capacity on EPNG's system under new contracts with various terms extending from 2009 to 2011 commencing September 2006. We have executed the relevant transportation service agreements with SoCal. Effective September 2006, approximately 500 MMcf/d of capacity formerly held by SoCal to serve its noncore customers will be available for recontracting. We are remarketing the remaining expiring capacity to serve SoCal's non-core customers or to serve new markets. We are also pursuing the option of using some or all of this capacity to provide new services to existing markets. At this time, we are uncertain how much of this existing capacity will be recontracted, and if so at what rates.

Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales. For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to retain and dispose of according to our tariffs or FERC orders, relative to the amount of gas we use for operating purposes and the price of natural gas. The difference between the amount retained and the amount used in operations results in revenues or expenses to us, which are driven by volumes and prices during a given period. In addition, the timing of these revenues or expenses can vary based on each pipeline's ability to sell or otherwise realize the value of gas not used in operations. The level of retained gas on our systems relative to amounts we use are based on factors such as system throughput, facility enhancements and the ability to operate the pipeline in the most efficient and safe manner. Additionally, several of our pipelines have encroachments against their system gas supply and net imbalances to shippers that are impacted by changing gas prices each period. In 2005, higher gas prices caused an increase in our obligation to replace system gas and settle gas imbalances in the future, resulting in an unfavorable impact on our operating results. Our pipelines also retained lower volumes of gas not used in operations during 2005. These unfavorable impacts were partially offset by the sale of higher volumes of natural gas made available by storage realignment projects in 2005 versus 2004. During 2003 and 2004, higher volumes of gas not utilized for operations and a steadily increasing natural gas price environment resulted in a favorable impact on our operating results in 2004 versus 2003. We anticipate that the overall activity in this area will continue to vary based on factors such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors.

Hurricanes Katrina and Rita. Hurricanes Katrina and Rita had substantial impacts on offshore producers in the Gulf of Mexico Region, resulting in the shut-in of a significant portion of offshore production in the affected areas. In August 2005, Hurricane Katrina resulted in the initial shut-in of approximately 3 Bcf/d of gas supply on our pipeline systems. Prior to Hurricane Rita in September 2005, we had approximately of 1.2 Bcf/d of natural gas supply shut-in. Hurricane Rita resulted in an incremental reduction in supply of approximately 2.9 Bcf/d on our systems. Currently, we have approximately 0.6 Bcf/d of natural gas supply shut-in on our pipeline systems. The timing of these volumes becoming available is dependent on the completion of pipeline and compressor station repairs, the ongoing evaluation of producers' platforms upstream of our pipelines and potential processing constraints if third-party processing facilities are not available. Furthermore, these operational constraints have impacted the efficiency of our pipeline operations. The hurricanes adversely affected our EBIT in the fourth quarter of 2005 by $42 million because of their impact on certain usage revenues, estimated unreimbursed repair costs, increased operating costs and lost revenues associated with reductions in service. The adverse effect on our results may continue into early 2006.

General and Administrative Expenses During the year ended December 31, 2005, our general and administrative costs were higher than in 2004, primarily due to an increase in direct payroll related benefits for our employees of $42 million, higher legal and insurance costs of $14 million, and higher corporate overhead allocations from El Paso of $2 million. El Paso's allocation to us increased in 2005 based on the estimated level of resources devoted to our segment's operations and the relative size of our EBIT, gross property and payroll as compared to the consolidated totals.

Operating Costs. Over the past two years, we incurred higher costs for compressor engine repair and preventative maintenance, lowering of lines and pipeline integrity testing. Additionally, in 2005 we recorded higher legal and environmental reserves. In 2003, El Paso finalized the Western Energy settlement and EPNG recorded charges of $140 million in operating expenses related to this settlement.

Beginning in 2006, we will be required under a FERC accounting release to expense certain costs incurred in connection with our pipeline integrity programs, instead of our current practice of capitalizing them as part of our property, plant and equipment. We currently estimate that we will be required to expense an additional amount of pipeline integrity costs under this accounting release in the range of approximately $26 million to $41 million annually.

Impairments of Pipeline Development Projects. During the fourth quarter of 2005, we discontinued a portion of our Seafarer project and the entirety of our Blue Atlantic development project due to changing market conditions.

Other Regulatory Matters. The following discussion describes certain regulatory matters that have impacted our operations or will have an impact on our operations beginning in 2006.

In 2003, we re-applied 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 requires a company to capitalize items that will be considered in future rate proceedings. Upon re-application, we recorded $18 million in income resulting 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 annual increase in depreciation expense of approximately $9 million. 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.

Rate Cases. 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 positively or negatively impact our profitability. Currently, certain of our pipelines have no requirements to file new rate cases and expect to continue operating under their existing rates. However, certain other pipelines listed below are currently in rate proceedings or have upcoming rate actions.

- EPNG — Filed a rate case in June 2005 proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates and also proposing new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. On January 1, 2006, the rates, which are subject to refund, and the fuel tracking mechanism became effective. Additionally, settlement discussions with major customers are underway and implementation of new services is scheduled for April 1, 2006.
- CIG — Will be required to file for new rates to be effective in the fourth quarter of 2006.
- MPC — Is expected to file for new rates that would be effective March 2007.

Exploration and Production Segment

Overview

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment 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.

We manage this business with the goal to create shareholder value through disciplined capital allocation, cost control and portfolio management. Our natural gas and oil reserve portfolio blends slower decline rate, typically longer lived assets in our Onshore region with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. We believe the combination of our assets in these regions provides significant near-term cash flow while providing consistent opportunities for high-return investments. During the past two years, we have dedicated substantial resources and management effort to stabilizing and improving this business. We believe this effort has been largely successful. Our efforts have been focused on the following:

Goal or Strategy	Actions Taken	Results
Improve capital discipline and returns	Created a standard economic measure known as PVR (present value ratio) to evaluate project success. This ratio represents the present value of future after-tax cash flows discounted at 12% over total investment. Our target ratio is 1.15, which simply means that every $1.00 invested returns $1.15 on an after-tax, discounted basis over the life of the project. A rigorous post-spending analysis is prepared and a monthly scorecard for each operating region is evaluated by management.	Our 2005 actual post-drill PVR was 1.19 using a $4.75/MMBtu plan price compared to our pre-drill PVR target of 1.23. Our PVR was 2.11 using 2005 realized prices with the year-end strip prices thereafter.
Improve portfolio management	Allocated a greater percentage of capital expenditures to onshore exploration and development opportunities. Acquired Medicine Bow to expand our presence in the Rockies and east Texas and GMT Energy Corporation to expand our presence in east Texas. Divested certain high cost onshore and offshore properties with high abandonment liabilities and only 25 Bcfe of proved reserves. Implemented a consistent risk analysis process and reduced capital exposure to deep drilling. Utilized comprehensive mapping with life-of-property exploitation plans.	Our onshore reserves increased from 55 percent of our total reserves at year end 2004 to 60 percent of our total reserves at year end 2005. Our unconventional coal seam reserves comprise approximately one third of our total reserve base. These longer-life reserves form a stable production base and should make our business more predictable. The Medicine Bow acquisition accelerated the changes in our portfolio since over 80 percent of the proved reserves overlap with our core onshore areas.
Improve our production mix	Increased our onshore production through drilling activities and our acquisition program, including the acquisition of our equity investment in Four Star.	From 2004 to 2005, total onshore production grew as a percentage of total production. A substantial portion of the increase was organic growth as opposed to acquisitions.
Grow our reserves base	Created a balanced acquisition and drilling program that focused on increasing long life reserves while converting proved undeveloped reserves (PUD) to producing developed reserves.	During 2005, we produced 271 Bcfe (excluding our equity share of Four Star production of 9 Bcfe) while our drilling and acquisition programs generated net additions of 505 Bcfe (excluding our equity share of Four Star of 262 Bcfe). We also increased our reserves over production ratio from 7.2 years to 8.9 years. In 2005, we developed 22 percent of our total 2004 year-end PUD reserves.

Goal or Strategy	Actions Taken	Results
Build an inventory of attractive lower risk drilling prospects	Improved our ability to grow by creating a regional structure that leverages a strong acreage position in key producing basins. Utilized detailed mapping and reservoir analysis and a standardized risk measurement system to identify drilling and workover or recompletion opportunities. Completed $1.1 billion of acquisitions that complement our existing core operations.	Identified 629 wells to be drilled in 2006 with 2,620 more in future years at a $5.50/MMBtu price forecast for natural gas that generates a PVR of 1.15 or greater. Created a balanced inventory along the entire risk spectrum with low risk development prospects coupled with high potential offshore exploration and international oil opportunities.

Significant Operational Factors Affecting the Year Ended December 31, 2005

- *Higher realized prices.* We benefited from a strong commodity pricing environment in 2005. Realized natural gas prices, which include the impact of our hedges, increased 10 percent while oil, condensate and NGL prices increased 32 percent compared to 2004.

- *Average daily production of 743 MMcfe/d (excluding 24 MMcfe/d from our equity investment in Four Star).* Our average daily equivalent production decreased from 2004 primarily due to several hurricanes in the Gulf of Mexico, which caused us to shut in significant volumes in our Gulf of Mexico and south Louisiana region. We have continued to increase production volumes in our Onshore region as a result of our successful drilling and acquisition programs. However, production volumes in our Gulf of Mexico and south Louisiana region, adjusted for the impact of hurricanes, and Texas Gulf Coast region continued to gradually decrease as drilling programs and overall lower capital spending in those areas have not been sufficient to offset the historically steep production decline rates in these regions.

- *Impact of hurricanes on production volumes.* The Gulf Coast hurricanes negatively impacted our annual production by approximately 12 Bcfe or 34 MMcfe/d during 2005. Prior to Hurricane Katrina in late August 2005, our production from the Gulf of Mexico was about 205 MMcfe/d. A substantial portion of our shut-in production from Hurricane Katrina was brought back online during September 2005 to a level of about 170 MMcfe/d just prior to Hurricane Rita. We continue to experience substantial shut-in volumes from Hurricane Rita; however, Gulf of Mexico production levels have returned to approximately 130 MMcfe/d at December 31, 2005 and currently remain at that level. We expect the majority of the remaining operated Gulf of Mexico production to come back online during the first half of 2006. Also impacted were our onshore Texas Gulf Coast and Arklatex areas, where damage from Hurricane Rita initially impacted approximately 60 MMcfe/d of production. However, production was restored within a few days of the event.

- *Drilling results.* In 2005, we participated in drilling a total of 483 gross wells with a 99 percent success rate and a PVR of 1.19 based on a plan price of $4.75/MMBtu. Our drilling results by region were as follows:

  Onshore region. We experienced a 99 percent success rate on 454 gross wells drilled during 2005, resulting in production growth in the Rockies, Raton, north Louisiana and Arkoma operating areas.

  Texas Gulf Coast region. We experienced significant improvement in the second half of the year achieving an 89 percent success rate on 18 gross wells drilled during 2005. New Wilcox production was established from exploration at the Renger Field in Lavaca County, Texas. In addition, the shallow Vicksburg development program in Starr and Hidalgo Counties, Texas provided consistent results adding production on existing base properties.

  Gulf of Mexico and south Louisiana region. Overall, we experienced a 73 percent success rate on 11 gross wells drilled during 2005. During the year, we announced our participation in two deep shelf discovery wells at West Cameron Blocks 75 and 62 in the Gulf of Mexico. These projects are expected to come on line during the first quarter of 2006 and produce 20 MMcfe/d or higher, net to our interest. We also participated in a third discovery in 2005 through a 25 percent working interest in a well drilled at Long Point in Vermillion Parish, Louisiana, which tested at over 40 MMcfe/d, and is expected to come on line during the second quarter 2006.

Outlook for 2006

For 2006, we also expect:

- Capital expenditures of approximately $1 billion, excluding acquisitions;

- Average daily production volumes for the year of approximately 755 MMcfe/d to 780 MMcfe/d, which excludes approximately 70 MMcfe/d from our equity interest in Four Star. Our daily production volumes in Brazil averaged approximately 53 MMcfe/d during 2005. Our Brazilian production was reduced by about 30 MMcfe/d in February 2006 due to a contractual decrease in our interest from 79 percent to 35 percent in UnoPaso's production in Brazil as a result of achieving payout;

- Average cash operating costs of approximately $1.64/Mcfe to $1.71/Mcfe for the year;

- Domestic unit of production depletion rate of $2.22/Mcfe in the first quarter of 2006. This compares to $2.16/Mcfe in the fourth quarter of 2005. The increase is expected due to higher finding and development costs and the costs of acquired reserves;

- Brazilian unit of production depletion rate of $1.96/Mcfe in the first quarter of 2006. This compares to $2.39/Mcfe in the fourth quarter of 2005; and

- Significant industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs and a mitigation effort designed to manage and improve field efficiency.

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. Our Marketing and Trading segment has also entered into other derivative contracts that are designed to provide price protection to the overall company, which is discussed further in that segment's operating results. Our hedging positions are regularly monitored by senior management and a committee of the Board of Directors. Because this 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. Adjustments to our hedging strategy and the decision to enter into new positions or to alter existing positions are made at the corporate level based on the goals of the overall company.

During 2005, we experienced a significant decrease in the fair value of our hedging derivatives. These fair value decreases were generally deferred in our accumulated other comprehensive income and will be recognized in our income at the time the production volumes to which they relate are sold. As of December 31, 2005, the fair value of the positions deferred in accumulated other comprehensive income was a pretax loss of $492 million. This deferred amount will be recognized in income upon the settlement of these derivative commodity instruments, but will be substantially offset by the impact of the corresponding change in the price to be received when the hedged natural gas production is sold. This will result in a realized price that is approximately equal to the hedged price if settled as originally anticipated.

Below are the hedging positions on our anticipated natural gas and oil production as of December 31, 2005:

Natural Gas

	Quarter Ended									
	March 31		June 30		September 30		December 31		Total	
	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)
2006[1]	21,349	$7.07	21,367	$6.01	21,385	$6.01	21,385	$6.28	85,486	$6.34
2007	1,579	$3.79	1,447	$3.64	1,155	$3.35	1,155	$3.35	5,336	$3.56
2008	1,142	$3.35	1,142	$3.35	1,155	$3.49	1,155	$3.49	4,594	$3.42
2009 to 2012									16,026	$3.74

(1) The hedged natural gas prices in the table represent the price on the hedge contract when it was entered into or the price on the day it was designated as a hedge. The average cash prices to be received under these hedge contracts when they settle is approximately $3.95 per MMBtu for each of the quarters ended March 31, June 30, September 30 and December 31, 2006 and the year ended December 31, 2006.

Oil. We also have derivative contracts on our Brazilian oil production that provide us with a fixed price of $35.15 per Bbl on approximately 96 MBbls per quarter in 2006 and approximately 48 MBbls per quarter in 2007. Our 2007 derivative positions are accounted for as hedges and will be recognized in income as the positions settle, while changes in the fair value of the 2006 positions will be recognized in income as market prices change.

Operating Results

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

	2005	2004	2003
	(In millions, except volumes and prices)		
Operating Revenues:			
Natural gas	$ 1,420	$ 1,428	$ 1,831
Oil, condensate and NGL	371	305	305
Other	(4)	2	5
Total operating revenues	1,787	1,735	2,141
Transportation and net product costs[1]	(47)	(54)	(82)
Total operating margin	1,740	1,681	2,059
Operating Expenses:			
Depreciation, depletion and amortization	(612)	(548)	(576)
Production costs[2]	(261)	(210)	(229)
General and administrative expenses	(185)	(173)	(160)
Other	(11)	(24)	(21)
Total operating expenses[1]	(1,069)	(955)	(986)
Operating income	671	726	1,073
Other income[4]	25	8	18
EBIT	$ 696	$ 734	$ 1,091

	2005	Percent Variance	2004	Percent Variance	2003
Consolidated volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	222,292	(9)%	244,857	(28)%	338,762
Average realized prices including hedges ($/Mcf)[3]	$ 6.39	10%	$ 5.83	8%	$ 5.40
Average realized prices excluding hedges ($/Mcf)[3]	$ 7.53	28%	$ 5.90	7%	$ 5.51
Average transportation costs ($/Mcf)	$ 0.18	6%	$ 0.17	(6)%	$ 0.18
Oil, condensate and NGL					
Volumes (MBbls)	8,136	(8)%	8,818	(25)%	11,778
Average realized prices including hedges ($/Bbl)[3]	$ 45.60	32%	$ 34.61	33%	$ 25.96
Average realized prices excluding hedges ($/Bbl)[3]	$ 46.43	34%	$ 34.75	30%	$ 26.64
Average transportation costs ($/Bbl)	$ 0.63	(44)%	$ 1.12	7%	$ 1.05
Total equivalent volumes (MMcfe)	271,107	(9)%	297,766	(27)%	409,432
Production costs ($/Mcfe)					
Average lease operating costs	$ 0.72	20%	$ 0.60	43%	$ 0.42
Average production taxes	0.24	118%	0.11	(21)%	0.14
Total production cost[2]	$ 0.96	35%	$ 0.71	27%	$ 0.56
Average general and administrative cost ($/Mcfe)	$ 0.68	17%	$ 0.58	49%	$ 0.39
Unit of production depletion cost ($/Mcfe)	$ 2.10	24%	$ 1.69	29%	$ 1.31
Unconsolidated affiliate volumes (Four Star)[4]					
Natural gas (MMcf)	6,689				
Oil, condensate and NGL (MBbls)	359				
Total equivalent volumes (MMcfe)	8,844				

(1) Transportation and net product costs are included in operating expenses on our consolidated statement of income.

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

(3) Prices are stated before transportation costs.

(4) Includes equity earnings and volumes for our investment in Four Star. Our equity interest in Four Star was acquired in connection with our acquisition of Medicine Bow in August 2005.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Our EBIT for 2005 decreased $38 million as compared to 2004. The table below lists the significant variances in our operating results in 2005 as compared to 2004:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 362	$ —	$—	$ 362
Lower volumes in 2005	(133)	—	—	(133)
Impact of hedges	(237)	—	—	(237)
Oil, Condensate and NGL Revenue				
Higher realized prices in 2005	95	—	—	95
Lower volumes in 2005	(24)	—	—	(24)
Impact of hedges	(5)	—	—	(5)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2005	—	(110)	—	(110)
Lower production volumes in 2005	—	45	—	45
Production Costs				
Higher lease operating costs in 2005	—	(17)	—	(17)
Higher production taxes in 2005	—	(34)	—	(34)
General and Administrative Expenses	—	(12)	—	(12)
Other				
Earnings from investment in Four Star	—	—	19	19
Other	(6)	14	5[1]	13
Total Variances	$ 52	$(114)	$24	$ (38)

[1] Consists primarily of changes in transportation costs and other income.

Operating revenues. During 2005, we continued to benefit from a strong commodity pricing environment for natural gas and oil, condensate and NGL. However, losses in our hedging program for the year ended December 31, 2005 were $260 million compared to $18 million in 2004. Additionally, we experienced a nine percent decrease in production volumes versus the same period in 2004. Although our production volumes benefited from the acquisitions in 2005 and our acquisition and consolidation of the remaining interest in UnoPaso in Brazil in July 2004, our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions experienced declines in year over year production due to normal declines and a lower capital spending program in these areas over the last several years. In addition, the Gulf of Mexico and south Louisiana region was impacted by the hurricanes discussed previously, while the Texas Gulf Coast region was impacted by mechanical well failures.

Depreciation, depletion and amortization expense. During 2005, we experienced higher depletion rates compared to 2004 as a result of higher finding and development costs and the cost of acquired reserves which resulted in higher depreciation, depletion and amortization expense. However, during 2005, the impact of lower production volumes partially offset the impact of our higher depletion rates.

Production costs. We continued to experience higher costs in 2005 due to the implementation of programs in the first half of 2005 to improve production in the Texas Gulf Coast and Gulf of Mexico and south Louisiana regions, higher salt water disposal costs, utility expenses, marine transportation costs and increased operating costs in Brazil due to our July 2004 UnoPaso acquisition and consolidation. Production taxes were also higher as the result of higher commodity prices in 2005 and higher tax credits taken in 2004 on high cost natural gas wells.

General and administrative expenses. Our general and administrative expenses were higher in 2005 than in 2004, primarily due to an increase in direct payroll related benefits for our employees, and higher legal and insurance costs.

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

Our EBIT for 2004 decreased $357 million as compared to 2003. The table below lists the significant variances in our operating results in 2004 as compared to 2003:

	Variance			
	Operating Revenue	Operating Expense	Other[1]	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Lower volumes in 2004	$(518)	$ —	$—	$(518)
Higher realized prices in 2004	96	—	—	96
Impact of hedges	19	—	—	19
Oil, Condensate and NGL Revenue				
Lower volumes in 2004	(79)	—	—	(79)
Higher realized prices in 2004	72	—	—	72
Impact of hedges	7	—	—	7
Depreciation, Depletion and Amortization Expense				
Lower production volumes in 2004	—	146	—	146
Higher depletion rate in 2004	—	(115)	—	(115)
Production Costs				
Higher lease operating costs in 2004	—	(8)	—	(8)
Lower production taxes in 2004	—	27	—	27
General and Administrative Expenses	—	(13)	—	(13)
Other	(3)	(6)	18	9
Total Variances	$(406)	$ 31	$18	$(357)

(1) Other consists of changes in transportation costs and other income.

Operating Revenues. During 2004, we experienced a significant decrease in production volumes. The decline in our natural gas volumes was due to normal production declines in the Texas Gulf Coast and Gulf of Mexico and south Louisiana regions, asset sales, lower capital expenditures and disappointing drilling results. These declines were partially offset by increased natural gas production in our coal seam operations in the Raton, Arkoma and Black Warrior basins. We also had increased oil production in Brazil in 2004 as a result of our acquisition of the remaining interest and consolidation of UnoPaso. In addition, we encountered 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 $18 million in 2004 as compared to $44 million in 2003.

Depreciation, depletion and amortization expense. Lower production volumes in 2004 due to production declines 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 gross workover costs due to the implementation of programs in the second half of 2004 to improve production in the Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. We also incurred higher utility expenses and higher salt water disposal costs in the Onshore region. However, more than offsetting these increases were lower production taxes as a result of higher tax credits taken in 2004 on high cost natural gas wells.

General and administrative expenses. Higher contract labor costs and lower capitalized costs were the main factors leading to the increase in general and administrative expenses in 2004.

Marketing and Trading Segment

Our Marketing and Trading segment's primary focus is to market our Exploration and Production segment's natural gas and oil production and to manage the company's overall price risks, primarily through the use of natural gas and oil derivative contracts. Historically this segment has also managed a portfolio of power derivatives and contracts, as well as other structured commodity-based transactions. In the fourth quarter of 2005, we entered into transactions to assign a majority of our power contracts to third parties, including our Cordova tolling agreement.

The following is a summary of our remaining contracts and their sensitivity to changes in commodity prices as of December 31, 2005:

Contract Type	Description	Status	Expected Earnings Volatility
Mark-to-Market			
Production-related natural gas and oil derivatives	Option contracts with various floor and ceiling prices; fixed-for-float swaps.	Significantly impacted our results in 2005 due to changes in natural gas and oil prices and may continue to do so if volatility continues in the future.	High
Power	PJM basis positions.	Impacted by changes in regional power prices in 2005 and may continue to be impacted if volatility continues.	Moderate
	Power supply contracts.	Entered into positions in December 2005 to substantially eliminate price risk associated with these contracts.	Low
Other natural gas	Fixed-price, physical delivery contracts; fixed-for-float swaps.	Terminated or assigned a significant number of contracts in recent years and anticipate additional assignments in 2006, which will result in further reduction in exposure.	Low
Accrual			
Transportation-related	Pipeline capacity contracts.	Experienced significant losses historically due to regional changes in natural gas prices. Significant expirations in 2006 and 2015 will reduce our exposure.	Low
Long-term gas supply obligations	Supply contracts with delivery obligations up to 1 Bcf/d.	Approximately 90 percent of obligations are index-priced and remaining fixed price obligations are hedged.	Low

While we continue to evaluate potential opportunities to assign or otherwise divest of contracts related to our legacy trading operations, we may not liquidate certain of these remaining transactions before their expiration if (i) they are either uneconomical to sell or terminate in the current environment due to their terms, credit concerns of the counterparty or lack of liquidity in the market or (ii) a sale would require an acceleration of cash demands. Any future liquidations may impact our cash flows and financial results. The discussion that follows provides additional analysis of the contracts held by our Marketing and Trading segment.

Production-related Natural Gas and Oil Derivatives

During 2004 and 2005, we entered into option contracts that provide El Paso with various floor and ceiling prices on a portion of its anticipated natural gas production in 2006 through 2009 and oil production in 2007 and 2008. We paid a total premium of $144 million for our floors and received a $50 million premium for our ceilings. We also maintain swaps that obligate us to sell natural gas and oil at fixed prices. As of December 31, 2005, our contracts were as follows:

		Swaps[1]		Floors[1]		Ceilings[1]	
Natural Gas		Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
	2006	25	$ 8.11	120	$ 7.00	60	$ 9.50
	2007	—	—	51	$ 6.41	21	$ 9.00
	2008	—	—	18	$ 6.00	18	$10.00
	2009	—	—	17	$ 6.00	17	$ 8.75
Oil							
	2006	1,044	$58.81	—	—	—	—
	2007	—	—	1,009	$55.00	1,009	$60.38
	2008	—	—	930	$55.00	930	$57.03

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

For a combined discussion of the cash prices under these contracts and contracts held by our Exploration and Production segment, see Liquidity discussion on page 40.

Contracts Related to Legacy Trading Operations

Natural gas contracts. These contracts primarily relate to our transportation activities. Specifically, these contracts provide us with approximately 1.5 Bcf of pipeline capacity per day, on which we will be charged approximately $140 million in annual demand charges in 2006 and, on average, $111 million in each of the years 2007 through 2010. The recovery of these charges, and therefore the profitability of these contracts, is dependent upon our ability to use the contracted pipeline capacity, which is impacted by a number of factors including differences in natural gas prices at contractual receipt and delivery locations, the working capital needed to use this capacity and the capacity required to meet our other long term obligations. These transportation contracts are accrual-based and impact our gross margin as delivery or service under the contracts occurs.

In addition to these transportation-related contracts, we have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices. Our remaining long-term contracts require us to sell natural gas to various power plants and have expiration dates ranging from 2009 to 2028.

During the first quarter of 2006, we assigned our contracts to supply natural gas to the Jacksonville Electric Authority and The City of Lakeland, Florida for no cash consideration. We will record a gain of approximately $50 million related to this assignment in 2006.

Power Contracts. As of December 31, 2005, our primary remaining exposure in our power portfolio is for locational differences in power prices between eastern PJM and the west PJM hub through 2016.

We have several contracts that obligate us to deliver power or manage the risk associated with our obligations to deliver power, including those related to UCF. In December 2005, we entered into contracts to substantially offset the price risk associated with these power supply and power price risk management contracts. We will assign or terminate a portion of these contracts in 2006; however, we will retain some contracts (including those related to UCF) that will present minimal price risk to us in the future as any exposure is largely offset by the new contracts we entered into in December 2005.

Operating Results

As a result of substantial changes in the composition of our portfolio over the past three years, year-to-year comparability in our operating results was affected. The tables below and the discussion that follows provide the overall operating results and analysis for our Marketing and Trading segment and factors by significant contract type that affected the profitability of our Marketing and Trading segment during each of the three years ended December 31:

	2005	2004	2003
		(In millions)	
Overall EBIT:			
Gross margin[1]	$(796)	$(508)	$(636)
Operating expenses	(59)	(54)	(183)
Operating loss	(855)	(562)	(819)
Other income, net	18	23	10
EBIT	$(837)	$(539)	$(809)

	2005	2004	2003
		(In millions)	
Gross Margin by Significant Contract Type:			
Production-Related Natural Gas and Oil Derivatives			
Changes in fair value of options and swaps	$(436)	$ 53	$ —
Changes in fair value of other derivatives	—	(439)	(425)
Gross margin	(436)	(386)	(425)
Contracts Related to Legacy Trading Operations			
Natural gas contracts:			
Transportation-related contracts:			
Demand charges	(156)	(151)	(177)
Settlements[2]	121	87	18
Changes in fair value of other natural gas derivative contracts	39	44	(6)
Power contracts:			
Changes in fair value of Cordova tolling agreement	(136)	(36)	75
Change in fair value of other power derivatives	(250)	(85)	(96)
Other	22	19	(25)
Gross margin	(360)	(122)	(211)
Total gross margin	$(796)	$(508)	$(636)

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

(2) Includes a $50 million gain in 2004 related to the early termination of an LNG contract and a $17 million loss in 2003 related to the early termination of a storage contract.

Production-related Natural Gas and Oil Derivative Contracts

Options and swaps. The fair value of our production-related option and swap contracts declined in 2005 due to increases in natural gas and oil prices, and as a result, we experienced significant losses. If natural gas and oil prices remain above the floor prices of our option contracts, these contracts will remain unexercised and will expire without any value. For our ceiling contracts, if natural gas and oil prices continue to increase, further losses will occur since we are obligated under these contracts to provide natural gas and oil at fixed prices that are currently lower than the market price.

Other production-related derivatives. In 2004 and 2003, our losses were a result of increases in natural gas prices relative to fixed priced commodity contracts held at the time. In the fourth quarter of 2004, we designated those contracts as accounting hedges and transferred them to our Exploration and Production segment. As a result, the income impacts of those contracts are now reflected in our Exploration and Production segment results.

Contracts Related to Legacy Trading Operations

Natural Gas Contracts

Transportation-related contracts. During 2005, our ability to use our transportation-related contracts improved due to increased price differentials between the receipt and delivery points for these contracts. The following table is a summary of our demand charges (in millions) and our percentage of recovery of these charges for each of the three years ended December 31:

	2005	2004	2003
Alliance:			
Demand charges	$65	$61	$56
Recovery	93%	72%	74%
Enterprise Texas:			
Demand charges	$26	$27	$23
Recovery	8%	2%	—[1]
Other:			
Demand charges[2]	$65	$63	$98
Recovery	94%	38%	8%

(1) In 2003, we were unable to recover demand charges and incurred $13 million in losses in excess of the demand charges related to managing the capacity under these contracts.

(2) Includes demand charges related to storage contracts of $1 million, $2 million, and $21 million in 2005, 2004, and 2003.

Other natural gas derivative contracts. Our exposure to the volatility of gas prices as it relates to our other natural gas derivative contracts varies from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Because we had the right to purchase more natural gas at fixed prices than we had the obligation to sell under these contracts during 2003, 2004 and 2005, the fair value of these contracts increased as natural gas prices increased during those years. However, the increase in 2003 was more than offset by losses associated with the early termination of a number of these contracts resulting in an overall loss for the year.

Under certain of these contracts, we supply gas to power plants that we partially own, including the Midland Cogeneration Venture (MCV) and Berkshire power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these contracts to the extent of our ownership interest. However, should we sell our interests in these plants, we would record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $146 million as of December 31, 2005.

Power Contracts

During 2005, we divested or entered into transactions to divest of a substantial portion of our power contracts, including our (i) Cordova tolling agreement, (ii) substantially all contracts in our power portfolio and (iii) certain other contracts related to our Power segment's historical power contract restructuring business. The discussion that follows details significant factors impacting our power contracts during 2005, 2004 and 2003.

Cordova tolling agreement. In the fourth quarter of 2005, we completed the assignment of this agreement to Constellation. Prior to this assignment, we experienced significant volatility under this agreement, which was sensitive to changes in forecasted natural gas and power prices. During 2004 and 2005 forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract. However, during 2003, forecasted power prices increased relative to natural gas prices, resulting in a significant increase in the fair value of this contract.

Other power derivatives. Historically, many of our contract origination activities related to power contracts. However, in 2003, we began exiting our power contract origination activities due to changes in the energy trading environment and re-aligning the focus of our Marketing and Trading segment. Our activity in this area was as follows:

- During 2005, 2004 and 2003, we supplied power to Morgan Stanley under a power supply agreement related to our formerly-owned UCF entity. We were also required to purchase power under a number of other power agreements, which included those used to manage our risk on the power supply obligation to Morgan Stanley. As a result of increasing power prices and increases in the differences in power prices at various locations in PJM, our Morgan Stanley contract decreased in fair value by $345 million, $72 million and $77 million in 2005, 2004 and 2003. These decreases were partially offset by increases in the fair value of our power purchase contacts of $223 million, $81 million and $48 million in 2005, 2004 and 2003.

  In addition to our Cordova assignment, we entered into an agreement in December 2005 to assign the majority of our remaining power portfolio to Morgan Stanley. This assignment includes all of our remaining power derivative assets, except for certain positions in the PJM power pool that we will retain. The assignment requires consents by the current counterparties to the contracts. Until the assignment is finalized, we entered into new offsetting liability contracts with Morgan Stanley for the power portfolio being assigned, which eliminated our cash and earnings exposure to power price movements for these contracts. We received total proceeds of $442 million to enter into these offsetting contracts and deposited a similar amount of cash margin. The amount we received approximated the value we would have received if we had directly sold our power derivative assets.

- *Contracts related to our former power contract restructuring activities.* During the first quarter of 2005, we assigned our contracts to supply power to our Power segment's Cedar Brakes I and II entities to Constellation. We recorded a loss of $30 million in 2004 related to entering into an agreement to assign these contracts. In 2004 and 2003, these contracts decreased in fair value by $64 million and $67 million. In conjunction with the assignment, we also entered into derivative contracts with Constellation that swap the locational differences in power prices at several power plants in eastern PJM and the west PJM hub through 2013. Due to unfavorable changes in the power prices at each location, the fair value of these swaps decreased by $105 million during 2005.

  During the fourth quarter of 2005, we assigned our contracts to supply power to our Power segment's Mohawk River Funding II subsidiary to Merrill Lynch. We recognized a loss of $23 million associated with this assignment. As a result of this assignment, we have no further obligations to provide power to our Power segment.

Other. During 2005, a bankruptcy court entered an order allowing Mohawk River Funding III's (MRF III) bankruptcy claims with USGen New England. We received payment on this claim and recognized a gain of $17 million in 2005 related to this settlement. During 2004, we recorded a $25 million gain related to the termination of a power contract with our Power segment, which was eliminated in El Paso's consolidated results.

Operating Expenses

During 2005, our Marketing and Trading segment recorded $18 million of legal settlements and reserves, which resulted in increased operating expenses. However, this amount was partially offset by a decline in general and administrative expenses. Overall operating expenses have decreased significantly from 2003 due primarily to the following:

- Recording $26 million of charges in operating expenses in 2003 related to the Western Energy Settlement prior to the transfer of this obligation to our corporate operations.
- Recording bad debt expense associated with a fuel supply agreement we have with the Berkshire power plant of $2 million, $10 million and $28 million in 2005, 2004 and 2003.
- Incurring lower corporate overhead allocation and general and administrative expenses based on overall cost reduction efforts at the corporate level and our reduced level of operations in 2004 and 2005. These reductions were primarily due to a reduction of our trading activities coupled with the closing of our office in London in 2003.

Power Segment

As of December 31, 2005, our Power segment primarily consisted of an international power business in Brazil. Substantially all of our other international power assets, primarily in Asia and Central America, are under sales agreements and are expected to close in the first half of 2006. Over the past several years, we also had substantial domestic power operations, including a portfolio of domestic power plants and a power contract restructuring business. Substantially all of these domestic operations have been sold or fully impaired.

As of December 31, 2005, the total financial exposure on our investments in Brazil was approximately $858 million. Based on the status of negotiations and disputes in certain of these projects, it is possible that additional impairments of these assets may occur in the future. Below is a further discussion of these matters, which are further described in Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

- *Macae.* Our Macae power plant sells a majority of its power to the wholesale Brazilian power market. Macae also has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras has not made payments under the contract since December 2004 and initiated arbitration proceedings related to that obligation. In early 2006, we signed a memorandum of understanding to resolve the arbitration proceedings and sell Macae to Petrobras for approximately $358 million. The completion of the sale of Macae is subject to the negotiation of a definitive purchase and sale agreement, and approvals by Brazilian regulators. As a result of the dispute and the indication of value we would receive for the potential sale of the plant, we recorded impairments of $351 million in 2005. Depending on the terms of the final agreement, we could be required to record additional losses related to the disposition and the resolution of disputes related to Macae.
- *Porto Velho.* The Porto Velho plant sells power to Eletronorte under two power sales agreements that expire in 2010 and 2023. Eletronorte absorbs substantially all of the plant's fuel costs and purchases all of the energy and capacity sold by the plant, provided that the plant operates within certain operational requirements. As a result, the profitability of the plant is dependent primarily on meeting the operational requirements of the contract and through efficient operations and maintenance practices. In October 2004, our Porto Velho project experienced an outage with its steam turbine, which resulted in a partial reduction in the plant's capacity. The project expects to have the steam turbine back in service in the first quarter of 2006. In addition, the project is also currently negotiating certain provisions of its power purchase agreement and the outcome of these negotiations may impact the future financial performance of the project.
- *Manaus and Rio Negro.* In January 2005, we signed new power sales contracts for our Manaus and Rio Negro power plants with Manaus Energia. Under these new contracts, Manaus Energia will pay a price for its power that is similar to that in the previous contracts. In addition, Manaus Energia will assume ownership of the plants in 2008.

• *Other.* At our Araucaria power plant, the power sales contract is currently in international arbitration due to non-payment by the utility that purchases power from the plant. In early 2006, we signed a letter of intent to resolve the arbitration proceedings and to sell our investment in Araucaria to COPEL for $190 million. We also have an interest in two pipelines which reached full capacity in 2003 and currently generate income through the transportation of natural gas to various customers in South America.

Operating Results

The tables below and discussions that follow provide the operating results and additional analysis of our Power segment operations for the years ended December 31:

	2005	2004	2003
		(In millions)	
Overall EBIT:			
Gross margin[1]	$ 110	$ 525	$ 753
Operating expenses	(539)	(921)	(773)
Operating loss	(429)	(396)	(20)
Losses from unconsolidated affiliates	(139)	(249)	(91)
Other income	117	69	71
EBIT	$(451)	$(576)	$ (40)
EBIT by Area:			
Brazil			
Impairments			
Macae	$(351)	$ —	$ —
Manaus and Rio Negro	—	(183)	—
EBIT from operations	44	235	177
Other International Power			
Asia			
Impairments related to anticipated sales	(87)	(182)	—
Gain on sale of KIECO, PPN and Chinese plants	131	—	—
EBIT from operations	15	64	47
Central and other South America			
Impairments related to anticipated sales	(89)	—	—
Gain on sale of Argentina	—	—	28
EBIT from operations	5	1	8
EBIT from other international plants and investments	14	(1)	24

	2005	2004	2003
		(In millions)	
Domestic Power			
Midland Cogeneration Venture	(162)	(171)	29
Other impairments, net[2]			
Sale of interest in Cedar Brakes I and II and UCF and related power restructuring contracts	—	(324)	(15)
Decline in value of Chaparral investment	—	—	(207)
Milford receivable write-off due to lender dispute	—	—	(88)
Other domestic plants and investments	(5)	(105)	(208)
Proceeds from portion of MRF III bankruptcy claim previously written off	53	—	—
EBIT from operations	—	143	256
Other[3]	(19)	(53)	(91)
EBIT	$(451)	$(576)	$ (40)

(1) Gross margin for our Power segment consists of revenues from our power plants and the 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.

(2) Includes impairment charges and gains (losses) on the sales of assets and investments.

(3) Includes impairments and losses on the sales of power turbines of $27 million, $1 million and $33 million in 2005, 2004 and 2003. Also includes $40 million of gains on the sales of cost basis investments in 2005.

Brazil

During 2002 and 2003, we completed the construction of several power plants and pipelines, which allowed them to reach full operational capacity. However, our financial results during 2004 and 2005 were impacted significantly by regional economic and political conditions, which affected the renegotiation of several of the power contracts for our Brazilian power plants including those related to Macae, Manaus and Rio Negro.

Macae. At our Macae facility, we entered into a memorandum of understanding in February 2006 to resolve our disputes with and sell the plant to Petrobras. During 2005, we recorded significant impairments based on our expected outcome of the negotiations with Petrobras. EBIT from our Macae plant's operations was a loss of $13 million in 2005, income of $172 million in 2004, and income of $156 million in 2003. The 2005 decrease was due to the non-recognition of $206 million of revenues based on non-payment of minimum revenue amounts by Petrobras.

Porto Velho. EBIT from our Porto Velho plant's operations was $23 million, $28 million and $28 million in 2005, 2004 and 2003. The decrease in 2005 was due to the equipment failure discussed earlier that temporarily reduced the output of the plant by approximately 30 percent. This equipment failure is expected to be repaired in the first quarter of 2006.

Manaus and Rio Negro. At our Manaus and Rio Negro facilities we began negotiating new power contracts in 2003, which were to expire in 2005 and 2006. These negotiations were negatively impacted by changes in the Brazilian political environment, and as a result, we recorded an impairment on these investments in 2004. As a result of new contracts entered into during the first quarter of 2005, we deconsolidated these plants and now account for them as equity investments. The new contracts also resulted in a decrease in earnings from these projects. The Manaus and Rio Negro plants had earnings from plant operations of $19 million in 2005, $30 million in 2004 and $12 million in 2003.

South American Pipelines. The EBIT for our Brazilian operations includes EBIT earned by our Bolivia to Brazil and Argentina to Chile pipelines. EBIT was $26 million in 2005, $28 million in 2004 and $18 million in 2003. EBIT increased from 2003 to 2004 due primarily to the Bolivia to Brazil pipeline reaching full operational capacity in the third quarter of 2003.

Other International Power

During 2005 and 2004, we recorded substantial gains and losses in our other international power operations primarily based on the sale of, or the decision to sell our Asian and Central American assets. These assets have been written down to the value expected to be realized upon the close of the sales. As of December 31, 2005, the total financial exposure on our investments in Asia and Central America was approximately $377 million. Until these sales close, which we expect in the first half of 2006, we have potential risk for negative impacts of operational, economic or political events that may occur.

Prior to the decision to sell these assets, our earnings in these areas were relatively stable as the underlying plants maintained steady levels of availability and production. However, our earnings from our Asian power assets decreased in 2005 as we did not recognize approximately $30 million of earnings in Asia because we did not believe these amounts could be realized.

Domestic Power

From 2003 to 2005, we sold substantially all of our domestic power assets, including all of our remaining restructured power contracts. In conjunction with these sales, we recorded significant impairments in our domestic power business and had substantially lower earnings in our domestic power plant operations during this three year period. The discussion that follows outlines the significant events that affected our domestic operating results during the period from 2003 to 2005.

- *MCV.* As of December 31, 2005, we maintain an equity ownership in a natural gas-fired power plant, MCV. Although the price of electricity sold by MCV is indexed to coal, the plant is fueled by natural gas, which it purchases under both long-term contracts and on the spot market. Due to significant increases in natural gas prices, the economic performance of the facility was greatly impacted. In 2004, we impaired our investment in MCV by $161 million based on a decline in the value of the investment due to the increase in fuel costs. In 2005, we recorded our proportionate share of losses on MCV based on MCV's impairment of the plant assets. These impairments and recorded losses reduced our net investment in the plant to zero at December 31, 2005. MCV's owners are pursuing various commercial alternatives, which could result in the recovery of some of our previously impaired investment.

- *Other Impairments and EBIT from Operations.* Prior to 2003, Chaparral Investors, L.L.C. owned interests in a number of domestic power facilities and was the principal equity investment through which we conducted our domestic power activities. We consolidated Chaparral and its related power plants in early 2003. In 2003 and 2004, among other impairments noted in the table above, we recorded substantial impairments, net of gains and losses based on the anticipated sale of our merchant and contracted plants, as well as operational and contractual issues at several of these facilities. Included in these amounts was a $25 million loss in 2004 on the termination of a power contract with our Marketing and Trading segment related to one of the assets sold, which was eliminated in consolidation. As these facilities were sold through 2004, we experienced lower EBIT in each year from the operation of these facilities. See Part II, Item 8, Financial Statements and Supplementary Data, Notes 2, 3, and 21 for a further discussion of these matters.

Field Services Segment

As of December 31, 2005, the remaining assets in our Field Services segment are our Bluebell and Altamont facilities located in the Rocky Mountain area. Effective January 1, 2006, these assets have been transferred to our Exploration and Production segment, as they primarily support our producing activities in that segment.

Prior to their sales from 2003 through the third quarter of 2005, our general and limited partner interests in GulfTerra and Enterprise and gathering and processing assets in south Texas and south Louisiana were the primary sources of earnings in our Field Services segment. The sales of these assets are further described in Part II, Item 8, Financial Statements and Supplementary Data, Note 21. Our south Louisiana operations are reported as discontinued operations for the three years ended December 31, 2005. The tables below and discussion that follows provide the operating results and additional analysis of significant factors affecting EBIT for our Field Services segment for each of the three years ended December 31:

	2005	2004	2003
		(In millions)	
Gathering and processing gross margins[1]	$ 25	$ 93	$ 96
Operating expenses			
Loss on long-lived assets	(10)	(507)	(173)
Other operating expenses	(31)	(87)	(120)
Operating loss	(16)	(501)	(197)
Earnings from unconsolidated affiliates	301	618	329
Other expense	—	(33)	(3)
EBIT	$285	$ 84	$ 129

[1] Gross margins consist of operating revenues less cost of products sold. We believe that this measurement is more meaningful for understanding and analyzing our Field Services segment's operating results because commodity costs historically were a significant factor in the determination of profit from our midstream activities.

	2005	2004	2003
		(In millions)	
Gathering and Processing Activities			
Gathering and processing margins	$ 25	$ 93	$ 96
Operating expenses	(8)	(87)	(120)
Other income (expense)	7	11	(7)
EBIT	24	17	(31)
GulfTerra/Enterprise-related Items			
Assets sold to GulfTerra	5	9	(7)
Assets/interests sold to Enterprise			
Sale of GP/LP interests	183	507	266
Sale of south Texas	—	(11)	(167)
Goodwill impairment	—	(480)	—
Other	(1)	(45)	—
Equity earnings	—	100	153
EBIT	187	80	245
Other Asset Sales			
Sale of Javelina investment	111	—	—
Dauphin Island/Mobile Bay	—	—	(86)
Termination of Needle Mountain gas supply contract	(28)	—	—
Other	(9)	(13)	1
	74	(13)	(85)
EBIT	$285	$ 84	$ 129

Gathering and Processing Activities. During the three years ended December 31, 2005, the decreases in our gross margins and in operation and maintenance expenses were primarily a result of asset sales, including the sales of our south Texas, north and south Louisiana, mid-continent and Indian Springs gathering and processing plants.

GulfTerra/Enterprise Related Items. During 2002 and 2003, we sold a number of assets to GulfTerra. While these sales decreased our gross margin and operating expenses, they increased the equity earnings from our general and limited partner interests in GulfTerra. However, over time, our equity earnings in GulfTerra declined as we sold our interests in that investment. The effect of significant transactions related to GulfTerra during 2005, 2004 and 2003 were as follows:

- Gain of $266 million on the sale of 50 percent of our interest in GulfTerra to Enterprise in 2003. At the same time, we recorded an impairment of our south Texas assets of $167 million based on the planned sale of these assets to Enterprise;
- Gain of $507 million upon the sale of our remaining 50 percent interest in the general partner of GulfTerra to Enterprise in 2004. As a result of this sale, we also impaired goodwill recorded on the segment; and
- Gain of $183 million on the sale of our remaining general partner and limited partner interests in Enterprise in 2005.

Corporate and Other Expenses, Net

Our corporate activities include our general and administrative functions as well as a number of miscellaneous businesses, which do not qualify as operating segments and are not material to our current year results. The following is a summary of significant items impacting the EBIT in our corporate operations for each of the three years ended December 31:

	2005	2004	2003
		(In millions)	
Change in litigation, insurance and other reserves	$(418)	$ (81)	$ (10)
Western Energy Settlement	(72)	(38)	(2)
Impairments, contract terminations and gains (losses) on asset sales:			
Telecommunications business	5	—	(396)
LNG business	—	—	(108)
Aircraft	—	8	(8)
Other operating earnings (losses) from other businesses	21	32	(22)
Restructuring charges	(27)	(91)	(91)
Debt gains (losses):			
Foreign currency fluctuations on Euro-denominated debt	36	(26)	(112)
Early extinguishment/exchange of debt	(29)	(18)	(49)
Other	(37)	(3)	(54)
Total EBIT	$(521)	$(217)	$(852)

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. In all of our legal and insurance matters, we evaluate each lawsuit and claim as to its merits and our defenses. Adverse rulings or unfavorable settlements against us related to these matters have impacted and may further impact our future results. In 2005 and 2004, we recorded significant charges in operation and maintenance expense to increase our litigation, insurance and other reserves based on ongoing assessments, developments and evaluations of the possible outcomes of these matters. In 2005, the most significant item was a charge in connection with a ruling by an appellate court that we indemnify a former subsidiary for certain payments being made under a retiree benefit plan. Additionally, we incurred charges in 2005 with the final prepayment of the Western Energy Settlement and charges related to increased premiums from a mutual insurance company in which we participate, based primarily on the impact of several hurricanes in 2004 and 2005. In 2004, we also incurred charges associated with the Western Energy Settlement obligation and charges related to our decision to withdraw from another mutual insurance company in which we were a member.

As discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 4, we accrued $80 million in 2004 related to the consolidation of our Houston-based operations. Our relocation costs were based on a discounted liability, which included estimates of future sublease rentals. During 2005, we recorded additional charges of $27 million related to vacating the remaining leased space and signing a termination agreement on the lease.

Interest and Debt Expense

The table below and discussion that follows provide an analysis of our interest and debt expense for each of the three years ended December 31:

	2005	2004	2003
		(In millions)	
Long-term debt, including current maturities	$1,348	$1,533	$1,696
Other interest	32	74	94
Total interest and debt expense	$1,380	$1,607	$1,790

Our total interest and debt expense decreased between 2003 and 2005 primarily due to the retirements of debt and other financing obligations, net of issuances. During 2005, our overall debt level declined by approximately $1.0 billion through a combination of repayments and asset sales, net of issuances. In 2004, our overall debt levels declined by $2.5 billion. See Part II, Item 8. Financial Statements and Supplementary Data, Note 14, for a further discussion of our activities related to debt repayments and issuances.

Distributions on Preferred Interests of Consolidated Subsidiaries

Our distributions on preferred securities decreased significantly between 2003 and 2005 due to the redemption, or reclassification as debt, of substantially all of these securities during these periods. For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Part II, Item 8, Financial Statements and Supplementary Data, Notes 14 and 15.

Income Taxes

Income taxes for the years ended December 31, 2005, 2004 and 2003 were ($289) million, $14 million and ($484) million, resulting in effective tax rates of 29 percent, (2) percent and 44 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- earnings from unconsolidated affiliates where we anticipate receiving dividends;
- foreign income taxed at different rates;
- sales and write offs of foreign investments;
- valuation allowances;
- audit settlements;
- non-deductible goodwill impairments; and
- non-taxable medicare reimbursements.

In 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to sales of our GulfTerra investment and impairments of certain of our foreign investments. The sale of GulfTerra resulted in a significant net taxable gain (compared to a lower book gain) and thus significant tax expense due to the non-deductibility of goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense in 2004 by approximately $139 million. Additionally, we received no U.S. federal income tax benefit on the impairment of certain of our foreign investments. The combination of these items resulted in an overall tax expense in a period for which there was a pre-tax loss. The effective tax rate for 2004 absent these items would have been 35 percent.

We have pending IRS and other taxing authority audits and income tax contingencies that are in various stages of completion. We have recorded a liability on these matters based on our best estimate of the ultimate outcome of each matter. As these audits are finalized and as these contingencies are resolved, we adjust our estimates, the impact of which could have a material effect on the recorded amount of income taxes and our effective tax rates in future periods. We had several such adjustments in 2005 which impacted our effective tax rate.

For a reconciliation of the statutory rate to our effective tax rate, valuation allowances and additional discussion of other income tax matters affecting us, see Part II, Item 8, Financial Statements and Supplementary Data, Note 7.

Discontinued Operations

We present our gathering and processing operations in south Louisiana, certain international power operations, petroleum markets operations and international natural gas and oil production operations outside of Brazil as discontinued operations in our financial statements. For the year ended December 31, 2005, income from our discontinued operations was $100 million compared to losses of $118 million and $1.3 billion in 2004 and 2003. Our 2005 income was primarily a result of the sale of our south Louisiana operations in the fourth quarter of 2005, partially offset by impairments of our discontinued international power operations in 2005. The gain on the sale of south Louisiana and the impairments of our international power assets are further discussed in Part II, Item, 8, Financial Statements and Supplementary Data, Note 3. Our 2004 losses related primarily to charges and losses on the sales of discontinued assets along with other operational and severance costs. The losses in 2003 related primarily to impairment charges on our discontinued petroleum refineries and on chemical assets and ceiling test charges related to our discontinued Canadian production operations.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Part II, Item 8, Financial Statements and Supplementary Data, Note 16, incorporated herein by reference.

Critical Accounting Policies

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

Price Risk Management Activities. We record the derivative instruments used in our price risk management activities at their fair values on our balance sheet. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary assumptions used to estimate the fair value of derivative instruments is pricing. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from immediate selected potential changes in quoted market prices:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(In millions)			
Derivatives designated as hedges	$ (653)	$ (751)	$ (98)	$ (555)	$ 98
Other commodity-based derivatives	(763)	(903)	(140)	(626)	137
Total	$(1,416)	$(1,654)	$(238)	$(1,181)	$235

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to time value, anticipated market liquidity and credit risk of our counterparties. The assumptions and methodologies we use to determine the fair values of our derivatives may differ from those used by our derivative counterparties. These differences can be significant and could impact our future operating results as we settle these positions.

Accounting for Natural Gas and Oil Producing Activities. Natural gas and oil reserves estimates underlie a number of the accounting estimates in our financial statements. The process of estimating natural gas and oil reserves, particularly proved undeveloped and proved non-producing reserves, is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. Accordingly, our reserve estimates are developed internally by a reserve reporting group separate from our operations group and reviewed by internal committees and internal auditors. In addition, a third-party engineering firm, which is appointed by and reports to the Audit Committee of our Board of Directors, prepares an independent estimate of a significant portion of our proved reserves. As of December 31, 2005, of our total proved reserves, 31 percent were undeveloped and 12 percent were developed, but non-producing. In addition, the data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates.

The estimates of proved natural gas and oil reserves primarily impact our property, plant and equipment amounts in our balance sheets and the depreciation, depletion and amortization amounts in our income statements, among other items. We use the full cost method to account for our natural gas and oil producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves in full cost pools maintained by geographic areas, regardless of whether reserves are actually discovered. We record depletion expense of these capitalized amounts over the life of our proved reserves based on the unit of production method and, if all other factors are held constant, a 10 percent increase in estimated proved reserves would decrease our unit of production depletion rate by 9 percent and a 10 percent decrease in estimated proved reserves would increase our unit of depletion rate by 11 percent.

Under the full cost accounting method, we are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This impairment test is referred to as a ceiling test. Our total capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues from proved reserves using end of period spot prices and, 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. Our ceiling test calculations include the effect of derivative instruments we have designated as, and that qualify as hedges of our anticipated natural gas and oil production. As a result, higher proved reserves can reduce the likelihood of ceiling test impairments. We recorded ceiling test charges in our continuing and discontinued operations of less than $1 million, $35 million and $76 million during 2005, 2004 and 2003.

The ceiling test calculation assumes that the price in effect on the last day of the quarter is held constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. A decline in commodity prices can impact the results of our ceiling test and may result in writedowns. A decrease in commodity prices of 10 percent from the price levels at December 31, 2005 would not have resulted in a ceiling test charge in 2005.

Asset and Investment Impairments. The accounting rules on asset and investment impairments require us to continually monitor our businesses and the business environment to determine if an event has occurred indicating that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then assess the expected future cash flows against which to compare the carrying value of the asset group being evaluated, a process which also involves judgment. We ultimately arrive at the fair value of the asset, which is determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset). The assessment of project level cash flows requires us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors. Actual results can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our impairment estimates. We recorded impairments of our long-lived assets of $406 million, $1.1 billion and $791 million and impairments on our investments in unconsolidated affiliates of $347 million, $397 million, and $449 million during the years ended December 31, 2005, 2004 and 2003. We also recorded asset and investment impairments of our discontinued operations of $169 million, $40 million and $1.5 billion, net of minority interest during the years ended December 31, 2005, 2004 and 2003. Future changes in the economic and business environment can impact our assessments of potential impairments.

Accounting for Legal and Environmental Reserves. We accrue legal and environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. Estimates of our liabilities are based on our evaluation of potential outcomes, currently available facts, and in the case of environmental reserves, existing technology and presently enacted laws and regulations taking into consideration the likely effects of societal and economic factors, estimates of associated onsite, offsite and groundwater technical studies and legal costs. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each matter.

As of December 31, 2005, we had accrued approximately $574 million for legal matters and $379 million for environmental matters. Our environmental estimates range from approximately $379 million to approximately $546 million, and the amounts we have accrued represent a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($75 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($304 million to $471 million) and the lower end of the expected range has been accrued.

Accounting for Pension and Other Postretirement Benefits. As of December 31, 2005, we had a $918 million pension asset and a $250 million liability for other postretirement benefits reflected in other assets and liabilities on our balance sheet related to our pension and other postretirement benefit plans. These amounts are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plans and other factors. A significant assumption we utilize is the discount rates used in calculating our benefit obligations. We select our discount rates by comparing the average expected timing of our pension and other postretirement obligations to the maturity profiles of the Moody's Corporate Bond Indices and the Citigroup Pension Discount Curve. Based on these comparisons, we select discount rates that appropriately reflect the yields included in these market sources adjusted for the estimated timing of our obligations.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are generally deferred and amortized into income over either the period of expected future service of active participants, or over the lives of the plan participants. The cumulative amount deferred as of December 31, 2005 is recorded as an $814 million increase in our pension asset and a $20 million reduction of our other postretirement liability. The following table shows the impact of a one percent change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2005 (in millions):

	Pension Benefits		Other Postretirement Benefits	
	Net Benefit Expense (Income)	Projected Benefit Obligation	Net Benefit Expense (Income)	Accumulated Postretirement Benefit Obligation
One percent increase in:				
Discount rates	$(14)	$(205)	$—	$(41)
Expected return on plan assets	(21)	—	(2)	—
Rate of compensation increase	1	6	—	—
Health care cost trends	—	—	1	20
One percent decrease in:				
Discount rates	$ 15	$ 245	$—	$ 44
Expected return on plan assets[1]	21	—	2	—
Rate of compensation increase	(1)	(5)	—	—
Health care cost trends	—	—	(1)	(18)

[1] If the actual return on plan assets was one percent lower than the expected return on plan assets, our expected cash contributions to our pension and other postretirement benefit plans would not significantly change.

Our estimates for our net benefit expense (income) are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred and recognized over three years. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit expense would have been $19 million lower for the year ended December 31, 2005.

We have not recorded an additional pension liability for our primary pension plan because the fair value of assets of that plan exceeded the accumulated benefit obligation of that plan by approximately $212 million and $226 million as of September 30, 2005 and December 31, 2005. If the accumulated benefit obligation exceeded plan assets under this primary pension plan as of September 30, 2005, we would have recorded a pre-tax additional pension liability of approximately $918 million, plus an amount equal to the excess of the accumulated benefit obligation over the assets of that plan. We would have also recorded an amount equal to this additional pension liability in accumulated other comprehensive loss, net of taxes, on our balance sheet.

As stated in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, we were ordered to indemnify a third party for certain benefit payments being made to a closed group of retirees pending the outcome of litigation related to these payments. We estimated the liability associated with this indemnification obligation using actuarial methods similar to those used in estimating our obligations on our other postretirement benefit plans, which involves using various assumptions, including those related to discount rates and health care trends. A one percent change in the discount rate assumption used in the calculation would have changed the liability (and the related expense) by approximately $45 million and a one percent change in the health care cost trend assumption would have changed the liability (and the related expense) by approximately $50 million as of and for the year ended December 31, 2005.

New Accounting Pronouncements Issued But Not Yet Adopted

See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 under *New Accounting Pronouncements Issued But Not Yet Adopted,* which is incorporated herein by reference.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

- Commodity Price Risk
  - Natural gas and oil price changes, impacting the forecasted sale of natural gas and oil in our Exploration and Production segment;
  - Locational price differences in natural gas changes, affecting our ability to optimize pipeline transportation capacity contracts held in our Marketing and Trading segment; and
  - Electricity and natural gas price changes and locational pricing changes, affecting the value of our natural gas contracts and remaining power contracts held in our Marketing and Trading and Power segments. During 2005, we assigned or entered into agreements to assign to third parties the majority of our power contract portfolio, including our Cordova tolling agreement. As a result, our sensitivity to change in power prices will be significantly reduced in future periods.
- Interest Rate Risk
  - Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed-rate debt;
  - Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions; and
  - Changes in interest rates used to discount liabilities which can result in higher or lower accretion expense over time.
- Foreign Currency Exchange Rate Risk
  - Weakening or strengthening of the U.S. dollar relative to the Euro can result in an increase or decrease in the value of our Euro-denominated debt obligations and the related interest costs associated with that debt; and
  - Changes in foreign currencies exchange rates where we have international investments may impact the value of those investments and the earnings and cash flows from those investments.

We manage these risks by entering into contractual commitments involving physical or financial settlement that attempt to limit exposure related to future market movements. Our risk management activities typically involve the use of the following types of contracts:

- Forward contracts, which commit us to purchase or sell energy commodities in the future;
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement at a specific price and future date;
- Options, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;
- Swaps, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and
- Structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we use in our risk management activities are derivative financial instruments. A discussion of our accounting policies for derivative instruments are included in Part II, Item 8, Financial Statements and Supplementary Data, Notes 1 and 10.

Commodity Price Risk

Marketing and Trading

Our Marketing and Trading segment attempts to mitigate its exposure to commodity price risk through the use of various financial instruments, including forwards, swaps, options and futures. We measure risks from our Marketing and Trading segment's commodity and energy-related contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to adverse market movements over a defined period of time within a specified confidence level and allows us to monitor our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio's sensitivity to its underlying risks. These analyses and our Value-at-Risk simulations do not include the commodity exposures of our Exploration and Production segment's sales of natural gas and oil production.

Our maximum expected one-day unfavorable impact on the fair values of our commodity and energy-related contracts as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $60 million and $16 million as of December 31, 2005 and 2004. Our highest, lowest and average of the month-end values for Value-at-Risk during 2005 was $60 million, $12 million and $36 million. Our Value-at-Risk increased significantly during 2005 due to several financial swaps and option contracts that we entered into during 2004 and 2005 to provide price protection on a portion of the Company's anticipated natural gas and oil production. These contracts increased our exposure to market changes in natural gas and oil prices, which were volatile during 2005. This volatility may continue into the future and actual losses in fair value may exceed those measured by Value-at-Risk.

Exploration and Production

Our Exploration and Production segment attempts to mitigate commodity price risk and to stabilize cash flows associated with its forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swap contracts. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of our natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(In millions)		
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2005	$(684)	$(786)	$(102)	$(582)	$102
December 31, 2004	$(557)	$(697)	$(140)	$(417)	$140

Interest Rate Risk

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

	December 31, 2005								December 31, 2004	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(In millions)									
Long-term debt and other obligations, including current portion — fixed rate	$1,062	$ 747	$ 643	$1,300	$1,536	$10,841	$16,129	$16,573	$17,747	$18,387
Average interest rate	4.9%	6.7%	6.9%	6.5%	8.5%	7.6%				
Long-term debt and other obligations, including current portion — variable rate	$ 149	$ 33	$ 33	$1,179	$ 515	$ 196	$ 2,105	$ 2,105	$ 1,442	$ 1,442
Average interest rate	9.5%	6.1%	6.1%	6.2%	6.1%	5.9%				

Foreign Currency Exchange Rate Risk

Debt

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2005, we have Euro-denominated debt with a principal amount of €522 million of which €22 million matures in 2006 and €500 million matures in 2009. As of December 31, 2005 and 2004, we had swaps that effectively converted €367 million and €725 million of debt into $418 million and $766 million. The remaining principal at December 31, 2005 and 2004 of €155 million and €325 million was subject to foreign currency exchange risk.

Power Contracts

Several of our international power plants in Asia, Central America and South America have long-term power sales contracts that are denominated in the local country's currencies. Because we expect to sell substantially all of our Asian and Central American power plants during the first half of 2006, our exposure to foreign currency exchange risk related to these power sales contracts will end when the related power plants are sold. We do not believe that the remaining exposure is material to our operations and have not chosen to mitigate this exposure.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, we used the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2005. Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of El Paso Corporation's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements and Financial Statement Schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries (the "Company") at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations,* on December 31, 2005, 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, FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51,* on January 1, 2004, Statement of Financial Accounting Standards (SFAS) No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity,* on July 1, 2003 and SFAS No. 143, *Accounting for Asset Retirement Obligations.*

Internal Control Over Financial Reporting

Also, in our opinion, management's assessment, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2006

EL PASO CORPORATION

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

	Year Ended December 31,		
	2005	2004	2003
Operating revenues			
Pipelines	$ 2,783	$2,651	$ 2,647
Exploration and Production	1,787	1,735	2,141
Marketing and Trading	(796)	(508)	(635)
Power	129	653	1,054
Field Services	123	1,097	1,283
Corporate and eliminations	(9)	(89)	(151)
	4,017	5,539	6,339
Operating expenses			
Cost of products and services	323	1,218	1,637
Operation and maintenance	2,083	1,744	1,999
Depreciation, depletion and amortization	1,121	1,068	1,157
Loss on long-lived assets	407	1,077	860
Taxes, other than income taxes	270	250	292
	4,204	5,357	5,945
Operating income (loss)	(187)	182	394
Earnings from unconsolidated affiliates	342	546	363
Other income	295	187	198
Other expenses	52	98	202
Interest and debt expense	1,380	1,607	1,790
Distributions on preferred interests of consolidated subsidiaries	9	25	52
Loss before income taxes	(991)	(815)	(1,089)
Income taxes	(289)	14	(484)
Loss from continuing operations	(702)	(829)	(605)
Discontinued operations, net of income taxes	100	(118)	(1,269)
Cumulative effect of accounting changes, net of income taxes	(4)	—	(9)
Net loss	(606)	(947)	(1,883)
Preferred stock dividends	27	—	—
Net loss available to common stockholders	$ (633)	$ (947)	$(1,883)
Basic and diluted loss per common share			
Loss from continuing operations	$ (1.13)	$(1.30)	$ (1.01)
Discontinued operations, net of income taxes	0.16	(0.18)	(2.12)
Cumulative effect of accounting changes, net of income taxes	(0.01)	—	(0.02)
Net loss per common share	$ (0.98)	$(1.48)	$ (3.15)
Basic and diluted average common shares outstanding	646	639	597

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,132	$ 2,117
Accounts and notes receivable		
Customer, net of allowance of $67 in 2005 and $198 in 2004	1,120	1,307
Affiliates	58	133
Other	141	187
Assets from price risk management activities	641	601
Margin and other deposits held by others	1,124	79
Assets held for sale and from discontinued operations	36	289
Deferred income taxes	396	418
Other	537	501
Total current assets	6,185	5,632
Property, plant and equipment, at cost		
Pipelines	19,965	19,418
Natural gas and oil properties, at full cost	15,738	14,968
Other	1,397	2,238
	37,100	36,624
Less accumulated depreciation, depletion and amortization	17,965	18,075
Total property, plant and equipment, net	19,135	18,549
Other assets		
Investments in unconsolidated affiliates	2,473	2,574
Assets from price risk management activities	1,368	1,584
Goodwill and other intangible assets, net	413	421
Other	2,264	2,623
	6,518	7,202
Total assets	$31,838	$31,383

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2005	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 864	$ 965
Affiliates	10	21
Other	730	474
Short-term financing obligations, including current maturities	1,211	955
Liabilities from price risk management activities	1,418	852
Liabilities related to discontinued operations	8	115
Margin deposits held by us	497	131
Accrued interest	295	333
Other	679	726
Total current liabilities	5,712	4,572
Long-term financing obligations, less current maturities	17,023	18,241
Other		
Liabilities from price risk management activities	2,005	1,026
Deferred income taxes	1,407	1,287
Other	2,271	2,452
	5,683	4,765
Commitments and contingencies		
Securities of subsidiaries		
Securities of consolidated subsidiaries	31	367
Stockholders' equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000, 4.99% convertible perpetual shares in 2005; stated at liquidation value	750	—
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 667,082,043 shares in 2005 and 651,064,508 shares in 2004	2,001	1,953
Additional paid-in capital	4,592	4,538
Accumulated deficit	(3,415)	(2,809)
Accumulated other comprehensive income (loss)	(332)	1
Treasury stock (at cost); 7,620,272 shares in 2005 and 7,767,088 shares in 2004	(190)	(225)
Unamortized compensation	(17)	(20)
Total stockholders' equity	3,389	3,438
Total liabilities and stockholders' equity	$31,838	$31,383

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2005	2004	2003
Cash flows from operating activities			
Net loss	$ (606)	$ (947)	$(1,883)
Less income (loss) from discontinued operations, net of income taxes	100	(118)	(1,269)
Net loss before discontinued operations	(706)	(829)	(614)
Adjustments to reconcile net loss to net cash from operating activities			
Depreciation, depletion and amortization	1,121	1,068	1,157
Deferred income tax benefit	(267)	(44)	(618)
Loss on long-lived assets	407	1,077	785
Earnings from unconsolidated affiliates, adjusted for cash distributions	(63)	(211)	(17)
Other non-cash income items	388	447	503
Asset and liability changes			
Accounts and notes receivable	94	492	2,548
Change in price risk management activities, net	325	191	85
Accounts payable	(103)	(322)	(2,142)
Broker and other margins on deposit with others	(1,045)	121	623
Broker and other margins on deposit with us	366	(24)	32
Western Energy Settlement liability	(395)	(626)	—
Other asset changes	232	14	(182)
Other liability changes	(102)	(298)	102
Cash provided by continuing activities	252	1,056	2,262
Cash provided by discontinued activities	16	260	67
Net cash provided by operating activities	268	1,316	2,329
Cash flows from investing activities			
Capital expenditures	(1,718)	(1,804)	(2,349)
Cash paid for acquisitions, net of cash acquired	(1,025)	(47)	(1,078)
Net proceeds from the sale of assets and investments	1,424	1,927	2,458
Net change in restricted cash	74	578	(534)
Net change in notes receivable from affiliates	11	120	(43)
Other	192	(1)	—
Cash provided by (used in) continuing activities	(1,042)	773	(1,546)
Cash provided by discontinued activities	541	1,130	357
Net cash provided by (used in) investing activities	(501)	1,903	(1,189)

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2005	2004	2003
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	1,620	1,300	3,633
Payments to retire long-term debt and other financing obligations	(1,668)	(2,306)	(2,824)
Net repayments under revolving and other short-term credit facilities	—	(850)	(650)
Net proceeds from issuance of notes payable	—	—	84
Repayment of notes payable	—	(214)	(8)
Net proceeds from issuance of preferred stock	723	—	—
Payments to minority interest and preferred interest holders	(306)	(35)	(1,277)
Issuances of common stock	—	73	120
Dividends paid	(121)	(101)	(203)
Contributions from discontinued operations	557	1,025	424
Other	—	(33)	(177)
Cash provided by (used in) continuing activities	805	(1,141)	(878)
Cash used in discontinued activities	(557)	(1,390)	(424)
Net cash provided by (used in) financing activities	248	(2,531)	(1,302)
Change in cash and cash equivalents	15	688	(162)
Cash and cash equivalents			
Beginning of period	2,117	1,429	1,591
End of period	$ 2,132	$ 2,117	$ 1,429
Supplemental Cash Flow Information Related to Continuing Operations			
Interest paid, net of amounts capitalized	$ 1,336	$ 1,536	$ 1,657
Income tax payments	22	67	22

See accompanying notes.

EL PASO CORPORATION

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

	For the Years Ended December 31,					
	2005		2004		2003	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred stock, $0.01 par value						
Balance at beginning of year	—	$ —	—	$ —	—	$ —
Equity offering	1	750	—	—	—	—
Balance at end of year	1	750	—	—	—	—
Common stock, $3.00 par value						
Balance at beginning of year	651	1,953	639	1,917	605	1,816
Exchange of equity security units	14	41	—	—	15	45
Western Energy Settlement equity offerings	—	—	9	26	18	53
Other, net	2	7	3	10	1	3
Balance at end of year	667	2,001	651	1,953	639	1,917
Additional paid-in capital:						
Balance at beginning of year		4,538		4,576		4,444
Compensation related issuances		(18)		15		8
Tax effects of equity plans		2		5		(26)
Exchange of equity security units		230		—		189
Western Energy Settlement equity offerings		—		46		67
Dividends		(131)		(104)		(96)
Other		(29)		—		(10)
Balance at end of year		4,592		4,538		4,576
Accumulated deficit:						
Balance at beginning of year		(2,809)		(1,862)		21
Net loss		(606)		(947)		(1,883)
Balance at end of year		(3,415)		(2,809)		(1,862)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		1		(40)		(235)
Other comprehensive income (loss)		(333)		41		195
Balance at end of year		(332)		1		(40)
Treasury stock, at cost:						
Balance at beginning of year	(8)	(225)	(7)	(222)	(6)	(201)
Compensation related issuances	1	47	—	9	—	—
Other	(1)	(12)	(1)	(12)	(1)	(21)
Balance at end of year	(8)	(190)	(8)	(225)	(7)	(222)
Unamortized compensation:						
Balance at beginning of year		(20)		(23)		(95)
Issuance of restricted stock		(22)		(28)		(1)
Amortization of restricted stock		18		23		60
Forfeitures of restricted stock		7		9		15
Other		—		(1)		(2)
Balance at end of year		(17)		(20)		(23)
Total stockholders' equity	659	$ 3,389	643	$ 3,438	632	$ 4,346

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2005	2004	2003
Net loss	$(606)	$ (947)	$(1,883)
Foreign currency translation adjustments (net of income tax of $4 in 2005, $(38) in 2004 and $51 in 2003)	(9)	11	108
Minimum pension liability accrual (net of income tax of $2 in 2005, $11 in 2004 and $7 in 2003)	(3)	(22)	11
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $229 in 2005, $8 in 2004 and $50 in 2003)	(415)	22	101
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $46 in 2005, $8 in 2004 and $11 in 2003)	79	30	(25)
Change in unrealized gains on available for sale securities (net of income tax of $9 in 2005)	15	—	—
Other comprehensive income (loss)	(333)	41	195
Comprehensive loss	$(939)	$ (906)	$(1,688)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our results for all periods presented reflect our south Louisiana gathering and processing assets, which were part of our Field Services segment, certain of our international power operations, our Canadian and certain other international natural gas and oil production operations, our petroleum markets operations and our coal mining operations 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 stockholders' equity.

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 if 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 policies and decisions 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. On January 1, 2004, we adopted the provisions of FASB Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* The adoption of this standard did not have a material impact to our financial statements. For a further discussion of our variable interests, see Note 21.

Use of Estimates

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

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, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Of our regulated pipelines, all but ANR 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 discontinued the application of SFAS No. 71 in 1996, primarily due to the level of competition and discounting in ANR's market areas, uncertainties related to expired contracts and the construction of competing facilities. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Items that are generally recorded differently as a result of applying regulatory accounting requirements include postretirement employee benefit plan costs, an equity return component on regulated capital projects and certain costs included in, or expected to be included in, future rates.

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

Cash and Cash Equivalents

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

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets on our balance sheet based on when we expect this cash to be used. As of December 31, 2005, we had $281 million of restricted cash in current assets and $168 million in other non-current assets. As of December 31, 2004, we had $180 million of restricted cash in current assets and $180 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.

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' property, plant and equipment. 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]	1-63
Non-SFAS No. 71	Composite[1]	1-66
Non-regulated systems		
Transmission and storage facilities	Straight-line	5-34
Power facilities	Straight-line	27
Gathering and processing systems	Straight-line	3-35
Buildings and improvements	Straight-line	9-25
Office and miscellaneous equipment	Straight-line	1-15

(1) Under the composite (group) 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 operating income.

We capitalize a carrying cost on funds related to 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 of our regulated transmission businesses and unevaluated costs related to our natural gas and oil properties, 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, 2005, 2004 and 2003, were $45 million,

$39 million and $31 million. These amounts are included as a reduction of interest expense in our income statements. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized during the years ended December 31, 2005, 2004 and 2003 were $31 million, $22 million and $19 million. 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 evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values 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) our long-lived assets' ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investments in unconsolidated affiliates. If an impairment is indicated or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values 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 being 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 significant 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. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and periodically assessed in our ceiling test calculations as discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs on a quarterly basis. Specifically, we transfer costs to the amortizable base when properties are determined to have proved reserves. In addition, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory dry holes are determined to be unsuccessful. Additionally, the amortizable base includes future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values; and geological and geophysical costs incurred that cannot be associated with specific unevaluated properties or prospects in which we own a direct interest.

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 the ceiling is not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to the ceiling. 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. Our ceiling test calculations exclude the estimated future cash outflows associated with asset retirement liabilities related to proved developed reserves.

When we sell or convey interests in our natural gas and oil properties, we reduce our natural gas and oil 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. Goodwill is not amortized, but instead is 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 amounts of our goodwill as of December 31, 2005 and 2004 and the changes in the net carrying amounts of goodwill for the years ended December 31, 2005 and 2004 by segment are as follows:

	Pipelines	Field Services	Power	Total
		(In millions)		
Goodwill as of January 1, 2004	$413	$480	$ 3	$ 896
Impairments of goodwill in 2004	—	(480)	—	(480)
Other changes in 2004	—	—	(3)	(3)
Goodwill as of December 31, 2004 and 2005	$413	$ —	$—	$ 413

The goodwill impairment in our Field Services segment resulted from the sales of our GulfTerra investment and certain segment assets. As a result of these sales, we determined that the remaining segment assets could not support the segment's goodwill.

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense 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 returns on plan assets and amortization of certain deferred gains and losses. For a further discussion of our policies with respect to our pension and postretirement plans, See Note 17.

In our balance sheet, changes in the recorded assets and liabilities associated with our primary pension plan and other postretirement benefit plans are based on the amounts of our contributions, benefit expense and changes in deferred gains and losses during a given period. Changes in the liabilities on our other pension plans are reported as changes in other comprehensive income, net of income taxes, on our financial statements. For a further discussion of the contributions, benefits and deferred gains and losses related to our pension and other postretirement obligations see Note 17.

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 $49 million, which is accounted for as an actuarial gain in our postretirement benefit liabilities as of December 31, 2005 and 2004. The adoption of this guidance reduced our postretirement benefit expense by approximately $6 million in 2005.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. The revenue recognition policies of our most significant operating segments are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. Gas not needed for operations is based on the volumes we are allowed to retain relative to the amounts of gas we use for operating purposes. We recognize revenue from gas not used in operations when we retain the volumes under our tariffs. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. We are subject to FERC regulations and, as a result, revenues we collect in rate proceedings may be subject to refund. We establish reserves for these potential refunds.

Exploration and Production revenues. Our Exploration and 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 production are included in cost of sales.

Power and Marketing and Trading revenues. Our Power and Marketing and Trading segments derive revenues from physical sales of natural gas and power and the management of their 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 contractual or market price.

Environmental Costs and Other Contingencies

Environmental Costs. We record liabilities at their undiscounted amounts on our balance sheet in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of 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. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

We evaluate separately from our liability any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties including insurance coverage. When recovery is assured after an evaluation of their creditworthiness or solvency, we record and report an asset separately from the associated liability on our balance sheet.

Other Contingencies. 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 the associated 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 consist of the following activities:

- derivatives entered into to hedge or otherwise reduce the commodity, interest rate and foreign currency exposure on our natural gas and oil production and our long-term debt;
- derivatives related to our historical power contract restructuring business; and
- derivatives related to trading activities that we historically entered into with the objective of generating profits from exposure to shifts or changes in market prices.

Our derivatives are reflected on 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 10 for a further discussion of our price risk management activities.

Derivatives that we have designated as accounting hedges impact our revenues or expenses based on the nature and timing of the transactions that they hedge. Derivatives related to our power contract restructuring activities are marked-to-market and reflected as either revenues (for changes in the fair values of the power sales contracts) or expenses (for changes in the fair values of the power supply agreements). We report the changes in the fair value of our other derivative contracts in revenue.

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows (other than those derivatives intended to hedge the principal amounts of our foreign currency denominated debt). In our balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables.

Income Taxes

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

Foreign Currency Translation

For foreign operations whose functional currency is the local currency, assets and liabilities are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. The cumulative translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholders' equity.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires that we record a liability for retirement and removal costs of long-lived assets used in our business when the timing and/or amount of the settlement of those costs are relatively certain. On December 31, 2005, we adopted the provisions of FIN No. 47, *Accounting for Conditional Asset Retirement Obligations*, which requires that we record a liability for those retirement and removal costs in which the timing and/or amount of the settlement of the costs are uncertain.

We have legal obligations associated with our natural gas and oil wells and related infrastructure, our natural gas pipelines and related transmission facilities and storage wells, as well as in our corporate headquarters building. We have obligations to plug wells when production on those wells is exhausted or we no longer plan to use them, and when we abandon them. Our legal obligations associated with our natural gas transmission facilities relate primarily to purging and sealing the pipelines if they are abandoned. We also have obligations to remove hazardous materials associated with our natural gas transmission facilities and in our corporate headquarters if these facilities are replaced or renovated. We accrue a liability on those legal obligations when we can estimate the timing and amount of their settlement. These obligations include those where we have plans to or otherwise will be legally required to replace, remove or retire the associated assets. Substantially all of our natural gas pipelines can be maintained indefinitely and, as a result, we have not accrued a liability associated with purging and sealing them.

Our asset retirement liabilities are recorded at their estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. Many of our regulated pipelines have the ability to file for recovery of certain of these costs from their customers and have recorded an asset (rather than expense) associated with the depreciation of the property, plant and equipment and accretion of the liabilities described above. We recorded a charge as a cumulative effect of accounting change, net of income taxes of $4 million in 2003 and $2 million in 2005, of approximately $9 million in the first quarter of 2003 and $4 million in the fourth quarter of 2005 related to our adoption of SFAS No. 143 (primarily related to our Exploration and Production segment), and FIN No. 47 (primarily related to our Pipelines segment and our corporate activities), respectively.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates ranging from six to eight percent, a projected inflation rate of 2.5 percent and the estimated timing and amount of settling our obligations, which are based on internal models and external quotes. The net asset retirement liability as of December 31 reported on our balance sheet in other current and non-current liabilities, and the changes in the net liability for the years ended December 31, were as follows:

	2005	2004
	(In millions)	
Net asset retirement liability at January 1	$322	$269
Liabilities settled[1]	(93)	(38)
Accretion expense	28	25
Liabilities incurred	19	36
Changes in estimate	(16)	30
Adoption of FIN No. 47	15	—
Net asset retirement liability at December 31	$275	$322

[1] Increase is due primarily to the sale of certain domestic natural gas and oil properties in our Exploration and Production segment. For a further discussion of these divestitures see Note 3.

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. If we had adopted the provisions of FIN No. 47 as of January 1, 2004, our asset retirement liability would have been higher by approximately $13 million and $14 million as of January 1, 2004 and December 31, 2004, and our net income for the years ended December 31, 2004 and 2005 would not have been materially affected.

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

On July 1, 2003, we adopted the provisions of SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* and reclassified $625 million of our Capital Trust I and Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations on our balance sheet as required by that standard. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement.

Stock-Based Compensation

We account for our stock-based compensation plans using the intrinsic value method under the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. We grant stock awards under stock option plans, restricted stock plans, and employee stock purchase programs. Our stock options are granted under a fixed plan at the market value on the date of grant. Accordingly, no compensation expense is recognized. Had we accounted for our stock-based compensation using the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the net loss available to common stockholders and per share impacts on our financial statements would have been different. The following table shows the impact on net loss available to common stockholders and loss per share had we applied SFAS No. 123 (See Note 19 for the weighted average assumptions of our options granted in 2005, 2004 and 2003):

	Year Ended December 31,		
	2005	2004	2003
	(In millions, except per common share amounts)		
Net loss available to common stockholders, as reported	$ (633)	$ (947)	$(1,883)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	12	14	38
Deduct: Total stock-based compensation expense determined under fair-value based method for all awards, net of taxes(1)	(19)	(25)	(38)
Net loss available to common stockholders, pro forma	$ (640)	$ (958)	$(1,883)
Loss per share:			
Basic and diluted, as reported	$(0.98)	$(1.48)	$ (3.15)
Basic and diluted, pro forma	$(0.99)	$(1.50)	$ (3.15)

(1) Amounts have been adjusted from those previously reported to reflect the impact of actual forfeitures of unvested stock option awards on proforma compensation expense.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2005, 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 Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment.* This standard and related interpretations amend previous stock-based compensation guidance and require companies to measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in its financial statements over the requisite service period. The fair value of options is determined by a model (e.g. Black-Scholes or binomial) using a variety of assumptions, the most significant of which are expected price volatility and expected term of the option. We also make assumptions about expected forfeiture rates. Our assumptions for new awards upon adoption of this standard could differ from those we have historically utilized. We will adopt SFAS No. 123(R) and related interpretations on January 1, 2006 prospectively for awards of stock-based compensation granted after that date and for the unvested portion of outstanding awards at that date. Based on the stock-based compensation awards outstanding as of December 31, 2005 and our anticipated level of stock-based compensation awards in 2006, we expect to record incremental compensation expense of approximately $15 million to $20 million as a result of adopting this standard.

Accounting for Pipeline Integrity Costs. In June 2005, the FERC issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs requiring us to prospectively expense certain costs incurred after January 1, 2006, instead of our current practice of capitalizing them as part of our property, plant and equipment. In December 2005, FERC approved a request to allow one of our regulated pipeline subsidiaries, EPNG, to adopt the provisions of this release in December 2005, which did not have a material impact on our financial statements for the year ended December 31, 2005. We currently estimate that we will be required to expense an additional amount of pipeline integrity costs under this accounting release in the range of approximately $26 million to $41 million annually.

2. Acquisitions

Medicine Bow. In August 2005, we acquired Medicine Bow, a privately held energy company for total cash consideration of $853 million. Medicine Bow owns a 43.1 percent interest in Four Star, an unconsolidated affiliate. Our proportionate share of the future operating results associated with Four Star will be reflected as earnings from unconsolidated affiliates in our financial statements.

The Medicine Bow acquisition was accounted for using the purchase method of accounting. No goodwill was recorded associated with the acquisition. As part of our purchase price allocation, we allocated approximately $0.4 billion to property, plant, and equipment (of which $0.3 billion related to properties in our natural gas and oil full cost pool), $0.8 billion to our unconsolidated investment in Four Star, and $0.4 billion related to deferred tax liabilities. We reflected Medicine Bow's results of operations in our income statement beginning September 1, 2005. The following summary unaudited pro forma consolidated results of operations for the years ended December 31, 2005 and 2004 reflect the combination of our historical income statements with Medicine Bow, adjusted for certain effects of the acquisition and related funding. These pro forma results are prepared as if the acquisition had occurred as of the beginning of the periods presented and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

	Year Ended December 31,	
	2005[(1)]	2004
	(In millions, except per share amounts)	
Revenues	$4,056	$5,589
Net loss available to common stockholders	(623)	(958)
Basic and diluted loss per share	(0.96)	(1.50)

(1) Excludes a $13 million charge or loss of $(0.02) per share for change in control payments triggered at Medicine Bow as a result of the acquisition.

Chaparral and Gemstone. During 2003, we acquired the remaining third party interests in our Chaparral and Gemstone power generation investments for approximately $1 billion and began consolidating them in the first and second quarters of 2003, respectively. We have reflected the results of operations in our income statement for Chaparral as though we acquired it on January 1, 2003 and the results of operations for Gemstone in our income statement since April 1, 2003. Had we acquired Gemstone on January 1, 2003, our net income and loss per share would have been unaffected.

3. Divestitures

Sales of Assets and Investments

During 2005, 2004 and 2003, we completed the sale of a number of assets and investments in each of our business segments and corporate operations. The following table summarizes the proceeds from these sales:

	2005	2004	2003
		(In millions)	
Pipelines	$ 49	$ 59	$ 145
Exploration and Production	7	24	673
Power	625	884	768
Field Services	657	1,029	753
Corporate	121	16	149
Total continuing[(1)]	1,459	2,012	2,488
Discontinued	577	1,295	808
Total	$2,036	$3,307	$3,296

[(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 $35 million, $85 million and $30 million for the years ended December 31, 2005, 2004 and 2003.

The following table summarizes the significant assets sold. See Notes 5 and 21 for a discussion of gains, losses and impairments related to the sales below:

	2005	2004	2003
Pipelines	• Facilities located in the southeastern U.S. • Interest in a gathering system in the western U.S.	• Australian pipelines • Interest in gathering systems	• 2.1% interest in Alliance pipeline • Equity interest in Portland Natural Gas Transmission System • Horsham pipeline in Australia
Exploration and Production	• Miscellaneous domestic natural gas and oil properties	• Brazilian exploration and production acreage	• Natural gas and oil properties in NM, TX, LA, OK and the Gulf of Mexico
Power	• Cedar Brakes I and II • Interest in power plants in Korea, India, England and China • Four domestic power plants • Portion of investment in Intercontinental Exchange • Mohawk River Funding II • Power turbines	• Utility Contract Funding • 31 domestic power plants and several turbines	• Interest in CE Generation L.L.C. • Mt. Carmel power plant • CAPSA/CAPEX investments • East Coast Power
Field Services	• General partner and common unit interests in Enterprise • Interest in Indian Springs natural gas gathering system and processing facility • Interest in Javelina natural gas processing and pipeline assets	• Remaining general partnership interest, common units and Series C units in GulfTerra • South TX processing plants • Dauphin Island and Mobile Bay investments	• Gathering systems located in WY • Midstream assets in the north LA and Mid-Continent regions • Common, Series B preference units and 50 percent general partnership interests in GulfTerra
Corporate	• Lakeside Technology Center	• Aircraft	• Aircraft • Enerplus Global Energy Management Company and its financial operations • EnCap funds management business and its investments
Discontinued	• Interest in Paraxylene facility • MTBE processing facility • International natural gas and oil properties • South Louisiana gathering and processing assets • Ammonia manufacturing facility	• Natural gas and oil 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

We have also completed or entered into agreements to sell (i) our interests in our remaining Asian power assets (which includes our CEBU and East Asia Utilities power plants in discontinued operations) for $174 million; (ii) substantially all of our interests in our Central and other South American power assets (which includes our Nejapa power plant in discontinued operations) for $164 million; (iii) our interest in a power facility in Hungary for $28 million; and (iv) a power turbine for $9 million. In February 2006, we entered into a memorandum of understanding to settle our ongoing contractual disputes with Petrobras relating to the Macae power facility and to sell our interest in the facility to Petrobras for $358 million. We also signed a letter of intent in February 2006 to resolve the arbitration proceedings with COPEL relating to the Araucaria power facility and to sell our interest in the facility to COPEL for $190 million. See Note 16 for a further discussion of these matters.

Discontinued Operations

South Louisiana Gathering and Processing Operations. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. In the fourth quarter of 2005, we completed the sale of these assets for net proceeds of approximately $486 million and recorded a pre-tax gain of approximately $394 million.

International Power Operations. During 2005, our Board of Directors approved the sale of our Asian and Central American power asset portfolio, which included our consolidated interests in the Nejapa, CEBU and East Asia Utilities power plants. During 2005, we recognized approximately $166 million of impairment losses, net of minority interest, based on our decision to sell these assets. We expect to complete the sale of our Nejapa, CEBU and East Asia Utilities power plants during 2006.

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, 2005, we have completed the sale of substantially all of these properties for total proceeds of approximately $395 million. During 2005 and 2004, we recognized approximately $5 million and $22 million in losses based on our decision to sell these assets.

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 certain of 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 $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.

Coal Mining. In 2003, we sold our coal mining operations, which consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. We received sales proceeds of $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.

As of December 31, 2005 and 2004, our assets held for sale (which primarily relate to a natural gas gathering system and processing facility we sold in 2005) and the assets of our discontinued operations were $36 million and $587 million and our total liabilities were $8 million and $170 million primarily related to property, plant and equipment and working capital balances related to these facilities. The summarized operating results of our discontinued operations were as follows:

	South Louisiana Gathering and Processing Operations	International Power Operations	International Natural Gas and Oil Production Operations	Petroleum Markets	Coal Mining	Total
			(In millions)			
Year Ended December 31, 2005						
Revenues	$ 292	$ 160	$ 2	$ 125	$ —	$ 579
Costs and expenses	(264)	(136)	(1)	(181)	—	(582)
Gain (loss) on long-lived assets	394	(177)	(5)	7	—	219
Other income	—	9	—	12	—	21
Income (loss) before income taxes	$ 422	$(144)	$ (4)	$ (37)	$ —	237
Income taxes						137
Income from discontinued operations, net of income taxes						$ 100

	South Louisiana Gathering and Processing Operations	International Power Operations	International Natural Gas and Oil Production Operations	Petroleum Markets	Coal Mining	Total
			(In millions)			
Year Ended December 31, 2004						
Revenues	$ 265	$ 142	$ 31	$ 787	$ —	$ 1,225
Costs and expenses	(229)	(140)	(53)	(839)	—	(1,261)
Loss on long-lived assets	—	(30)	(22)	(36)	—	(88)
Other income	—	5	—	15	—	20
Interest and debt expense	—	—	1	(3)	—	(2)
Income (loss) before income taxes	$ 36	$ (23)	$ (43)	$ (76)	$ —	(106)
Income taxes						12
Loss from discontinued operations, net of income taxes						$ (118)
Year Ended December 31, 2003						
Revenues	$ 246	$ 122	$ 88	$ 5,652	$ 27	$ 6,135
Costs and expenses	(242)	(115)	(129)	(5,793)	(13)	(6,292)
Loss on long-lived assets	—	—	(89)	(1,404)	(9)	(1,502)
Other income (expense)	—	5	—	(10)	1	(4)
Interest and debt expense	—	(1)	4	(11)	—	(8)
Income (loss) before income taxes	$ 4	$ 11	$(126)	$(1,566)	$ 6	(1,671)
Income taxes						(402)
Loss from discontinued operations, net of income taxes						$(1,269)

4. Restructuring and Other Charges

The discussion below provides additional details of certain costs incurred in connection with our ongoing liquidity enhancement and cost reduction efforts in 2003, 2004, and 2005 and in conjunction with our Western Energy Settlement. These charges were recorded as part of operations and maintenance expense.

Employee severance, retention and transition costs. Employee severance costs were not significant in 2005. During 2004, we eliminated approximately 1,900 full-time positions from our continuing businesses and approximately 1,200 positions related to businesses we discontinued. As a result, we incurred approximately $38 million of employee severance costs primarily related to our Exploration and Production segment and corporate operations. Additionally, during 2003, we eliminated approximately 900 full-time positions from our continuing businesses and approximately 1,800 positions related to businesses we discontinued and incurred approximately $76 million of employee severance costs, primarily related to our Marketing and Trading segment and corporate operations. As of December 31, 2005, substantially all of the total employee severance, retention and transition costs had been paid.

Office relocation and consolidation. During 2004, we announced that we would consolidate our Houston-based operations into one location and incurred $80 million of charges to record the discounted liability, net of estimated sub-lease rentals, for our obligations under leases for space we no longer use. In 2005, we vacated our remaining leased space, signed a termination agreement on the lease and recorded additional charges of $27 million related to these actions. The costs associated with this office relocation and consolidation have been charged to corporate operations. Actual moving expenses related to the relocation were insignificant and were expensed in the periods that they were incurred. As of December 31, 2005, our remaining liability associated with this consolidation and relocation was $97 million.

Western Energy Settlement. During 2003 and 2005, we incurred charges in operations and maintenance expense related to the final resolution of our Western Energy Settlement of $104 million and $59 million. Final payments under this settlement were made in early 2005.

Other. In 2003, our contract termination and other costs included charges of approximately $44 million related to amounts paid for canceling or restructuring our obligations to transport LNG from supply areas to domestic and international market centers and were charged to corporate operations.

5. (Gain) Loss on Long-Lived Assets

Our (gain) loss 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 (gain) loss on long-lived assets was as follows:

	2005	2004	2003
		(In millions)	
Net realized (gain) loss	$ 1	$ (16)	$ 69
Asset impairments			
Power			
Brazilian assets[1]	333	183	—
Domestic assets and restructured power contract entities[2]	—	397	147
Turbines[2]	18	1	33
Pipelines			
Pipeline development projects[3]	46	—	—
Field Services			
Goodwill impairment[4]	—	480	—
Indian Springs processing assets[2]	—	13	—
South Texas processing assets[2]	—	—	167
Other	9	10	4
Exploration and Production			
Other	—	8	10
Corporate			
Telecommunications assets[2]	—	—	396
Other	—	1	34
Total asset impairments	406	1,093	791
Loss on long-lived assets	407	1,077	860
(Gain) loss on sale of investments in unconsolidated affiliates, net of impairments[5]	(91)	(124)	176
Loss on assets and investments	$316	$ 953	$1,036

(1) These assets were impaired as a result of negotiations associated with the power contracts of these plants. See Note 16 for a further discussion of these matters.
(2) We adjusted the carrying value of these assets to their estimated fair value, less cost to sell.
(3) This impairment resulted from our decision to discontinue development of several pipeline expansion projects.
(4) This impairment resulted from the sale of substantially all of our interests in GulfTerra, as well as the sale of our processing assets in south Texas to affiliates of Enterprise in 2004 (see Note 21).
(5) See Note 21 for a further description of these gains and losses.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 3 and 21. For additional discussion on goodwill and other intangibles, see Note 1.

6. 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:

	2005	2004	2003
		(In millions)	
Other Income			
Interest income	$129	$ 93	$ 83
Allowance for funds used during construction	31	23	19
Development, management and administrative services fees on power projects from affiliates	13	15	12
Re-application of SFAS No. 71 (CIG and WIC)	—	—	18
Foreign currency gain	36	13	12
Gain on sale of cost basis investments	40	—	7
Dividend income	19	—	6
Other	27	43	41
Total	$295	$187	$198
Other Expenses			
Foreign currency losses	$ 1	$ 26	$112
Loss on early extinguishment of debt	29	12	37
Loss on exchange of equity security units	—	—	12
Minority interest in consolidated subsidiaries	4	40	3
Other	18	20	38
Total	$ 52	$ 98	$202

7. Income Taxes

Pretax Income (Loss) and Income Tax Expense (Benefit). The tables below show our pretax income (loss) from continuing operations and the components of income tax expense (benefit) for each of the years ended December 31:

	2005	2004	2003
		(In millions)	
Pretax Income (Loss)			
U.S.	$(640)	$(757)	$(1,334)
Foreign	(351)	(58)	245
	$(991)	$(815)	$(1,089)
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ (10)	$ (15)	$ 35
State	(35)	36	57
Foreign	23	37	42
	(22)	58	134
Deferred			
Federal	(297)	(68)	(568)
State	67	(7)	(54)
Foreign	(37)	31	4
	(267)	(44)	(618)
Total income taxes	$(289)	$ 14	$ (484)

Effective Tax Rate Reconciliation. Our income taxes, included in loss from continuing operations, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2005	2004	2003
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$(347)	$(285)	$(381)
Increase (decrease)			
Sales and write-offs of foreign investments	(7)	14	(53)
Valuation allowances	91	18	(57)
Foreign income taxed at different rates	115	144	(20)
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(37)	(18)	(13)
Audit settlements[1]	(58)	—	—
Non-deductible goodwill impairments	—	139	29
Non-taxable medicare reimbursements	(25)	—	—
Other	(21)	2	11
Income taxes	$(289)	$ 14	$(484)
Effective tax rate	29%	(2)%	44%

(1) We finalized The Coastal Corporation's IRS tax audits for years prior to 1997, and as a result, recorded a tax benefit of approximately $58 million in 2005.

Deferred Tax Assets and Liabilities. The following are the components of our net deferred tax liability related to continuing operations as of December 31:

	2005	2004
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$3,299	$2,565
Investments in unconsolidated affiliates	192	410
Regulatory and other assets	321	327
Total deferred tax liability	3,812	3,302
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,101	1,194
State	204	174
Foreign	76	35
Environmental liability	159	174
Price risk management activities	573	—[1]
Legal and other reserves	280	124
Other	601	783
Valuation allowance	(164)	(51)
Total deferred tax asset	2,830	2,433
Net deferred tax liability	$ 982	$ 869

(1) As of December 31, 2004, we had a net deferred tax liability associated with our price risk management activities which was included as part of Regulatory and other assets above.

Prior to 2004, we had not recorded U.S. deferred tax assets or liabilities on book versus tax basis differences for a substantial portion of our international investments based on our intent to indefinitely reinvest earnings from these investments outside the U.S. However, based on sales negotiations on certain of our Asian and Central American power assets, we have received or expect to receive these sales proceeds within the U.S. During the years ended December 31, 2005 and 2004, our effective tax rate was impacted upon recording U.S. deferred tax assets and liabilities on book versus tax basis differences in these investments based on the status of these negotiations. We also recorded U.S. deferred tax benefits on the sale of a power asset in India. As of December 31, 2005 and 2004, we have U.S. deferred tax assets of $103 million and $6 million and U.S. deferred tax liabilities of $23 million and $39 million related to these investments.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian and Central American 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, and an estimate of the taxes if earnings were to be repatriated is not practical. At December 31, 2005, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $121 million. 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.

Tax Credit and NOL Carryovers. As of December 31, 2005, we have U.S. federal alternative minimum tax credits of $303 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, 2005:

	Carryover Period				
	2006	2007-2010	2011-2015	2016-2025	Total
			(In millions)		
U.S. federal net operating loss	$—	$ 10	$ 15	$2,745	$2,770
State net operating loss	126	699	553	1,236	2,614

We also had $225 million of foreign net operating loss carryovers of which $192 million carryover indefinitely, $30 million carryover through 2007, and the remainder carryover through 2008 and 2009. 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.

Valuation Allowances. Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances, due to the effect of future reversals of existing taxable temporary differences primarily related to depreciation.

During 2005, we recorded foreign deferred tax assets on our Macae project (which is anticipated to be sold in 2006) from the generation of tax loss carryforwards and differences in the book and tax basis of fixed assets due to the impairment of the project. At this time, we recorded a full valuation allowance of $51 million on these assets as we do not expect to generate sufficient future taxable income to realize them. We recorded a state valuation allowance on deferred state tax assets generated in 2005, and recorded additional valuation allowances on existing deferred state tax assets due to changes in expected revenue allocations for future periods.

Other Tax Matters. The IRS has audited The Coastal Corporation's 1998-2000 tax years and El Paso Corporation's 2001 and 2002 tax years, and these audits are pending finalization with the IRS Appeals Office. We anticipate that these audits will be finalized in either 2006 or 2007. In addition, the IRS is currently auditing El Paso's 2003 and 2004 tax years. We have recorded a liability for tax contingencies associated with these audits, as well as for proceedings and examinations with other taxing authorities, which management believes is adequate. As these matters are finalized, we may be required to adjust our liability which could significantly increase or decrease our income tax expense in future periods.

8. Earnings Per Share

We incurred losses from continuing operations during the three years ended December 31, 2005. Accordingly, we excluded a number of securities for the years ended December 2005, 2004, and 2003 from the determination of diluted earnings per share due to their antidilutive effect on loss per common share. These included stock options, restricted stock, trust preferred securities, equity security units, and convertible debentures. Additionally, in 2005 we excluded our convertible preferred stock, which has conversion features discussed in Note 18, and in 2003, we excluded shares related to our remaining stock obligation under the Western Energy Settlement. For a further discussion of these instruments, see Notes 14 and 19.

9. Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31, 2005 and 2004.

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$18,234	$18,678	$19,189	$19,829
Commodity-based price risk management derivatives	(1,416)	(1,416)	68	68
Interest rate and foreign currency derivatives	2	2	239	239
Investments	61	61	47	47

As of December 31, 2005 and 2004, our carrying amounts of cash and cash equivalents, short-term borrowings, 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 10 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities. Our investments primarily relate to available for sale securities and cost basis investments.

10. 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, 2005 and 2004. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps, tolling agreements (assigned to a third party in 2005) and other natural gas and power purchase and supply contracts, our historical energy trading activities and our power contract restructuring activities (which were fully disposed of in 2004 and 2005). Finally, interest rate and foreign currency derivatives consist of swaps that are primarily designated as hedges of our interest rate and foreign currency risk on long-term debt.

	2005	2004
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (653)	$ (536)
Other commodity-based derivative contracts[(1)]	(763)	604
Total commodity-based derivatives	(1,416)	68
Interest rate and foreign currency derivatives[(2)]	2	239
Net assets (liabilities) from price risk management activities[(3)]	$(1,414)	$ 307

(1) Decrease is due primarily to the sale or assignment of a number of derivative contracts and significant changes in natural gas and oil prices during 2005.

(2) Decrease is due to settlement of hedge contracts upon repurchase of related debt as discussed below.

(3) 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. Historically, we used commodity prices from market-based sources such as the New York Mercantile Exchange for forward pricing data within two years. For forecasted settlement prices beyond two years, we used a combination of commodity prices from market-based sources and other independent pricing sources to develop price curves. The curves were then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discounted these estimated settlement values using a LIBOR curve for the majority of our derivative contracts or by using an adjusted risk-free rate for our restructured power contracts. Additionally, contracts denominated in foreign currencies were converted to U.S. dollars using market-based, foreign exchange spot rates.

Effective April 1, 2005, we began using new forward pricing data provided by Platts Research and Consulting, our independent pricing source, due to their decision to discontinue the publication of the pricing data they had provided to us in prior periods. In addition, due to the nature of the new forward pricing data, we extended the use of that data over the entire contractual term of our derivative contracts. Prior to April 1, 2005, we only used Platts' pricing data to value our derivative contracts beyond two years. Based on our analysis, the overall impact of this change in estimate was not material to our financial statements.

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.

Derivatives Designated as Hedges

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure, which primarily relate to our natural gas and oil production hedges and interest rate risks on our long-term debt, 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. Hedges of fair value exposure are entered into to protect the fair value of a recognized asset, liability or firm commitment. When we enter into the derivative contract, we may designate the derivative as either a cash flow hedge or a fair value hedge. Our hedges of our interest rate and foreign currency exposure are designated as either cash flow hedges or fair value hedges based on whether the interest on the underlying debt is converted to either a fixed or floating interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income (loss) to the extent that they are effective and then recognized in earnings when the hedged transactions occur. The ineffective portion of a cash flow hedge's change in value, if any, is recognized immediately in earnings as a component of operating revenues or interest and debt expense in our income statement. Changes in the fair value of derivatives that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of the related hedged assets, liabilities or firm commitments.

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 regularly 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 discontinue the hedging relationship.

A discussion of each of our hedging activities is as follows:

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets as well as fluctuations in foreign currency and interest rates with the objective of realizing a fixed cash flow stream from these activities. 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, 2005 and 2004 follows.

	Accumulated Other Comprehensive Income (Loss) 2005	Accumulated Other Comprehensive Income (Loss) 2004	Estimated Income (Loss) Reclassification in 2006[1]	Final Termination Year
	(In millions)			
Commodity cash flow hedges				
Held by consolidated entities[2]	$(285)	$54	$(220)	2012
Held by unconsolidated affiliates	(7)	(8)	2	2013
Total commodity cash flow hedges	(292)	46	(218)	
Interest rate and foreign currency cash flow hedges				
Fixed rate[3]	2	4	—	2015
Undesignated	(4)	(8)	—	2009
Total foreign currency cash flow hedges	(2)	(4)	—	
Total[4]	$(294)	$42	$(218)	

(1) Reclassifications occur upon the physical delivery of the hedged commodity and the corresponding expiration of the hedge or if the forecasted transaction is no longer probable.

(2) We have a derivative that hedges a portion of the production owned by UnoPaso, a wholly-owned subsidiary that owns natural gas and oil properties in Brazil. As a result of the earlier than expected payout of certain of UnoPaso's natural gas and oil properties, which will reduce our interest in the properties and related anticipated production volumes, we recorded an $11 million loss in the third quarter of 2005 related to the elimination of the accumulated other comprehensive loss associated with this hedge and reclassified the hedge as an other commodity-based derivative contract.

(3) In March 2005, we repurchased approximately €528 million of debt, of which €375 million was hedged with interest rate and foreign currency derivatives. As a result of the repurchase, we removed the hedging designation on these derivatives and settled substantially all of the contracts. We recorded a gain of approximately $2 million during the first quarter of 2005 upon the reversal of the related accumulated other comprehensive income associated with these derivatives.

(4) Accumulated other comprehensive income (loss) also includes: a) $(4) million and $5 million of net cumulative foreign currency translation adjustments as of December 31, 2005 and 2004; b) $(49) million and $(46) million of additional minimum pension liability as of December 31, 2005 and 2004; and c) $15 million of unrealized gains related to an available for sale security as of December 31, 2005. All amounts are net of taxes.

In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as cash flow hedges, beginning in the fourth quarter of 2004.

For the years ended December 31, 2005, 2004 and 2003, we recognized net losses of $5 million, $1 million and $2 million, net of income taxes, in our loss from continuing operations related to the ineffective portion of our commodity cash flow hedges. We did not record any ineffectiveness related to our interest rate or foreign currency cash flow hedges in 2003, 2004 and 2005.

Fair Value Hedges. We have fixed rate U.S. dollar and foreign currency denominated debt that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps to effectively convert the fixed amounts of interest due under the debt agreements to variable interest payments based on LIBOR plus a spread. As of December 31, 2005 and 2004, these derivatives had a net fair value loss of $7 million and gain of $117 million. Specifically, we had derivatives with fair value losses of $30 million and $20 million as of December 31, 2005 and 2004, that converted the interest rate on $440 million of our U.S. dollar denominated debt to a floating weighted average interest rate of LIBOR plus 4.2%. Additionally, we had derivatives with fair values of $23 million and $137 million as of December 31, 2005 and 2004, that converted approximately €350 million and €450 million of our debt to $402 million and $511 million. These derivatives also converted the interest rate on this debt to a floating weighted average interest rate of LIBOR plus 4.2% as of December 31, 2005, and LIBOR plus 3.9% as of December 31, 2004. We have recorded the fair value of those derivatives as a component of long-term debt and the related accrued interest.

In March 2005, we repurchased approximately €528 million of debt, of which approximately €100 million were hedged with fair value hedges. As a result of the repurchase, we removed the hedging designation on, and subsequently settled, these derivative contracts.

Other Commodity-Based Derivatives

Our other commodity-based derivatives primarily relate to our historical trading activities, which include the services we provide in the energy sector that we entered into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities. Additionally, they include derivatives related to our historical power contract restructuring activities and other derivative contracts not designated as hedges, including our production-related option and swap contracts held by our Marketing and Trading segment.

During 2001 and 2002, we conducted power contract restructuring activities that involved amending or terminating power purchase contracts at existing power facilities. As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and during 2005, we disposed of our remaining historical restructured power contracts. Specifically, during 2005, we sold or assigned derivative contracts with a net fair value of $376 million in conjunction with the sales of Cedar Brakes I and II and Mohawk River Funding II entities. See Note 3 for a discussion of these sales, which include the sales of UCF, Cedar Brakes I and II and our other power restructuring entities that owned derivative contracts.

Additionally, during 2005, we entered into agreements to assign a number of our other derivative contracts not designated as hedges. Specifically, we (i) completed the assignment of our liability under the Cordova tolling agreement for which we paid $177 million and (ii) entered into an agreement to assign the majority of our power derivative assets to Morgan Stanley. This assignment requires the consent of existing third parties before the contracts can be transferred to Morgan Stanley. Until the assignment is finalized, we entered into offsetting liability contracts with Morgan Stanley to eliminate the commodity price risk associated with the contracts being assigned. We received total proceeds of $442 million to enter into these offsetting contracts and deposited a similar amount of cash margin. The amount received approximated the value we would have received if we had directly sold our power derivative assets. We expect to complete this assignment to Morgan Stanley in the first half of 2006.

During the first quarter of 2006, we assigned our contracts to supply natural gas to the Jacksonville Electric Authority and The City of Lakeland, Florida for no cash consideration. We will record a gain of approximately $50 million related to this assignment in 2006.

Credit Risk

We are subject to credit risk related to our financial instrument assets. Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We measure credit risk as the estimated replacement costs for commodities we would have to purchase or sell in the future, plus amounts owed from counterparties for delivered and unpaid commodities. These exposures are netted where we have a legally enforceable right of setoff. We maintain credit policies with regard to our counterparties in our price risk management activities to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition (including credit rating), (ii) collateral under certain circumstances (including cash in advance, letters of credit, and guarantees), (iii) the use of margining provisions in standard contracts, and (iv) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

We use daily margining provisions in our financial contracts, most of our physical power agreements and our master netting agreements, which require a counterparty to post cash or letters of credit when the fair value of the contract exceeds the daily contractual threshold. The threshold amount is typically tied to the published credit rating of the counterparty. Our margining collateral provisions also allow us to terminate a contract and liquidate all positions if the counterparty is unable to provide the required collateral. Under our margining provisions, we are required to return collateral if the amount of posted collateral exceeds the amount of collateral required. Collateral received or returned can vary significantly from day to day based on the changes in the market values and our counterparty's credit ratings. Furthermore, the amount of collateral we hold may be more or less than the fair value of our derivative contracts with that counterparty at any given period.

The following table presents a summary of our derivative counterparties in which we had net asset exposure as of December 31, 2005 and 2004.

Counterparty	Net Derivative Instrument Asset Exposure			
	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2005				
Energy marketers	$ 554	$110	$ —	$ 664
Natural gas and electric utilities	6	—	134	140
Commodity exchanges	515	—	—	515
Other	45	—	1	46
Net financial instrument assets[2]	1,120	110	135	1,365
Collateral held by us	(831)	(96)	(68)	(995)
Net exposure from derivative assets	$ 289	$ 14	$ 67	$ 370

Counterparty	Net Derivative Instrument Asset Exposure			
	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2004				
Energy marketers	$ 440	$ 44	$ 35	$ 519
Natural gas and electric utilities	424	—	91	515
Commodity exchanges	242	—	—	242
Other	3	—	7	10
Net financial instrument assets[2]	1,109	44	133	1,286
Collateral held by us	(349)	(39)	(81)	(469)
Net exposure from derivative assets	$ 760	$ 5	$ 52	$ 817

(1) "Investment Grade" and "Below Investment Grade" are determined using publicly available credit ratings. "Investment Grade" includes counterparties with a minimum Standard & Poor's rating of BBB− or Moody's rating of Baa3. "Below Investment Grade" includes counterparties with a public credit rating that do not meet the criteria of "Investment Grade". "Not Rated" includes counterparties that are not rated by any public rating service.

(2) Net asset exposure from financial instrument assets primarily relates to our assets and liabilities from price risk management activities. These exposures have been prepared by netting assets against liabilities on counterparties where we have a contractual right to offset. The positions netted include both current and non-current amounts and do not include amounts already billed or delivered under the derivative contracts, which would be netted against these exposures.

We have approximately 95 counterparties as of December 31, 2005, most of which are energy marketers. Although most of our counterparties are not currently rated as below investment grade, if one of our counterparties fails to perform, we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and quantities cannot be established.

As of December 31, 2005, two energy marketers, Constellation Energy Commodities Group, Inc. and Duke Energy Trading and Marketing LLC, comprised 28 percent and 18 percent of our net financial instrument asset exposure. As of December 31, 2004, one electric utility customer, Public Service Electric and Gas Company (PSEG), comprised 42 percent of our net financial instrument asset exposure; however, this exposure to PSEG was eliminated with the sale of our interests in Cedar Brakes I and II in 2005. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

11. Regulatory Assets and Liabilities

Our regulatory assets and liabilities relate to our interstate pipeline subsidiaries that apply the provisions of SFAS No. 71 and are included in other current and non-current assets and liabilities on our balance sheets. These balances are presented on our balance sheets on a gross basis and are recoverable over various periods. Below are the details of our regulatory assets and liabilities as of December 31:

Description	2005	2004
	(In millions)	
Current regulatory assets	$ 4	$ 3
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction	96	85
Postretirement benefits	25	30
Unamortized net loss on reacquired debt	20	23
Under-collected state income tax	7	7
Other	16	10
Total non-current regulatory assets	164	155
Total regulatory assets	$168	$158
Current regulatory liabilities	$ 9	$ 9
Non-current regulatory liabilities		
Environmental liability	110	97
Cost of removal of offshore assets	48	50
Property and plant depreciation	41	35
Postretirement benefits	16	13
Plant regulatory liability	11	11
Excess deferred income taxes	8	11
Other	8	11
Total non-current regulatory liabilities	242	228
Total regulatory liabilities	$251	$237

12. Other Assets and Liabilities

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

	2005	2004
	(In millions)	
Other current assets		
Prepaid expenses	$ 90	$ 119
Restricted cash (Note 1)	281	180
Inventory	140	155
Other	26	47
Total	$ 537	$ 501
Other non-current assets		
Pension assets (Note 17)	$ 886	$ 933
Notes receivable from affiliates	263	287
Restricted cash (Note 1)	168	180
Unamortized debt expenses	176	192
Regulatory assets (Note 11)	164	155

	2005	2004
	(In millions)	
Long-term receivables	410	316
Assets of discontinued operations (Note 3)	—	298
Other	197	262
Total	$2,264	$2,623
Other current liabilities		
Accrued taxes, other than income	$ 109	$ 135
Western Energy Settlement	—	44
Income taxes	52	80
Environmental, legal and rate reserves (Note 16)	181	84
Deposits	31	39
Other postretirement benefits (Note 17)	35	38
Accrued lease obligations	43	4
Asset retirement obligations (Note 1)	33	28
Dividends payable	35	25
Accrued liabilities	36	74
Other	124	175
Total	$ 679	$ 726
Other non-current liabilities		
Environmental and legal reserves (Note 16)	$1,028	$ 763
Western Energy Settlement	—	351
Other postretirement and employment benefits (Note 17)	224	249
Regulatory liabilities (Note 11)	242	228
Asset retirement obligations (Note 1)	194	244
Other deferred credits	186	126
Accrued lease obligations	77	126
Insurance reserves	132	125
Liabilities related to discontinued operations (Note 3)	—	55
Other	188	185
Total	$2,271	$2,452

13. Property, Plant and Equipment

At December 31, 2005 and 2004, we had approximately $1.1 billion and $0.8 billion of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2005 and 2004, TGP, EPNG and ANR have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $5 billion and accumulated depreciation was approximately $1.4 billion and $1.3 billion at December 31, 2005 and 2004. These excess costs are being depreciated over the life of the pipeline assets we assigned the costs to, and our related depreciation expense for the years ended December 31, 2005, 2004, and 2003 was approximately $76 million, $76 million and $74 million. We do not currently earn a return on these excess purchase costs from our rate payers.

14. Debt, Other Financing Obligations and Other Credit Facilities

	2005	2004
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,211	$ 955
Long-term financing obligations	17,023	18,241
Total	$18,234	$19,196

A summary of changes in our debt is as follows (in millions):

Debt obligations as of December 31, 2004	$19,196
Principal amounts borrowed	1,638
Repayment/retirement of principal	(1,912)
Sale of entities[1]	(575)
Other	(113)
Total debt as of December 31, 2005	$18,234

[1] Related to the sale of Cedar Brakes I and II and Mohawk River Funding II.

Short-Term Financing Obligations

We had the following short-term borrowings and other financing obligations as of December 31:

	2005	2004
	(In millions)	
Current maturities of long-term debt and other financing obligations	$1,211	$ 948
Short-term financing obligation	—	7
	$1,211	$ 955

Long-Term Financing Obligations

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

	2005	2004
	(In millions)	
Long-term debt		
ANR Pipeline Company		
Debentures and notes, 7.0% through 9.625%, due 2010 through 2025	$ 732	$ 800
Notes, 13.75% due 2010	12	12
Colorado Interstate Gas Company		
Senior debentures, 10.0% and 6.85%, due 2005 and 2037	100	280
Senior notes, 5.95% and 6.80%, due 2015	600	—
El Paso CGP Company, L.L.C.[1]		
Notes, 6.5% through 7.75%, due 2006 through 2010	—	930
Senior debentures, 6.375% through 10.75%, due 2008 through 2037	—	1,357
El Paso Corporation		
Senior debentures, 6.375% through 10.75%, due 2008 through 2037	166[1]	—
Senior notes, 5.75% through 10.75%, due 2006 through 2037	3,439[1]	1,956
Equity security units, 6.14% due 2007	—	272
Notes, 6.50% through 7.875%, due 2005 through 2018	1,854[1]	1,952
Medium-term notes, 6.95% through 9.0%, due 2005 through 2032	2,735	2,784
Zero coupon convertible debentures due 2021	611	822
$1.25 billion term loan, LIBOR plus 2.75% due 2009	1,225	1,245

	2005	2004
	(In millions)	
El Paso Natural Gas Company		
Notes, 7.625% and 8.375%, due 2010 and 2032	655	655
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
El Paso Exploration & Production Company		
Senior notes, 7.75%, due 2013	1,200	1,200
Revolving credit facility, LIBOR plus 1.875% due 2010	500	—
Power		
Non-recourse senior notes, 8.5% and 9.875%, due 2013 and 2014	—	666
Non-recourse notes, variable rates, due 2007 and 2008	225	320
Recourse notes, 7.27% and 8.5%, due 2016	—	40
Southern Natural Gas Company		
Notes, 6.125% through 8.875%, due 2007 through 2032	1,200	1,200
Tennessee Gas Pipeline Company		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
Notes, 8.375%, due 2032	240	240
Other	325	137
	17,665	18,714
Other financing obligations		
Capital Trust I	325	325
Coastal Finance I	300	300
	625	625
Subtotal	18,290	19,339
Less:		
Unamortized discount and premium on long-term debt	56	150
Current maturities	1,211	948
Total long-term financing obligations, less current maturities	$17,023	$18,241

(1) Approximately $2.3 billion of El Paso CGP Company, L.L.C. debt was exchanged for El Paso debt or assumed by El Paso in December 2005.

During 2005 and to date in 2006, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value	Cash Received/Paid
			(In millions)	
Issuances				
Colorado Interstate Gas Company	Senior notes due 2015	5.95%	$ 200	$ 197
Cheyenne Plains Gas Pipeline Company[1]	Non-recourse term loan due 2015	Variable	266	261
El Paso Exploration & Production Company	Revolving credit facility due 2010	LIBOR +1.875%	500	495
El Paso[2]	Senior notes due 2007	7.625%	272	272
Colorado Interstate Gas Company	Senior notes due 2015	6.8%	400	395
	Increases through December 31, 2005		$1,638	$1,620

Company	Type	Interest Rate	Book Value	Cash Received/Paid
			(In millions)	
Repayments, repurchases, retirements and other				
El Paso	Zero coupon debentures[3]	—	$ 236	$ 237
El Paso	Notes	6.88%	167	167
Cedar Brakes I[4]	Non-recourse senior notes	8.5%	241	15
Cedar Brakes II[4]	Non-recourse senior notes	9.88%	334	14
Mohawk River Funding II[4]	Non-recourse note	9.0%	37	8
El Paso[5]	Euro notes	5.75%	695	722
El Paso[2]	Senior notes due 2007	6.14%	272	—
Colorado Interstate Gas Company	Senior debentures	10.00%	180	180
Other	Long-term debt	Various	438	325
	Decreases through December 31, 2005		$2,600	$1,668
Coastal Finance I	Trust originated preferred securities	8.375%	300	300
El Paso	Zero coupon debentures[3]	—	603	603
Other	Long-term debt	Various	2	2
	Decreases through February 28, 2006		$3,505	$2,573

(1) In addition to the borrowing, we have an associated letter of credit facility for $12 million, under which we issued $6 million of letters of credit in May 2005. We also concurrently entered into swaps to convert the variable interest rate on approximately $213 million of this debt to a current fixed rate of 5.94%.

(2) In July 2005, we remarketed $272 million of notes which originally formed a portion of our 9.0% equity security units. Existing note holders utilized proceeds from the remarketing to satisfy their obligation under the equity security units to purchase common stock which had the effect of exchanging debt for equity. We have reflected this transaction as a non-cash financing transaction and the issuance of the new remarketed notes as a financing cash inflow.

(3) This security has a yield-to-maturity of approximately 4%.

(4) Prior to the sale of Cedar Brakes I and II, and Mohawk River Funding II, we made $37 million of scheduled principal repayments. Upon the sale of these entities, the remaining balance of $575 million was eliminated.

(5) We recorded a $26 million loss on the early extinguishment of this debt.

We recorded accretion expense on our zero coupon bonds of $25 million and $36 million during the years ended December 31, 2005 and 2004. These amounts are added to the principal balance each period and are included in our long-term debt. We account for redemption of zero coupon debentures as a financing activity in our statement of cash flows, which included this accretion. During 2005, we redeemed $236 million of our zero coupon debentures of which $34 million represented increased principal due to the accretion of interest on the debentures.

Debt Maturities

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

2006	$ 1,211
2007	781
2008	676
2009	2,479
2010	2,058
Thereafter	11,085
Total long-term financing obligations, including current maturities	$18,290

Included above in 2006 is $225 million of debt associated with our Macae project in Brazil, which we have classified as current as a result of an event of default on Macae's non-recourse debt. (See Note 16 for additional details on the event of default.) Also included in 2006 maturities are approximately $0.6 billion of zero coupon debentures, which the holders required us to redeem in February 2006 for cash. Additionally, we have debt of approximately $600 million that is redeemable by holders in 2007, prior to its stated maturity, which is included in the "Thereafter" amount.

In addition to the debt we may be required to redeem prior to its maturity, we also have a number of our debt obligations that are callable by us prior to their stated maturity date. At this time, we have $12.3 billion of debt obligations callable in 2006 and an additional $0.6 billion callable in 2007 and thereafter. To the extent we decide to redeem any of this debt, certain obligations will require us to pay a make whole premium.

Credit Facilities

In November 2004, we entered into a $3 billion credit agreement consisting of a $1.25 billion five-year term loan; a $1 billion three-year revolving credit facility; and a $750 million, five-year letter of credit facility. Our subsidiaries, ANR, CIG, EPNG and TGP are eligible borrowers under this credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under this credit agreement, which is collateralized by our stock ownership in ANR, CIG, ANR Storage Company, EPNG, Southern Gas Storage Company and TGP.

As of December 31, 2005, we had $1.23 billion outstanding under the term loan and had utilized approximately all of the $750 million letter of credit facility and approximately all of the $1 billion revolving credit facility to issue letters of credit. The term loan accrues interest at LIBOR plus 2.75 percent, matures in November 2009 and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. The terms of the $750 million letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity under the letter of credit facility as revolving loans with a maturity in November 2009. We pay LIBOR plus 2.75 percent on any amounts borrowed under the letter of credit facility, and 2.85 percent on letters of credit and unborrowed funds.

In August 2005, our subsidiary EEPC entered into a $500 million five-year revolving credit facility bearing interest at LIBOR plus 1.875%. Under the facility, we borrowed $500 million, which was used to partially fund the acquisition of Medicine Bow. The facility can be utilized for funded borrowings or for the issuance of letters of credit and is collateralized by certain EEPC natural gas and oil production properties.

In November 2005, we entered into a $400 million revolving borrowing base credit agreement collateralized by natural gas and oil production properties owned by one of our subsidiaries, which is also a co-borrower. Under the agreement we have initial borrowing availability of $300 million. While we have not drawn any amounts under this credit facility it can be used for revolving credit loans or for the issuance of letters of credit and will mature in May 2006. If fully drawn, the interest rate on this facility would be LIBOR plus 2.50%.

Restrictive Covenants

$3 billion revolving credit facility. Our restrictive covenants under the $3 billion revolving credit facility include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, dividend restrictions, cross default, cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our credit agreement the significant debt covenants and cross defaults are:

(a) El Paso's ratio of Debt to Consolidated EBITDA, (each as defined in the credit agreement), shall not exceed 6.25 to 1.0 at any time on or after September 30, 2005, and prior to June 30, 2006, and 6.0 to 1.0 at any time on or after June 30, 2006, until maturity;

(b) El Paso's ratio of Consolidated EBITDA, (as defined in the credit agreement), to interest expense plus dividends paid shall not be less than 1.6 to 1.0 prior to March 31, 2006, 1.75 to 1.0 on or after March 31, 2006, and prior to March 31, 2007, and 1.8 to 1.0 on or after March 31, 2007, until maturity;

(c) EPNG, TGP, ANR and CIG cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, (each as defined in the credit agreement), for that particular company to exceed 5.0 to 1.0;

(d) the proceeds from the issuance of Debt by our pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt; and

(e) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to Debt in an aggregate principal amount of $200 million or more.

$500 million credit facility. The availability of borrowings under this facility is subject to various conditions. The financial coverage ratio under the facility requires that EEPC's EBITDA (as defined in the facility) to interest expense not be less than 2.0 to 1.0, EEPC's debt to EBITDA must not be greater than 4.5 to 1.0 until September 30, 2006, and 4.0 to 1.0 thereafter, and EEPC's Collateral Coverage Ratio (as defined in the facility) must be greater than 1.5 to 1.0.

$400 million credit agreement. The availability of borrowings under this facility is subject to various conditions. One of the more restrictive new covenants of this facility is the requirement to maintain a Collateral Coverage Ratio (as defined in the facility) of at least 1.5 to 1.0.

Other Restrictions and Provisions. In addition to the above restrictions and default provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of 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 our cash management program, and limitations on our ability to prepay debt.

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

Our most restrictive acceleration provision is $5 million and is associated with the indenture of one of our subsidiaries. This indenture states that should an event of default occur resulting in the acceleration of other debt obligations in excess of $5 million, the long-term debt obligation containing that provision could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

Other Financing Arrangements

Capital Trusts. El Paso Energy Capital Trust I (Trust I), is a wholly owned business trust formed in March 1998. Trust I issued 6.5 million of 4.75 percent trust convertible preferred securities in a public offering for $325 million. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We also have two wholly owned business trusts, El Paso Energy Capital Trust II and III (Trust II and III), under which we have not issued securities. We provide a full and unconditional guarantee of Trust I's preferred securities, and would provide the same guarantee if securities were issued under Trust II and III.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 percent, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I preferred security (equivalent to a conversion price of $41.59 per common share). We have classified these securities as long-term debt and we have the right to redeem these securities at any time.

Coastal Finance I. Coastal Finance I is an indirect wholly owned business trust formed in May 1998. Coastal Finance I issued in a public offering 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I held subordinated debt securities issued by our wholly owned subsidiary, El Paso CGP, L.L.C., that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions were being paid on the preferred securities at an annual rate of 8.375 percent of the liquidation amount of $25 per preferred security. On February 8, 2006, the $300 million of outstanding preferred securities were redeemed.

Non-Recourse Project Financings. Many of our subsidiaries and investments have debt obligations related to their costs of construction or acquisition. Several of our projects have experienced events that have either constituted or could constitute an event of default under the loan agreements. Among other projects, our consolidated Macae project in Brazil and our Berkshire project have been either issued a notice of default or experienced an event of default. Our outstanding debt at our consolidated Macae project is $225 million at December 31, 2005. This debt (as well as other project financing debt) is recourse only to the project company and assets (i.e. without recourse to El Paso). We do not believe any of these defaults, or other events that have led to or could lead to events of default at other projects, will have a material effect on us or our subsidiaries' financial statements based on the amounts we have recorded on our balance sheet for these projects and/or the current status of negotiations relating to these projects (for a further discussion, see Notes 16 and 21).

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of December 31, 2005, we had outstanding letters of credit of approximately $2.0 billion, of which $1.7 billion were issued under our credit agreement. Included in this amount is $1.2 billion of letters of credit securing our recorded obligations related to price risk management activities.

15. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into transactions accomplished through the sale of preferred interests in consolidated subsidiaries. During 2003, approximately $3 billion of these preferred interests were redeemed, reclassified to long-term debt or eliminated through various actions. In May 2005, we redeemed $300 million of 8.25% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co.

16. Commitments and Contingencies

Legal Proceedings

Shareholder/ Derivative/ ERISA Litigation

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. This consolidated lawsuit, which alleges violations of federal securities laws against us and several of our current and former officers and directors, includes allegations regarding the accuracy or completeness of press releases and other public statements made during the class period from 2000 through early 2004 related to alleged wash trades, mark-to-market accounting, off-balance sheet debt, the overstatement of natural gas and oil reserves and manipulation of the California energy market. Formal discovery in the consolidated lawsuit is currently stayed. The Court has ordered the parties to mediate this case in April 2006.

Derivative Litigation. Since 2002, six shareholder derivative actions have also been filed. Two of these actions were filed in federal court in Houston, two were filed in state court in Houston, and two were filed in Delaware Chancery Court. Only three of these actions remain following consolidation and dismissal of the other cases.

- *The Houston federal court cases:* The first federal court case was filed in 2002 and the second was filed in 2004. The 2002 federal court case generally alleges the same claims pled in the consolidated shareholder class action described above, with the exception that there are no allegations related to the overstatement of natural gas and oil reserves. The 2004 federal court case includes allegations related to the overstatement of natural gas and oil reserves, in addition to the allegations alleged in the 2002 federal court case. The two federal court actions in Houston are both currently stayed.

- *The Houston state court cases:* The two state court actions in Houston have been consolidated. The plaintiffs in those cases originally alleged that the manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. The plaintiffs in the consolidated state court case recently amended their petition to add claims of unjust enrichment of certain former executives allegedly attributable to round trip trading and restructuring of energy contracts and breach of fiduciary duty claims for failure to recover 2001 compensation paid to certain officers and related to the overstatement of natural gas and oil reserves. Discovery is ongoing in this case.

- *The Delaware Chancery Court cases:* The first of these two cases was filed in 2002, and generally alleges the same claims pled in the consolidated shareholder class action described above, with the exception that there were no allegations related to the overstatement of natural gas and oil reserves. This lawsuit was voluntarily dismissed by plaintiffs in July 2005. The second Delaware derivative case was filed in April 2005 and seeks to recover the compensation paid to a former executive in 2001 alleging unjust enrichment allegedly attributable to round trip trading and restructuring of energy contracts and breach of fiduciary duty claims for failure to seek recovery of the 2001 compensation. In December 2005, the court dismissed this lawsuit because of the plaintiffs' failure to make demand on the Board of Directors before filing suit.

ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. Formal discovery in this lawsuit is currently stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits subject to certain deductibles and co-pay obligations. We have established certain accruals for these matters, which we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation*. The suit alleges, among other things, that El Paso and Case violated ERISA and that they should be required to pay all amounts above the cap. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend and hold Case harmless for the amounts it would be required to pay. In separate rulings in 2004, the court ruled that pending a trial on the merits Case must pay the amounts incurred above the cap and that El Paso must reimburse Case for those payments. In January 2006, these rulings were upheld on appeal before a 3-member panel of the U.S. Court of Appeals for the 6th Circuit. In February 2006, we filed for a review of this decision by the full panel of the U.S. Court of Appeals for the 6th Circuit as a result of conflicting precedent. The appellate court has requested that the plaintiff file a reply brief in March 2006. If such a review is not granted, we will proceed with a trial on the merits with regard to the issue of whether the cap is enforceable. Until this is resolved, El Paso will indemnify Case for any payments Case makes above the cap, which are currently about $1.7 million per month. While we will continue to defend the action, based upon the ruling of the 6th Circuit and the lessening avenues of appellate reviews, we recorded a pre-tax charge of approximately $350 million for this matter during the fourth quarter of 2005. We have also filed for approval by the trial court various amendments to the medical benefit plans which would allow us to deliver the benefits to plan participants in a more cost effective manner. We will seek expeditious approval of such plan amendments. Although it is uncertain what plan amendments will ultimately be approved, the approval of plan amendments could reduce our overall costs and, as a result, could reduce our recorded liability.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits have been filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. The first set of cases were filed in the United States District Court for the Southern District of New York which included: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*;*Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. The consolidated cases are styled, *in re: Gas Commodity Litigation.* In September 2004, El Paso Corporation was dismissed from the master case. In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. EPM and the remaining defendants have petitioned the United States Court of Appeals for the Second Circuit for permission to appeal the class certification order. The second set of cases involve similar allegations on behalf of commercial and residential customers. These cases were filed in the U.S. District Court for the Eastern District of California, which include *Texas Ohio Energy, Inc. v. CenterPoint Energy, Inc. et al.* (filed in November 2003), *Fairhaven Power v. El Paso Corporation et al.* (filed in September 2004), *Utility Savings and Refund Services, et al. v. Reliant Energy, et al.* (filed in December 2004) and *Abelman Art Glass, et al. v. Encana Corporation, et al.* (filed in December 2004). Each of these cases was transferred to a multi-district litigation proceeding (MDL), *In re Western States Wholesale Natural Gas Antitrust Litigation*, pending in the U.S. District Court for Nevada. These cases have been dismissed and have been appealed. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include a purported class action lawsuit styled *Leggett et al. v. Duke Energy Corporation et al.* (filed in Chancery Court of Tennessee in January 2005), *Ever-Bloom Inc. v. AEP Energy Services Inc. et al.* (filed in June 2005), *Farmland Industries, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in July 2005) and the purported class action *Learjet, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in September 2005). All four actions have been transferred to the MDL proceeding in federal district court in Nevada. Similar motions to dismiss have either been filed or are anticipated to be filed in these cases as well. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties due to the alleged mismeasurement. The plaintiff seeks royalties along with interest, expenses, and punitive damages. The plaintiff also seeks injunctive relief with regard to future 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 were argued before a representative appointed by the court. In May 2005, the representative issued its recommendation, which if adopted by the district court judge, will result in the dismissal on jurisdictional grounds of six of the seven *Qui Tam* actions filed by Grynberg against El Paso subsidiaries. The seventh case involves only a few midstream entities owned by El Paso, which have meritorious defenses to the underlying claims. If the district court judge adopts the representative's recommendations, an appeal by the plaintiff of the district court's order is likely. 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 in April 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 petition has since been filed as to the heating content claims. Motions for class certification have been briefed and argued in both proceedings, and the parties are awaiting the court's ruling. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Hurricane Litigation. One of our affiliates has been named in two class action petitions (subsequently consolidated by the court into one action) for damages filed in the United States District Court for the Eastern District of Louisiana against all natural gas and oil pipeline and exploration and production companies that dredged pipeline canals, installed transmission lines or drilled for natural gas and oil in the marshes of coastal Louisiana. The lawsuits, *George Barasich, et al. v. Columbia Gulf Transmission Company, et al.* and *Charles Villa Jr., et al. v. Columbia Gulf Transmission Company, et al.* assert that the defendants caused erosion and land loss which destroyed critical protection against hurricane surges and winds and was a substantial cause of the loss of life and destruction of property. The first lawsuit alleges damages associated with Hurricane Katrina. The second lawsuit alleges damages associated with Hurricanes Katrina and Rita. Our costs and legal exposures related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc. (Burlington), in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.*, and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.*, each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The consolidated class action has been settled pursuant to a settlement agreement executed in January 2006. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. All the claims in this action have also been settled as part of the January 2006 settlement. The settlement of all these claims is subject to court approval, after a fairness hearing anticipated in the spring of 2006. We filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County, Texas relating to indemnity issues between Burlington and us. That action was stayed by agreement of the parties and settled in November 2005, subject to the underlying class settlements being finalized and approved by the court. Upon final court approval of these settlements, our contribution will be approximately $30 million, which has been accrued as of December 31, 2005.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility, COPEL. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA. The final arbitration hearing was held in January 2006. A Curitiba court has ruled that the arbitration clause in the PPA is invalid. The project company is appealing this ruling. In February 2006, El Paso signed a letter of intent to settle this matter and to sell its interest in Araucaria to COPEL for $190 million. The sale is subject to negotiations of definitive purchase and sale agreements and requisite corporate approvals and its consummation would be subject to customary conditions to closing, including receipt of any necessary government approvals. The letter of intent provides that the parties will complete and sign definitive purchase and sale agreements by mid-April and that in the interim, the Araucaria arbitration will be suspended.

Our investment in the Araucaria project was $187 million at December 31, 2005. We have political risk insurance that covers a substantial portion of our investment in the project. Based on the future outcome of our dispute under the PPA and the letter of intent and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil. The Macae project revenues are derived, in part, from minimum capacity and revenue payments made by Petrobras under a participation agreement that extends through August 2007. Petrobras filed a notice of arbitration that seeks rescission of the participation agreement and reimbursement of some or all of the capacity payments that it has made. An arbitration hearing took place in October 2005 and the arbitrators issued a partial final award on certain issues raised in the arbitration in November 2005. A final hearing is scheduled for late April 2006 on the remaining issues in the arbitration. We believe we have substantial defenses to the claims of Petrobras and continue to defend our legal rights vigorously. If, however, Petrobras' claims were successful, they could result in a termination of the minimum revenue payments as well as Petrobras' obligation to provide firm natural gas supply to the project through 2012.

On February 1, 2006, El Paso and Petrobras signed a memorandum of understanding that provides for the settlement of this matter and the sale of the entities that own El Paso's interest in the Macae power plant. El Paso would sell these entities for a purchase price of approximately $358 million, adjusted for working capital, and approximately $225 million of project financing would be repaid from those sales proceeds. The sale is subject to negotiations of definitive purchase and sale agreements and requisite corporate approvals and its consummation would be subject to customary conditions to closing, including receipt of any necessary government approvals. We and Petrobras will attempt to complete the definitive agreements in March 2006 and in the interim, the arbitration proceedings will be suspended.

Based on the status of the arbitration proceedings and the indication of value we may ultimately receive for the settlement of this matter described in the memorandum of understanding, we recorded $333 million of impairment charges in 2005 on our investment in the Macae facility. In addition, we did not recognize approximately $206 million of revenues under our participation agreement during 2005 and reserved $18 million of related receivables because of the uncertainty about their collectibility. Depending on the terms of the final agreement, we could be required to record additional losses related to the disposition and the resolution of disputes related to Macae.

Pending the issuance of the final arbitration award or the sale of Macae under the memorandum of understanding, Petrobras has been depositing the amounts owed directly into a restricted cash account, subject to Macae's obligation to post a bank guarantee as security for any repayment obligation if Petrobras prevails in the dispute. We have recorded a liability of $186 million and the same amount in restricted cash related to these payments in addition to $1 million of debt service reserves held by Macae in their restricted cash accounts. We have reflected payments by Petrobras into this account as a non-cash investing transaction for purposes of our cash flow statement.

Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the debt as current. In light of the default of Petrobras under the participation agreement and the inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project. In February 2006, Macae's lenders issued notices of default due to the project's non-payment of scheduled principal and interest payments and the lenders are reserving all of their rights under the loan agreements. In the event that the lenders foreclose on the project, we may incur additional losses of up to approximately $141 million. As new information becomes available or future material developments occur, we will reassess the carrying value of our interests in this project.

In late 2005, Macae also received an assessment from the Brazilian tax authorities totaling approximately $73 million, including $18 million for various import taxes and $55 million for interest and penalties related to the importation of equipment for the Macae plant during its construction. We believe we have valid defenses against the amounts assessed and have filed an appeal of the assessment to the administrative level of the Brazilian tax authorities and, accordingly, we have not accrued a liability related to this claim. In addition, we are pursuing a refund of tax payments that have been made related to interest income that the supreme court in Brazil, in a similar case, has recently determined to be unconstitutional. We have not accrued a receivable related to this potential tax receivable as collectibility is not assured. This tax claim, including interest that has accrued on these tax payments, totals approximately $21 million.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, certain of our subsidiaries used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of their gasoline. Certain subsidiaries 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. Some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued in March 2004, these suits have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, 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. Among other allegations, plaintiffs assert that gasoline containing MTBE is a defective product and that defendant refiners are liable in proportion to their market share. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. In April 2005, the judge denied a motion by defendants to dismiss the lawsuits. In that opinion the Court recognized, for certain states, a potential commingled product market share basis for collective liability. Our costs and legal exposure related to these lawsuits are not currently determinable.

Government Investigations

Round Trip Trades. In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. On May 24, 2005, we received a subpoena from the SEC requesting the production of documents related to certain hedges on our natural gas production. We are cooperating with the SEC investigation.

Price Reporting. We have provided information to the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests for information regarding price reporting of transactional data to the energy trade press. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney's investigation of this matter.

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We will continue to cooperate with the SEC in its investigation related to such reserve revisions. Although we had also received federal grand jury subpoenas for documents with regard to these reserve revisions, in June 2005, we were informed that the U.S. Attorney's office closed this investigation and will not pursue prosecution at this time.

Iraq Oil Sales. In September 2004, Coastal (which we acquired in January 2001) 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 Nations' Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records related 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 Coastal Corporation's and El Paso's participation in the Oil for Food Program. In June and December 2005, we received additional requests for documents and information from the SEC. We have also received informal requests for information and documents from several congressional committees related to Coastal's purchases of Iraqi crude under the Oil for Food Program. In October 2005, a grand jury sitting in the Southern District of New York handed down an indictment against Oscar S. Wyatt, Jr., a former CEO and Chairman of Coastal. Also in October 2005, the Independent Inquiry Committee into the United Nations' Oil for Food Program issued its final report. The report states that $201,877 in surcharges were paid with respect to a single contract entered into by our subsidiary, Coastal Petroleum NV (CPNV). The report lists Oscar Wyatt as the non-contractual beneficiary of the contract. The report indicates that the payments were made by two other individuals or entities and does not contend that CPNV paid that surcharge. We continue to cooperate with all government investigations into 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. We do not believe that these matters will have a material impact on us.

Rates and Regulatory Matters

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. Subject to refund, the rates became effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG's former full requirements customers under the terms of our FERC approved systemwide capacity allocation proceeding terminated. The FERC accepted a delay in the effective date of the proposed new services and certain other provisions until April 1, 2006. EPNG is continuing settlement discussions with its customers. The outcome of this rate case cannot be predicted with certainty at this time.

Other Contingencies

Iraq Imports. In December 2005, the Ministry of Oil for the State Oil Marketing Organization of Iraq (SOMO) sent an invoice to one of Coastal's subsidiaries with regard to shipments of crude oil that SOMO alleged were purchased and paid for by Coastal in 1990. The invoices request an additional $144 million of payments for such shipments, along with an allegation of an undefined amount of interest. The invoice appears to be associated with cargoes that Coastal had purchased just before the 1990 invasion of Kuwait by Iraq. We are evaluating the invoice and the underlying facts. In addition, we are evaluating our legal defenses, including applicable statute of limitation periods.

Navajo Nation. Nearly 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on lands held in trust by the United States for the benefit of the Navajo Nation. Our rights-of-way, on lands crossing the Navajo Nation expired in October 2005. Under an interim agreement reached in January 2006, the Navajo Nation consented to EPNG's continued use and enjoyment of their existing rights-of-way through the end of 2006. Under the interim agreement, EPNG will make quarterly payments to the Navajo Nation, subject to a two-way adjustment if the parties reach final agreement on a long term right of way agreement prior to the end of 2006. Negotiations on the terms of the long-term agreement are continuing. Although the Navajo Nation has at times demanded more than ten times the $2 million annual fee that existed prior to the execution of the interim agreement, EPNG continues to offer a combination of cash and non-cash consideration, including collaborative projects to benefit the Navajo Nation. In addition, EPNG continues to preserve other legal and regulatory alternatives, which include continuing to pursue our application with the Department of the Interior for renewal of our rights-of-way on Navajo Nation lands. EPNG also continues to press for public policy intervention by Congress in this area. The Energy Policy Act of 2005 commissioned a comprehensive study of energy infrastructure rights-of-way on tribal lands. The study, to be conducted jointly by the Departments of Energy and the Department of Interior must be submitted to Congress by August 2006. It is uncertain whether our negotiation, public policy or litigation efforts will be successful, or if successful, what will be the ultimate cost of obtaining the rights-of-way or whether EPNG will be able to recover these costs in its rate case.

Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil, including our Macae project discussed previously. Our total investment in Brazil was approximately $1.3 billion as of December 31, 2005 (of which $0.9 billion relates to our Power segment and $0.4 billion relates to our Exploration and Production segment). In addition, we also have $225 million of project financing related to Macae which is non-recourse to us. For a further discussion, see Note 14. In a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, the outcome of current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material.

We also own an investment in the Porto Velho power plant. The Porto Velho project is in the process of negotiating certain provisions of its power purchase agreements (PPA) with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant's capacity. The project expects to repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the ongoing contract negotiations do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was approximately $302 million at December 31, 2005.

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, discussed above, cannot be predicted with certainty and there are still uncertainties related to the 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 accruals accordingly, and these adjustments could be material. As of December 31, 2005, we had approximately $574 million accrued, net of related insurance receivables, for outstanding legal and other contingent matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2005, we had accrued approximately $379 million, which has not been reduced by $27 million for amounts paid directly under government sponsored programs. Our accrual includes approximately $368 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $11 million for related environmental legal costs. Of the $379 million accrual, $75 million was reserved for facilities we currently operate, and $304 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 $379 million to approximately $546 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 ($75 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($304 million to $471 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

Sites	December 31, 2005 Expected	High
	(In millions)	
Operating	$ 75	$ 75
Non-operating	265	402
Superfund	39	69
Total	$379	$546

Below is a reconciliation of our accrued liability from January 1, 2005, to December 31, 2005 (in millions):

Balance as of January 1, 2005	$380
Additions/adjustments for remediation activities	65
Payments for remediation activities	(66)
Balance as of December 31, 2005	$379

For 2006, we estimate that our total remediation expenditures will be approximately $76 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $91 million in the aggregate for the years 2006 through 2010. These expenditures primarily relate to compliance with clean air regulations.

Polychlorinated Biphenyls (PCB) Cost Recoveries. Pursuant to a consent order executed by TGP, our subsidiary, in May 1994, with the EPA, TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCBs, and certain other hazardous materials. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its PCB remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of December 31, 2005, TGP had pre-collected PCB costs of approximately $132 million. The pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of December 31, 2005, TGP recorded a regulatory liability of $110 million for the estimated future refund obligations.

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 47 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, 2005, we have estimated our share of the remediation costs at these sites to be between $39 million and $69 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, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons 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 related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Commitments, Purchase Obligations and Other Matters

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 2006 until 2053. As of December 31, 2005, our total commitments under non-cancellable operating leases were approximately $217 million which have not been reduced by minimum sublease rentals of approximately $15 million due in the future under noncancelable subleases. Minimum annual rental commitments under our operating leases at December 31, 2005, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2006	$ 81
2007	71
2008	14
2009	11
2010	7
Thereafter	33
Total	$217

During 2004, we announced that we would consolidate our Houston-based operations into one location. We recorded a charge of $80 million in 2004 as a result of this decision and an additional charge of $27 million in 2005 upon vacating this remaining leased space and signing a termination agreement on the lease. Our remaining obligation under this terminated agreement is included in the table above. Rental expense on our non-terminated lease obligations for the years ended December 31, 2005, 2004, and 2003 was $55 million, $92 million, and $105 million.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnification for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

We record accruals for our guaranty and indemnification arrangements at their fair value when they are issued and subsequently adjust those accruals when we believe it is both probable that we will have to pay amounts under the arrangements and those amounts can be estimated. As of December 31, 2005, we had a liability of $91 million related to our guarantees and indemnification arrangements. These arrangements had a total stated value of $233 million, for which we are indemnified by third parties for $29 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 14.

In addition to the exposures described above, a trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits being paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $380 million associated with our estimated exposure under this matter as of December 31, 2005. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2005, we had firm commitments under transportation and storage capacity contracts of $854 million, commodity purchase commitments of $142 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $562 million.

We also hold cancelable easements or right-of-way arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems. Currently, our obligation under these easements is not material to the results of our operations. However, we are currently negotiating a long-term right-of-way agreement with the Navajo Nation which could result in a significant commitment to us (see Other Contingencies).

17. Retirement Benefits

Overview of Retirement Benefits

Pension Benefits. Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat or Coastal receive the greater of cash balance benefits or transition benefits under the prior plan formulas. We do not anticipate making any contributions to this pension plan in 2006.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We also maintain two other pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. The SERP and the frozen plans together are referred to below as other pension plans. We also participate in several multi-employer pension plans for the benefit of our former employees who were union members. Our contributions to these plans during 2005, 2004 and 2003 were not material. We expect to contribute $5 million to the SERP and $11 million to the frozen plans in 2006.

During 2004, we recognized a $4 million curtailment benefit in our pension plans primarily related to a reduction in the number of employees that participate in our pension plan, which resulted from our various asset sales and employee severance.

Retirement Savings Plan. We maintain a defined contribution plan covering all of our U.S. employees. We match 75 percent of participant basic contributions up to 6 percent of eligible compensation and can make additional discretionary matching contributions. Amounts expensed under this plan were approximately $30 million, $16 million and $14 million for the years ended December 31, 2005, 2004 and 2003.

Other Postretirement Benefits. We provide postretirement medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. We expect to contribute $45 million to our postretirement plans in 2006. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits.

Pension and Other Postretirement Benefits. Below is our projected benefit obligation, accumulated benefit obligation, fair value of plan assets as of September 30, our plan measurement date, and related balance sheet accounts for our pension plans as of December 31:

	Primary Pension Plan		Other Pension Plans	
	2005	2004	2005	2004
	(In millions)			
Projected benefit obligation	$2,059	$1,948	$176	$170
Accumulated benefit obligation	2,041	1,934	176	169
Fair value of plan assets	2,253	2,196	97	93
Accrued benefit liability	—	—	77	74
Prepaid benefit cost	918	960	—	—
Accumulated other comprehensive loss	—	—	75	70

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded pre-tax other comprehensive income (loss) of $(5) million in 2005, $(33) million in 2004 and $18 million in 2003 related to the change in this additional minimum liability.

Change in Projected Benefit Obligation, Plan Assets and Funded Status. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$2,118	$2,091	$ 541	$ 575
Service cost	22	31	1	1
Interest cost	121	121	29	34
Participant contributions	—	—	34	27
Settlements, curtailments and special termination benefits	—	(3)	—	—
Actuarial loss (gain)	178[(1)]	76[(1)]	(5)	(20)
Benefits paid	(203)	(198)	(73)	(76)
Other	(1)	—	—	—
Projected benefit obligation at end of period	$2,235	$2,118	$ 527	$ 541
Change in plan assets:				
Fair value of plan assets at beginning of period	$2,289	$2,197	$ 220	$ 196
Actual return on plan assets	255	277	20	12
Employer contributions	9	12	50	61
Participant contributions	—	—	34	27
Benefits paid	(203)	(198)	(73)	(76)
Administrative expenses	—	1	—	—
Fair value of plan assets at end of period	$2,350	$2,289	$ 251	$ 220

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(In millions)			
Reconciliation of funded status:				
Fair value of plan assets at September 30	$2,350	$2,289	$ 251	$ 220
Less: Projected benefit obligation at end of period	2,235	2,118	527	541
Funded status at September 30	115	171	(276)	(321)
Fourth quarter contributions and income	2	2	11	13
Unrecognized net actuarial loss[2]	814	800	20	32
Unrecognized net transition obligation	—	—	—	8
Unrecognized prior service cost	(13)	(17)	(5)	(6)
Prepaid (accrued) benefit cost at December 31	$ 918	$ 956	$(250)	$(274)

(1) Increase is due primarily to changes in our discount rate and mortality assumptions in 2005 and 2004.

(2) We recognize the difference between our actual return on plan assets and our expected return over a three year period. Our deferred actuarial gains and losses are recognized only to the extent that all of our remaining unrecognized actual gains and loses exceed the greater of 10 percent of our projected benefit obligations or market related value of plan assets.

The portion of our other postretirement benefit obligation included in current liabilities was $35 million and $38 million as of December 31, 2005 and 2004.

Expected Payment of Future Benefits. As of December 31, 2005, we expect the following payments under our plans:

Year Ending December 31,	Pension Benefits	Other Postretirement Benefits[1]
	(In millions)	
2006	$ 167	$ 49
2007	168	47
2008	167	46
2009	167	45
2010	166	44
2011-2015	815	197
Total	$1,650	$428

(1) Includes a reduction of $3 million for the years 2006 through 2008 and $4 million for each year thereafter for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

Components of Net Benefit Cost (Income). For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
	(In millions)					
Service cost	$ 22	$ 31	$ 36	$ 1	$ 1	$ 1
Interest cost	121	121	134	29	34	35
Expected return on plan assets	(168)	(187)	(227)	(12)	(11)	(9)
Amortization of net actuarial loss	69	47	7	—	4	1
Amortization of transition obligation	—	—	(1)	8	8	8
Amortization of prior service cost[1]	(2)	(3)	(3)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	—	(4)	11	—	—	(6)
Other	7	—	—	—	—	—
Net benefit cost (income)	$ 49	$ 5	$ (43)	$ 25	$35	$29

(1) As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

Actuarial Assumptions and Sensitivity Analysis. 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 costs of our pension and other postretirement plans for 2005, 2004 and 2003:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	5.50	5.75		5.25	5.75	
Rate of compensation increase	4.00	4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	5.75	6.00	6.75	5.75	6.00	6.75
Expected return on plan assets[(1)]	8.00	8.50	8.80	7.50	7.50	7.50
Rate of compensation increase	4.00	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 26 percent to 27 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.

Actuarial estimates for our other postretirement benefit plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.9 percent, gradually decreasing to 5.0 percent by the year 2015. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

	2005	2004
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	20	19
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(18)	(18)

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 2005	Actual 2004	Target	Actual 2005	Actual 2004
		(Percent)			(Percent)	
Equity securities[(1)]	60	65	62	65	61	60
Debt securities	40	34	37	35	32	33
Other	—	1	1	—	7	7
Total	100	100	100	100	100	100

(1) During the third quarter of 2005, we liquidated all of the El Paso common stock included in plan assets. At September 30, 2004, actuals for our pension plans include $42 million (1.8 percent of total assets) of our common stock.

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.

Other Matters. During the fourth quarter of 2005, we recorded an increase to our legal reserves of approximately $350 million associated with a closed group of retirees of the Case Corporation increasing our total liability to $380 million at December 31, 2005. A trial court ruled, which was upheld on appeal, that we are required to indemnify Case for benefits paid to these retirees. We estimated our liability under this ruling utilizing actuarial methods similar to those used in estimating our obligations associated with our other postretirement benefit plans; however, these legal reserves are not included in the disclosures related to our pension and other postretirement benefits above. For a further discussion of this matter, see Note 16.

18. Capital Stock

Common Stock

In 2003 and 2004, we issued 26.4 million shares to satisfy our obligations under the Western Energy Settlement. In December 2003, we completed a tender offer to exchange approximately 53 percent of our total 9.0% equity security units outstanding for $59 million in cash, and issued approximately 15.2 million shares of our common stock with a total market value of $119 million. In August 2005, we issued approximately 13.6 million shares of common stock to the remaining holders of $272 million of notes which originally formed a portion of our equity security units in settlement of their commitment to purchase the shares.

Convertible Perpetual Preferred Stock

In April 2005, we issued $750 million of convertible perpetual preferred stock. Cash dividends on the preferred stock are paid quarterly at the rate of 4.99% per annum if declared by our Board of Directors. Unpaid dividends accumulate at 4.99% until paid. Each share of the preferred stock is convertible at the holder's option, at any time, subject to adjustment, into 76.7754 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately $13.03 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or adjustments to the current rate of dividends on our common stock. We will be able to cause the preferred stock to be converted into common stock after five years if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds of $723 million from the issuance of the preferred stock, together with cash on hand, was used to prepay our Western Energy Settlement of approximately $442 million in April 2005, and to pay the redemption price (an aggregate of $300 million plus accrued dividends of $3 million) of the 6 million outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, EPTP, in May 2005.

Dividends

The table below shows the amount of dividends paid and declared (in millions, except per share amounts).

	Common Stock ($0.04/share)	Convertible Preferred Stock (4.99%/year)
Amount paid in 2005	$104	$17
Amount paid in January 2006	$25	$10
Declared in 2006:		
Date of declaration	February 14, 2006	February 14, 2006
Date payable	April 3, 2006	April 3, 2006
Payable to shareholders on record	March 3, 2006	March 15, 2006

Dividends on our common stock are treated as reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common and preferred stock in 2005 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set aside for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restriction on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If our fixed charge ratio were to exceed the permitted maximum level, our ability to pay additional dividends would be restricted.

19. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using APB No. 25 and its related interpretations. Under our stock-based compensation plans, we may issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. In addition, we may also issue shares under our employee stock purchase plan or issue deferred shares of common stock to our non-employee directors.

We are authorized to grant awards of approximately 42.5 million shares of our common stock under our current plans, which includes 35 million shares under our employee plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At December 31, 2005, approximately 40 million shares remain available for grant under our current plans. In addition, we have approximately 28 million shares of stock option awards outstanding which were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2005, 2004 and 2003. Our stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. Prior to 2004, we also granted options to non-employee members of the Board of Directors at fair market value on the grant date that were exercisable immediately. A summary of our stock option transactions, stock options outstanding and stock options exercisable as of December 31 is presented below:

	Stock Options					
	2005		2004		2003	
	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	33,923,578	$42.73	36,245,014	$47.90	43,208,374	$49.16
Granted	4,254,270	$10.74	4,842,453	$ 7.16	1,180,041	$ 7.29
Exercised	(219,244)	$ 7.31	(3,193)	$ 7.64	—	—
Converted[1]	—	—	(11,333)	$42.99	(871,250)	$42.00
Forfeited or canceled	(9,875,119)	$45.78	(7,149,363)	$44.75	(7,272,151)	$49.53
Outstanding at end of year	28,083,485	$37.12	33,923,578	$42.73	36,245,014	$47.90
Exercisable at end of year	20,792,538	$46.96	28,455,056	$49.45	28,703,151	$46.04

(1) Includes the conversion of stock options into common stock and cash at no cost to employees based upon achievement of certain performance targets and lapse of time. These options had an original stated exercise price of approximately $43 per share and $42 per share in 2004 and 2003.

The following table summarizes the range of exercise prices and the weighted-average remaining contractual life of options outstanding and the range of exercise prices for the options exercisable at December 31, 2005.

Range of Exercise Prices	Options Outstanding: Number Outstanding	Options Outstanding: Weighted Average Remaining Years of Contractual Life	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Number Exercisable	Options Exercisable: Weighted Average Exercise Price
$ 0.00 - $14.29	8,866,680	8.4	$ 8.74	1,575,733	$ 7.24
$14.30 - $28.59	2,292,259	1.3	$21.76	2,292,259	$21.76
$28.60 - $42.88	4,740,576	2.9	$39.79	4,740,576	$39.79
$42.89 - $57.18	4,405,272	3.6	$46.91	4,405,272	$46.91
$57.19 - $70.63	7,778,698	4.1	$66.82	7,778,698	$66.82
	28,083,485	5.0	$37.12	20,792,538	$46.96

SFAS No. 123 Assumptions

The fair value of each stock option granted was estimated on the date of grant using a separate Black-Scholes option-pricing calculation for each grant and was used to estimate the pro forma compensation expense in Note 1. Listed below is the weighted average of each assumption based on grants in each fiscal year:

Assumption:	2005	2004	2003
Expected Term in Years	4.82	5.35	6.19
Expected Volatility	42%	45%	52%
Expected Dividends	1.5%	2.1%	2.2%
Risk-Free Interest Rate	3.7%	3.7%	3.4%

These assumptions yielded a weighted average grant date fair value of options granted of $3.88 per share in 2005, $2.69 per share in 2004 and $3.21 per share in 2003.

Restricted Stock

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our officers and employees, which typically vest over three years from the date of grant. These shares carry voting and dividend rights, however, sale or transfer of the shares is restricted until they vest. We currently have outstanding and grant only time-based restricted share awards. Historically, we also granted performance-based restricted share awards; however, these shares have been fully vested or were forfeited prior to the end of 2005. The fair value of our time-based restricted shares is determined on the grant date, recorded as unamortized compensation as a component of stockholders' equity on our balance sheet and amortized to compensation expense over the vesting period.

During 2005, 2004 and 2003 we granted 2.1 million, 3.1 million and 0.4 million shares of restricted stock awards with a weighted average grant date fair value of $10.78, $8.63 and $7.46 per share, respectively. We recognized compensation expense of $18 million, $23 million and $60 million during 2005, 2004 and 2003 related to the vesting of our restricted stock grants. At December 31, 2005, we had 4 million shares of time-based restricted stock outstanding and $17 million of unamortized compensation on our balance sheet that will be charged to compensation expense over the remaining vesting period.

Employee Stock Purchase Program

In July 2005, we reinstated our employee stock purchase plan under Section 423 of the Internal Revenue Code. The amended and restated plan allows participating employees the right to purchase our common stock on a quarterly basis at 95 percent of the market price on the last trading day of each month. At December 31, 2005, approximately 3 million shares remain available for issuance under this plan.

20. Business Segment Information

Our business consists of our Pipelines, Exploration and Production, Marketing and Trading, 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, a telecommunications business, and various other contracts and assets, all of which are immaterial. These other assets and contracts relate to assets or businesses sold including financial services, LNG and other items.

During 2005, we reclassified our south Louisiana gathering and processing assets, which were part of our Field Services segment, and the international power operations at our Nejapa, CEBU and East Asia Utilities power plants as discontinued operations. Our operating results for all periods reflect these operations as discontinued.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. We conduct our activities primarily through eight wholly owned and four partially owned interstate transmission systems along with five underground natural gas storage entities and an LNG terminalling facility.

Our Exploration and Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States and Brazil.

Our Marketing and Trading segment's operations focus on marketing and managing the price risk associated with our natural gas and oil production as well as the management of our remaining trading portfolio.

Our Power segment primarily consists 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 ongoing focus within the Power segment will be to manage the risks associated with our remaining assets in Brazil.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets. We have disposed of substantially all of the assets in this segment. Our remaining assets were transferred to our Exploration and Production segment during the first quarter of 2006.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2005, 2004 and 2003.

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

	2005	2004	2003
		(In millions)	
Segment EBIT	$ 919	$ 1,034	$ 1,605
Corporate and other	(521)	(217)	(852)
Interest and debt expense	(1,380)	(1,607)	(1,790)
Distributions on preferred interests of consolidated subsidiaries	(9)	(25)	(52)
Income taxes	289	(14)	484
Loss from continuing operations	$ (702)	$ (829)	$ (605)

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

	As of or for the Year Ended December 31, 2005						
	Segments						
	Pipelines	Exploration and Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
Revenue from external customers							
Domestic	$ 2,706	$ 466[2]	$ 411	$ 71	$ 96	$ 84	$ 3,834
Foreign	7	54[2]	3	47	—	—	111
Intersegment revenue	70	1,267[2]	(1,210)	11	27	(93)	72[3]
Operation and maintenance	908	383	54	140	27	571	2,083
Depreciation, depletion, and amortization	437	612	4	23	3	42	1,121
(Gain) loss on long-lived assets	35	—	—	366	10	(4)	407
Earnings (losses) from unconsolidated affiliates	161	19	—	(139)	301	—	342
EBIT	1,226	696	(837)	(451)	285	(521)	398
Discontinued operations, net of income taxes	—	9	—	(126)	251	(34)	100
Assets of continuing operations[4]							
Domestic	16,421	5,215	3,786	70	99	4,087	29,678
Foreign[5]	26	355	33	1,653	—	57	2,124
Capital expenditures, capital investments and advances to unconsolidated affiliates, net[6]	908	1,851	—	6	8	14	2,787
Total investments in unconsolidated affiliates	1,042	761	—	670	—	—	2,473

(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 $91 million and an operation and maintenance expense elimination of $2 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. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $36 million (see Note 3).

(5) Of total foreign assets, approximately $672 million relates to property, plant and equipment and approximately $1.0 billion relates to investments in and advances to unconsolidated affiliates.

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

	As of or for the Year Ended December 31, 2004						
	Segments						
	Pipelines	Exploration and Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
	(In millions)						
Revenue from external customers							
Domestic	$ 2,554	$ 535[2]	$ 697	$ 241	$ 938	$ 132	$ 5,097
Foreign	9	26[2]	2	318	—	15	370
Intersegment revenue	88	1,174[2]	(1,207)	94	159	(236)	72[3]
Operation and maintenance	777	365	53	274	74	201	1,744
Depreciation, depletion, and amortization	410	548	13	38	8	51	1,068
(Gain) loss on long-lived assets	(1)	8	—	569	507	(6)	1,077
Earnings (losses) from unconsolidated affiliates	173	4	—	(249)	618	—	546
EBIT	1,331	734	(539)	(576)	84	(217)	817
Discontinued operations, net of income taxes	—	(36)	—	(24)	20	(78)	(118)
Assets of continuing operations[4]							
Domestic	15,930	3,714	2,372	982	518	4,424	27,940
Foreign[5]	58	366	32	2,380	—	96	2,932
Capital expenditures, capital investments and advances to unconsolidated affiliates, net[6]	1,047	728	—	27	(15)	10	1,797
Total investments in unconsolidated affiliates	1,032	6	—	1,225	305	6	2,574

(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 $236 million and an operation and maintenance expense elimination of $25 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. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $511 million (see Note 3).

(5) Of total foreign assets, approximately $1.1 billion relates to property, plant and equipment and approximately $1.5 billion relates to investments in and advances to unconsolidated affiliates.

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

	As of or for the Year Ended December 31, 2003						
	Segments						
	Pipelines	Exploration and Production	Marketing and Trading	Power	Field Services	Corporate(1)	Total
	(In millions)						
Revenue from external customers							
Domestic	$ 2,527	$ 201(2)	$ 1,430	$ 515	$ 907	$ 113	$ 5,693
Foreign	2	—	—	394	2	13	411
Intersegment revenue	118	1,940(2)	(2,065)	145	374	(277)	235(3)
Operation and maintenance	847	342	158	472	85	95	1,999
Depreciation, depletion, and amortization	386	576	25	76	27	67	1,157
(Gain) loss on long-lived assets	(10)	5	(3)	185	173	510	860
Earnings (losses) from unconsolidated affiliates	119	13	—	(91)	329	(7)	363
EBIT	1,234	1,091	(809)	(40)	129	(852)	753
Discontinued operations, net of income taxes	—	24	—	8	2	(1,303)	(1,269)
Assets of continuing operations(4)							
Domestic	15,659	3,459	2,661	3,897	1,870	3,916	31,462
Foreign(5)	27	308	5	2,824	—	141	3,305
Capital expenditures and investments in and advances to unconsolidated affiliates, net(6)	837	1,300	(1)	1,081	(25)	89	3,281
Total investments in unconsolidated affiliates	1,018	79	—	1,626	655	5	3,383

(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 $338 million and an operation and maintenance expense elimination of $59 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. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $2.2 billion.

(5) Of total foreign assets, approximately $1.2 billion relates to property, plant and equipment, and approximately $1.7 billion relates to investments in and advances to unconsolidated affiliates.

(6) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital. Our Power segment includes approximately $1 billion to acquire remaining interest in Chaparral and Gemstone (see Note 2).

21. Investments in, Earnings from and Transactions with Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. Our income statement typically reflects (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments and other adjustments recorded by us.

Our investment balance differs from the underlying net equity in our investments due primarily to purchase price adjustments or impairment charges recorded by us. As of December 31, 2005, our investment balance exceeded the net equity in the underlying net assets of these investments by $443 million due to these items. The largest of our purchase price adjustments is related to our investment in Four Star which we amortize over the life of its proved reserves. Our investment balance at December 31, 2004 was lower than the underlying net assets of our investments by $305 million. Our net ownership interest, investments in and earnings (losses) from our consolidated affiliates are as follows as of and for the years ended December 31:

	Net Ownership Interest		Investment		Earnings (Losses) from Unconsolidated Affiliates		
	2005	2004	2005	2004	2005	2004	2003
	(Percent)		(In millions)		(In millions)		
Domestic:							
Four Star[1]	43	—	$ 754	$ —	$ 19	$ —	$ —
Citrus	50	50	596	589	66	65	43
Enterprise Products Partners[2]	—	—	—	257	183	6	—
GulfTerra Energy Partners[2]	—	—	—	—	—	601	419
Midland Cogeneration Venture	44	44	—	191	(162)	(171)	29
Great Lakes Gas Transmission	50	50	300	316	59	65	57
Javelina[2]	—	40	—	45	121	15	(2)
Milford[2]	—	—	—	—	—	(1)	(88)
Chaparral Investors[2]	—	—	—	—	—	—	(207)
Other Domestic Investments	various	various	55	47	19	25	(36)
Total domestic			1,705	1,445	305	605	215
Foreign:							
Korea Independent Energy Corporation[2]	—	50	—	176	127	22	29
Araucaria Power[3]	60	60	187	186	—	—	—
EGE Itabo[4]	25	25	24	88	(58)	1	1
Bolivia to Brazil Pipeline	8	8	96	86	20	24	17
EGE Fortuna[4]	25	25	68	65	2	6	3
Aguaytia Energy[4]	24	24	23	39	(11)	(5)	4
San Fernando Pipeline	50	50	53	46	14	13	5
Habibullah Power[4][5]	50	50	16	20	(13)	(46)	(3)
Manaus[6]	100	—	65	—	10	—	—
Rio Negro[6]	100	—	49	—	9	—	—
Saba Power Company[4]	94	94	—	7	(7)	(51)	4
Other Foreign Investments[5]	various	various	187	416	(56)	(23)	88
Total foreign			768	1,129	37	(59)	148
Total investments in unconsolidated affiliates			$2,473	$2,574			
Total earnings from unconsolidated affiliates					$ 342	$ 546	$ 363

(1) We acquired our interest in Four Star in 2005 in connection with our acquisition of Medicine Bow.

(2) We sold our interest in Enterprise, Javelina and Korea Independent Energy Corporation in 2005 and GulfTerra in 2004. We also transferred our interest in Milford and consolidated Chaparral Investors during 2003.

(3) We signed a letter of intent in February 2006 to sell our interest in this power facility.

(4) We sold our interest in Aguaytia Energy in the first quarter of 2006. We have received approval from our Board of Directors to sell our interest in the other investments, which are targeted to close in the first half of 2006.

(5) As of December 31, 2005 and 2004, we also had outstanding advances and receivables of $37 million and $64 million related to our investment in Habibullah Power. We also had other outstanding advances and receivables of $348 million and $320 million related to our other foreign investments as of December 31, 2005 and 2004, of which $331 million and $307 million are related to our investment in Porto Velho.

(6) While we continue to have 100 percent ownership, we deconsolidated these investments in January 2005, upon entering into an agreement that will transfer ownership of these plants to the power purchaser in January 2008.

Impairment charges and gains and losses on sales of equity investments are included in earnings from unconsolidated affiliates. During 2005, 2004 and 2003, our impairments, gains and losses were primarily a result of our decision to sell a number of these investments, but we also had several investments that experienced declines in their fair value due to changes in economics of the investments' underlying contracts, or the markets they serve. These gains and losses consisted of the following:

Investment or Group	2005	2004	2003
		(In millions)	
Midland Cogeneration Venture[1]	$(162)	$(161)	$ —
Asia power investments	(64)	(182)	(1)
Central and South American power investments	(89)	—	24
Chaparral Investors	—	—	(207)
Domestic power plants held for sale, sold or transferred	—	(44)	(163)
Dauphin Island Gathering/Mobile Bay Processing	—	—	(86)
Enterprise/GulfTerra[2]	183	507	266
Javelina	111	—	—
KIECO	108	—	—
Other	4	4	(9)
	$ 91	$ 124	$(176)

(1) Represents an impairment of our investment in 2004 and our proportionate share of losses from our investment in MCV in 2005, primarily based on MCV's impairment of the plant assets.

(2) See further discussion of these sales below.

Below is summarized financial information of our proportionate share of the operating results and financial position of our unconsolidated affiliates, including those in which we hold greater than a 50 percent interest.

	Year Ended December 31,		
	2005	2004	2003
		(In millions)	
Operating results data:			
Operating revenues	$1,611	$2,211	$3,360
Operating expenses	1,468	1,485	2,309
Income (loss) from continuing operations	(123)	388	519
Net income (loss)[1]	(123)	388	520
Financial position data:[2]			
Current assets	$1,002	$1,248	
Non-current assets	4,016	5,265	
Short-term debt	250	250	
Other current liabilities	478	488	
Long-term debt	1,381	2,044	
Other non-current liabilities	786	779	
Minority interest	84	73	
Redeemable preferred stock	9	—	
Equity in net assets	2,030	2,879	

(1) Includes net income of $15 million, $7 million and $119 million in 2005, 2004 and 2003, related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

(2) Includes total assets of $485 million and $593 million as of December 31, 2005 and 2004 related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

We received distributions and dividends of $279 million and $358 million in 2005 and 2004, which includes less than $1 million and $23 million of returns of capital, from our investments.

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

	2005	2004	2003
		(In millions)	
Operating revenue[1]	$117	$199	$216
Other revenue — management fees	—	3	13
Cost of sales	15	101	105
Reimbursement for operating expenses[1]	5	95	139
Other income	9	8	10
Interest income	47	44	36
Interest expense	—	—	2

(1) Decrease in 2005 is due primarily to the sale of GulfTerra during 2004. See further discussion below.

GulfTerra and Enterprise

During 2003 and 2004, we owned a general partnership interest and common and preference units in GulfTerra Energy Partners, a limited partnership that held a variety of natural gas gathering, treating and processing assets. During 2004, GulfTerra merged with Enterprise Products Partners. Through a series of transactions in 2003, 2004 and 2005, we disposed of our interests in GulfTerra and Enterprise.

During 2003 and 2004, our Field Services segment managed GulfTerra's daily operations and performed all of their administrative and operational activities through a series of agreements. We also had a number of other transactions with GulfTerra and Enterprise, including sales under natural gas transportation contracts and the sale of several of our natural gas gathering, treating and processing assets to GulfTerra in previous years. The following table summarizes the income statement impacts of our transactions with GulfTerra and Enterprise and the sale of our interests in those entities for the years ended December 31:

	2005	2004	2003
		(In millions)	
Operating revenue	$ —	$ 28	$ 33
Operating expenses	—	113	114
Reimbursements	—	(71)	(91)
Earnings from unconsolidated affiliates			
Proportionate share of earnings and other income	—	100	153
Gains on sales of investments	183	507	266

Matters that Could Impact Our Investments

Investments in Power Facilities. We have interests in a number of equity and cost basis investments that are considered variable interests under FIN No. 46(R). As of December 31, 2005, these entities consisted primarily of 17 equity and cost investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 4,240 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 investment in and advances to the entities ($564 million as of December 31, 2005) and our guarantees and other agreements associated with these entities (a maximum of $87 million as of December 31, 2005).

We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. Berkshire's lenders have asserted that Berkshire is in default on its loan agreement and on February 9, 2006, the lenders declared all obligations outstanding under the loan agreement to be immediately due and payable in full. This obligation is non-recourse to El Paso. We have previously fully impaired the value of this investment. However, we supply natural gas to Berkshire under a fuel management agreement. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of the delayed payments based on Berkshire's inability to generate adequate cash flows related to this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future fuel deliveries are not paid under this agreement because of Berkshire's inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders. We are in discussions with the lenders and other owners of the project to transfer or terminate our interest in this project.

We supply gas to power plants that we partially own, including the Midland Cogeneration Venture (MCV) and Berkshire power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these contracts to the extent of our ownership interest. However, should we sell our interests in these plants, we would record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $146 million as of December 31, 2005. We also have issued letters of credit and margin deposits to MCV for approximately $386 million and $44 million as of December 31, 2005, securing our obligation under the gas supply contracts.

Investment in Bolivia. We own an eight percent interest in the Bolivia to Brazil pipeline in which we have approximately $108 million of exposure, including guarantees, as of December 31, 2005. During 2005, political disputes in Bolivia related to pressure to nationalize the energy industry led to the resignation of the country's president and the election of a new president. Recent changes in Bolivian law have also increased the combined rate of production taxes and royalties to 50 percent and required that existing exploration contracts be renegotiated. Actions by the new government in Bolivia could potentially lead to a disruption or cessation of the supply of gas from that country and impact the payments that our investment receives from Petrobras. We continue to monitor the political situation in Bolivia and as new information becomes available or future material developments arise, it is possible that a future impairment of our investment may occur.

Citrus Corporation. Citrus Trading Corporation (CTC), a subsidiary of Citrus Corp. (Citrus), in which we own a 50 percent equity interest, has filed suit against Duke Energy LNG Sales, Inc. (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. CTC filed a motion for partial summary judgment, requesting that the court find that Duke failed to give proper notice of default to CTC regarding its alleged failure to maintain the letter of credit. Duke has filed an amended counter claim in federal court joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC has filed an answer to Duke's motion. In August 2005, the federal district court issued an order denying both motions for summary judgment, asserting that the ambiguity in the contract and the performance of the parties created issues of fact that precluded summary judgment on either side. CTC has filed additional motions for partial summary judgment, requesting that the court find that Duke improperly asserted force majeure due to its alleged loss of gas supply and that Duke is in error in asserting that CTC breached contractual provisions that imposed resale restrictions and credit maintenance obligations. An unfavorable outcome on this matter could impact the value of our investment in Citrus. However, we do not expect the ultimate resolution of this matter to have a material adverse effect on us.

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

	Quarters Ended				
	March 31	**June 30**	**September 30**	**December 31**	**Total**
	(In millions, except per common share amounts)				
2005					
Operating revenues	$ 1,108	$ 1,184	$ 768	$ 957	$ 4,017
Loss on long-lived assets	7	276	3	121	407
Operating income (loss)	243	89	(158)	(361)	(187)
Earnings (losses) from unconsolidated affiliates	190	(19)	14	157	342
Income (loss) from continuing operations	115	(212)	(322)	(283)	(702)
Discontinued operations, net of income taxes[1]	(9)	(26)	10	125	100
Net income (loss)	106	(238)	(312)	(162)	(606)
Net income (loss) available to common stockholders	106	(246)	(321)	(172)	(633)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	0.18	(0.34)	(0.51)	(0.45)	(1.13)
Net income (loss)	0.17	(0.38)	(0.50)	(0.26)	(0.98)

	Quarters Ended				
	March 31	**June 30**	**September 30**	**December 31**	**Total**
	(In millions, except per common share amounts)				
2004					
Operating revenues	$ 1,472	$ 1,443	$ 1,349	$ 1,275	$ 5,539
Loss on long-lived assets	238	17	582	240	1,077
Operating income (loss)	180	361	(368)	9	182
Earnings (losses) from unconsolidated affiliates	87	98	617	(256)	546
Income (loss) from continuing operations	(126)	28	(205)	(526)	(829)
Discontinued operations, net of income taxes[1]	(70)	(23)	(9)	(16)	(118)
Net income (loss)	(196)	5	(214)	(542)	(947)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	(0.20)	0.04	(0.32)	(0.82)	(1.30)
Net income (loss)	(0.31)	0.01	(0.33)	(0.85)	(1.48)

[1] Our petroleum markets operations, our Canadian and certain other international natural gas and oil production operations, our south Louisiana gathering and processing operations, and our consolidated international power operations in Central America and Asia are classified as discontinued operations (See Note 3 for further discussion).

Supplemental Natural Gas and Oil Operations (Unaudited)

Our Exploration and Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States and Brazil.

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

	United States	Brazil	Worldwide
2005			
Natural gas and oil properties:			
Costs subject to amortization	$14,874	$371	$15,245
Costs not subject to amortization	384	107	491
	15,258	478	15,736
Less accumulated depreciation, depletion and amortization	11,021	183	11,204
Net capitalized costs	$ 4,237	$295	$ 4,532
FAS 143 abandonment liability	$ 186	$ 4	$ 190
2004			
Natural gas and oil properties:			
Costs subject to amortization	$14,211	$337	$14,548
Costs not subject to amortization	308	112	420
	14,519	449	14,968
Less accumulated depreciation, depletion and amortization	11,130	138	11,268
Net capitalized costs	$ 3,389	$311	$ 3,700
FAS143 abandonment liability	$ 252	$ 4	$ 256

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

	United States	Brazil	Worldwide
2005			
Property acquisition costs			
Proved properties	$ 643	$ 8	$ 651
Unproved properties	143	—	143
Exploration costs	143	15	158
Development costs	503	6	509
Costs expended in 2005	1,432	29	1,461
Asset retirement obligation costs	1	—	1
Total costs incurred(1)	$1,433	$ 29	$1,462
Unconsolidated investment in Four Star(1)	$ 769	$ —	$ 769
2004			
Property acquisition costs			
Proved properties	$ 33	$ 69	$ 102
Unproved properties	32	3	35
Exploration costs	185	25	210
Development costs	395	1	396
Costs expended in 2004	645	98	743
Asset retirement obligation costs	30	3	33
Total costs incurred	$ 675	$101	$ 776

	United States	Brazil	Worldwide
2003			
Property acquisition costs			
Proved properties	$ 10	$ —	$ 10
Unproved properties	35	4	39
Exploration costs	467	95	562
Development costs	668	—	668
Costs expended in 2003	1,180	99	1,279
Asset retirement obligation costs[(2)]	124	—	124
Total costs incurred	$1,304	$ 99	$1,403

(1) Includes $179 million of deferred income tax adjustments related to the acquisition of full-cost pool properties and $217 million related to the acquisition of our unconsolidated investment in Four Star.

(2) Includes an increase to our property, plant and equipment of approximately $114 million in 2003 associated with our adoption of Statement of Financial Accounting Standard No. 143.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $47 million, $44 million, and $58 million and capitalized interest of $30 million, $22 million and $19 million for the years ended December 31, 2005, 2004 and 2003.

In our January 1, 2006 reserve report, the amounts estimated to be spent in 2006, 2007 and 2008 to develop our worldwide proved undeveloped reserves are $318 million, $459 million and $221 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2005, pending determination of proved reserves (in millions):

	Cumulative Balance	Costs Excluded for Years Ended December 31			Cumulative Balance
	December 31, 2005	2005	2004	2003	December 31, 2002
Worldwide[(1)(2)]					
Acquisition	$358	$221	$52	$ 26	$ 59
Exploration	132	29	13	29	61
Development	1	—	—	—	1
	$491	$250	$65	$ 55	$121

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

(2) Includes capitalized interest of $19 million, $7 million, and less than $1 million for the years ended December 31, 2005, 2004, and 2003.

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 2006 through 2008. Our total amortization expense per Mcfe for the United States was $2.25, $1.84, and $1.40 in 2005, 2004, and 2003 and $2.33 and $2.02 for Brazil in 2005 and 2004. We had no production in Brazil during 2003. Included in our worldwide depreciation, depletion and amortization expense is accretion expense of $0.10/Mcfe, $0.08/Mcfe and $0.06/Mcfe for 2005, 2004 and 2003 for the United States and $0.01/Mcfe for Brazil in 2005 and 2004, attributable to SFAS No. 143, which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil, and condensate, and changes in these reserves at December 31, 2005 are presented below. 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 92 percent of our properties. Based on the amount of proved reserves determined by Ryder Scott, we believe these reported reserve amounts are reasonable. 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 our Board of Directors. The tables below exclude our Power segment's equity interest in in proved reserves in Indonesia and Peru. Our Power segment has completed or expects to complete these sales in 2006. Combined proved reserve balances for these interests were 162,254 MMcf of natural gas and 2,058 MBbls of oil, condensate and NGL for total natural gas equivalents of 174,600 MMcfe, all net to our ownership interests.

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)
	United States(1)	Brazil	Worldwide	United States(1)	Brazil	Worldwide	United States(1)(3)
Consolidated							
Net proved developed and undeveloped reserves							
January 1, 2003	2,488	—	2,488	38,354	—	38,354	21,607
Revisions of previous estimates	(24)	—	(24)	895	—	895	(2,717)
Extensions, discoveries and other	405	—	405	5,000	20,543	25,543	1,795
Purchases of reserves in place	2	—	2	5	—	5	27
Sales of reserves in place	(471)	—	(471)	(4,328)	—	(4,328)	(504)
Production	(339)	—	(339)	(7,555)	—	(7,555)	(4,223)
December 31, 2003	2,061	—	2,061	32,371	20,543	52,914	15,985
Revisions of previous estimates	(172)	—	(172)	(999)	252	(747)	724
Extensions, discoveries and other	79	38	117	2,214	1,848	4,062	58
Purchases of reserves in place	15	38	53	—	1,848	1,848	—
Sales of reserves in place	(21)	—	(21)	(1,276)	—	(1,276)	(47)
Production	(238)	(7)	(245)	(4,979)	(320)	(5,299)	(3,519)
December 31, 2004	1,724	69	1,793	27,331	24,171	51,502	13,201
Revisions of previous estimates	(43)	(2)	(45)	260	7,927	8,187	1,148
Extensions, discoveries and other	183	5	188	8,145	772	8,917	169
Purchases of reserves in place	192	—	192	13,338	—	13,338	772
Sales of reserves in place	(18)	—	(18)	(969)	—	(969)	(89)
Production	(207)	(16)	(223)	(4,877)	(620)	(5,497)	(2,639)
December 31, 2005	1,831	56	1,887	43,228	32,250	75,478	12,562
Proved developed reserves							
December 31, 2003	1,428	—	1,428	22,821	—	22,821	14,088
December 31, 2004	1,287	54	1,341	19,641	2,613	22,254	11,943
December 31, 2005	1,404	27	1,431	28,581	1,144	29,725	11,010
Unconsolidated investment in Four Star(2)							
December 31, 2005							
Net proved developed and undeveloped reserves	193	—	193	3,349	—	3,349	6,668
Proved developed reserves	158	—	158	3,266	—	3,266	5,399

(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) Our unconsolidated share of Four Star's proved reserves has been estimated based on an evaluation of those reserves by El Paso's internal reservoir engineers, and not by engineers of Four Star. An independent reservoir engineering firm, Ryder Scott, which was engaged by us, prepared an estimate on 86 percent of Four Star's proved reserves. Based on the amount of Four Star's proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable.

(3) All of our NGL reserves are in the United States.

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, 2005.

We maintain an agreement with a subsidiary of Nabors Industries in which we sold interests in 23 wells. As the wells were developed, Nabors paid 20 percent of the drilling and development costs in exchange for 20 percent of the net profits of the wells sold. As each well commenced, Nabors received an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 20 percent of the aggregate net profits of all wells until they recover 117.5 percent of their aggregate investment. Upon recovery, the net profits interest converts to a proportionately reduced 2 percent overriding royalty interest in the wells for the remainder of the well's productive life. We do not guarantee a return or the recovery of Nabors' costs.

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

	United States	Brazil	Worldwide
2005			
Net Revenues			
Sales to external customers	$ 431	$ 62	$ 493
Affiliated sales	1,256	(9)	1,247
Total	1,687	53	1,740
Production costs(1)	(253)	(8)	(261)
Depreciation, depletion and amortization	(567)	(45)	(612)
	867	—	867
Income tax expense	(309)	—	(309)
Results of operations from producing activities	$ 558	$ —	$ 558
Equity earnings from unconsolidated investment in Four Star	$ 19	$ —	$ 19
2004			
Net Revenues			
Sales to external customers	$ 500	$ 26	$ 526
Affiliated sales	1,155	—	1,155
Total	1,655	26	1,681
Production costs(1)	(210)	—	(210)
Depreciation, depletion and amortization	(530)	(18)	(548)
	915	8	923
Income tax expense	(333)	(3)	(336)
Results of operations from producing activities	$ 582	$ 5	$ 587

	United States	Brazil	Worldwide
2003			
Net Revenues			
Sales to external customers	$ 147	$ —	$ 147
Affiliated sales	1,912	—	1,912
Total	2,059	—	2,059
Production costs[1]	(229)	—	(229)
Depreciation, depletion and amortization	(576)	—	(576)
Ceiling test charges	—	(5)	(5)
	1,254	(5)	1,249
Income tax (expense) benefit	(449)	2	(447)
Results of operations from producing activities	$ 805	$ (3)	$ 802

[1] Production cost includes lease operating costs and production related taxes, including ad valorem and severance taxes.

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

	United States	Brazil	Worldwide
2005			
Future cash inflows[1]	$18,175	$1,992	$20,167
Future production costs	(3,968)	(453)	(4,421)
Future development costs	(1,335)	(309)	(1,644)
Future income tax expenses	(3,160)	(286)	(3,446)
Future net cash flows	9,712	944	10,656
10% annual discount for estimated timing of cash flows	(3,660)	(381)	(4,041)
Standardized measure of discounted future net cash flows	$ 6,052	$ 563	$ 6,615
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 5,748	$ 560	$ 6,308
Unconsolidated investment in Four Star			
Standardized measure of discounted future net cash flows	$ 617	$ —	$ 617
2004			
Future cash inflows[1]	$11,895	$1,077	$12,972
Future production costs	(3,585)	(135)	(3,720)
Future development costs	(1,234)	(274)	(1,508)
Future income tax expenses	(1,184)	(141)	(1,325)
Future net cash flows	5,892	527	6,419
10% annual discount for estimated timing of cash flows	(2,004)	(219)	(2,223)
Standardized measure of discounted future net cash flows	$ 3,888	$ 308	$ 4,196
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 3,907	$ 305	$ 4,212
2003			
Future cash inflows[1]	$13,302	$ 588	$13,890
Future production costs	(3,025)	(65)	(3,090)
Future development costs	(1,325)	(236)	(1,561)
Future income tax expenses	(1,695)	(75)	(1,770)
Future net cash flows	7,257	212	7,469
10% annual discount for estimated timing of cash flows	(2,449)	(128)	(2,577)
Standardized measure of discounted future net cash flows	$ 4,808	$ 84	$ 4,892
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,759	$ 84	$ 4,843

(1) United States excludes $502 million, $1 million and $104 million of future net cash outflows attributable to hedging activities in the years 2005, 2004 and 2003. Brazil excludes $4 million and $5 million of future net cash outflows attributable to hedging activities in 2005 and 2004.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $10.08 per MMBtu for natural gas and $61.04 per barrel of oil at December 31, 2005. In the United States, after adjustments for transportation and other charges, net prices were $8.33 per Mcf of gas, $57.42 per barrel of oil and $36.61 per barrel of NGL at December 31, 2005. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

The following are the principal sources of change in our consolidated worldwide standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,[1]		
	2005	2004	2003
		(In millions)	
Sales and transfers of natural gas and oil produced net of production costs	$(1,477)	$(1,470)	$(1,829)
Net changes in prices and production costs	2,884	29	1,586
Extensions, discoveries and improved recovery, less related costs	793	268	1,105
Changes in estimated future development costs	2	4	(16)
Previously estimated development costs incurred during the period	247	156	220
Revision of previous quantity estimates	47	(453)	(94)
Accretion of discount	476	568	526
Net change in income taxes	(1,093)	257	159
Purchases of reserves in place	956	114	5
Sale of reserves in place	(83)	(75)	(1,229)
Change in production rates, timing and other	(333)	(94)	150
Net change	$ 2,419	$ (696)	$ 583

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

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2005, 2004 and 2003
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2005					
Allowance for doubtful accounts	$ 198	$(68)	$ (54)[1]	$ (9)	$ 67
Valuation allowance on deferred tax assets	51	98[2]	(5)	20	164
Legal reserves	592	496	(516)[3][4]	2	574
Environmental reserves	380	65	(66)[4]	—	379
2004					
Allowance for doubtful accounts	$ 272	$(48)	$ (22)[1]	$ (4)	$ 198
Valuation allowance on deferred tax assets	9	46[2]	(4)	—	51
Legal reserves	1,169	145	(655)[3][4]	(67)	592
Environmental reserves	412	17	(51)[4]	2	380
2003					
Allowance for doubtful accounts	$ 176	$ 18	$ (31)[1]	$ 109[5]	$ 272
Valuation allowance on deferred tax assets	72	4	(68)[2]	1	9
Legal reserves	1,031	180[3]	(43)[4]	1	1,169
Environmental reserves	389	8	(52)[4]	67[6]	412

(1) Relates primarily to accounts written off.

(2) Relates primarily to valuation allowances for deferred tax assets related to the Western Energy Settlement, foreign ceiling test charges, foreign asset impairments and state and foreign net operating loss carryovers.

(3) Relates to our Western Energy Settlement of $104 million in 2003. In 2005 and 2004, we paid approximately $442 million and $602 million to the settling parties.

(4) Relates primarily to payments for various litigation reserves, including the Western Energy Settlement, environmental remediation reserves or revenue crediting and rate settlement reserves.

(5) Relates primarily to receivables from trading counterparties, reclassified due to bankruptcy or declining credit that have been accounted for within our price risk management activities.

(6) Relates primarily to liabilities previously classified in our petroleum discontinued operations, but reclassified as continuing operations due to our retention of these obligations.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2005, we carried out an evaluation under the supervision and with the participation of our management, including our CEO and our CFO, as to the effectiveness, design and operation of our disclosure controls and procedures, as defined by the Securities Exchange Act of 1934, as amended. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely.

Based on the results of this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2005.

See Part II, Item 8 Financial Statements and Supplementary Data under Management's Annual Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the fourth quarter 2005.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information included under the captions "Corporate Governance", "Proposal No. 1 — Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2006 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

As a result of the promulgation of Rule 10b5-1, we allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of inside information at the time of the trade to execute pre-established trades of our securities for the officer or director according to fixed parameters. Effective November 9, 2005, Mr. Kuehn entered into a trading plan in compliance with Rule 10b5-1 for 125,000 of his stock options that expire on September 2, 2006. The sale period under the trading plan is effective November 16, 2005 to September 1, 2006 and will effectuate an exercise and sale of the shares at certain minimum limit prices provided by the trading plan.

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the captions "Information about the Board of Directors and Committees", "Executive Compensation", "Performance Graph", "Compensation Committee Report on Executive Compensation" and "Employment Contracts, Termination of Employment, Change in Control Agreements and Director and Officer Indemnification Agreements" in our proxy statement for the 2006 Annual Meeting of Stockholders is incorporated herein by reference.

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

Information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information Table" in our proxy statement for the 2006 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information appearing under the caption "Certain Relationships and Related Transactions" in our proxy statement for the 2006 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees for professional services rendered for El Paso by PricewaterhouseCoopers LLP for the years ended December 31, 2005 and 2004, were (in thousands):

	December 31, 2005	December 31, 2004
Audit	$14,428	$19,818
Audit Related	2,050	1,772
Tax	513	453
Total	$16,991	$22,043

The *Audit* fees for the years ended December 31, 2005 and 2004, respectively, were for professional services rendered for the audits of the consolidated financial statements of El Paso, statutory subsidiary and equity investee audits; the audit of our internal controls in compliance with Section 404 of the Sarbanes-Oxley Act of 2002; the review of documents filed with the Securities and Exchange Commission; and consents and the issuance of comfort letters.

The *Audit Related* fees for the years ended December 31, 2005 and December 31, 2004, respectively, were for professional services rendered for employee benefit plans; the carve-out audits of businesses disposed of by El Paso; responding to inquiries of certain federal agencies related to audit work performed; and accounting consultations.

Tax fees for the years ended December 31, 2005 and 2004, respectively, were for professional services related to tax compliance and tax planning.

El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. The Audit Committee has considered whether the provision of non-audit services by PricewaterhouseCoopers LLP is compatible with maintaining auditor independence and has determined that auditor independence has not been compromised.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial statements.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners and the Management Committee of

Midland Cogeneration Venture Limited Partnership:

We have completed integrated audits of Midland Cogeneration Venture Limited Partnership's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Midland Cogeneration Venture Limited Partnership (a Michigan Limited Partnership) and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements 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.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9(A), that the Partnership maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 20, 2006

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31,
(In Thousands)

	2005	2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 360,562	$ 125,781
Accounts and notes receivable — related parties	30,514	54,368
Accounts receivable	108,393	42,984
Gas inventory	16,138	17,509
Unamortized property taxes	18,238	18,060
Derivative assets	241,135	94,977
Broker margin accounts and prepaid expenses	20,294	13,147
Total current assets	795,274	366,826
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment	2,479,071	2,466,944
Pipeline	21,432	21,432
Total property, plant and equipment	2,500,503	2,488,376
Accumulated depreciation (Note 3)	(2,276,089)	(1,062,821)
Net property, plant and equipment	224,414	1,425,555
OTHER ASSETS:		
Restricted investment securities held-to-maturity	90,915	139,410
Derivative assets non-current	186,336	24,337
Deferred financing costs, net of accumulated amortization of $19,580 and $18,498, respectively	5,385	6,467
Prepaid gas costs, spare parts deposit, materials and supplies	15,554	17,782
Total other assets	298,190	187,996
TOTAL ASSETS	$ 1,317,878	$ 1,980,377

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31, Continued
(In Thousands)

	2005	2004
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities — related parties	$ 16,651	$ 12,772
Accounts payable and accrued liabilities	118,663	69,921
Gas supplier funds on deposit — related parties	44,353	—
Gas supplier funds on deposit	148,650	19,613
Interest payable	45,057	47,738
Current portion of long-term debt	63,459	76,548
Total current liabilities	436,833	226,592
NON-CURRENT LIABILITIES:		
Long-term debt	878,638	942,097
Other	805	1,712
Total non-current liabilities	879,443	943,809
COMMITMENTS AND CONTINGENCIES (Notes 8 and 9)		
TOTAL LIABILITIES	1,316,276	1,170,401
PARTNERS' EQUITY	1,602	809,976
TOTAL LIABILITIES AND PARTNERS' EQUITY	$ 1,317,878	$ 1,980,377

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF OPERATIONS FOR THE Years Ended December 31, (In Thousands)

	2005	2004	2003
OPERATING REVENUES:			
Capacity	$ 403,722	$ 405,415	$ 404,681
Electric	167,577	225,154	162,093
Steam	20,600	19,090	17,638
Total operating revenues	591,899	649,659	584,412
OPERATING EXPENSES:			
Fuel costs (Note 2)	124,610	413,061	254,988
Depreciation	73,845	88,712	89,437
Operations	16,114	18,769	16,943
Maintenance	7,958	13,508	15,107
Property and single business taxes	29,580	28,834	30,040
Administrative, selling and general	15,871	11,236	9,959
Asset impairment loss (Note 3)	1,159,000	—	—
Total operating expenses	1,426,978	574,120	416,474
OPERATING INCOME (LOSS)	(835,079)	75,539	167,938
OTHER INCOME (EXPENSE):			
Interest and other income	14,365	5,460	5,100
Interest expense	(96,730)	(104,618)	(113,247)
Total other income (expense), net	(82,365)	(99,158)	(108,147)
NET INCOME (LOSS)	$ (917,444)	$ (23,619)	$ 59,791

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) FOR THE Years Ended December 31,
(In Thousands)

	General Partners	Limited Partners	Total
BALANCE, DECEMBER 31, 2002	$ 627,947	$ 106,363	$ 734,310
Comprehensive Income			
Net Income	52,056	7,735	59,791
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	34,484	5,125	39,609
Reclassification adjustments recognized in net income above	(30,153)	(4,481)	(34,634)
Total other comprehensive income	4,331	644	4,975
Total Comprehensive Income	56,387	8,379	64,766
BALANCE, DECEMBER 31, 2003	$ 684,334	$ 114,742	$ 799,076
Comprehensive Income			
Net Loss	(20,563)	(3,056)	(23,619)
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	62,292	9,256	71,548
Reclassification adjustments recognized in net income above	(32,239)	(4,790)	(37,029)
Total other comprehensive income	30,053	4,466	34,519
Total Comprehensive Income	9,490	1,410	10,900
BALANCE, DECEMBER 31, 2004	$ 693,824	$ 116,152	$ 809,976
Comprehensive Income			
Net Loss	(798,754)	(118,690)	(917,444)
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	141,965	21,095	163,060
Reclassification adjustments recognized in net income above	(21,496)	(3,194)	(24,690)
Dedesignated cash flow hedges (Note 2)	(25,509)	(3,791)	(29,300)
Total other comprehensive income	94,960	14,110	109,070
Total Comprehensive Loss	(703,794)	(104,580)	(808,374)
BALANCE, DECEMBER 31, 2005	$ (9,970)	$ 11,572	$ 1,602

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF CASH FLOWS FOR THE Years Ended December 31, (In Thousands)

	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (917,444)	$ (23,619)	$ 59,791
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation and amortization	74,927	89,925	90,792
Asset impairment loss	1,159,000	—	—
(Increase) decrease in derivative assets	(199,087)	20,130	4,906
Increase in accounts receivable	(41,555)	(15,214)	(1,211)
(Increase) decrease in gas inventory	1,371	2,789	(732)
(Increase) decrease in unamortized property taxes	(178)	(388)	683
Increase in broker margin accounts and prepaid expenses	(7,147)	(5,046)	(4,778)
(Increase) decrease in prepaid gas costs, materials and supplies	2,228	3,841	(8,704)
Increase (decrease) in accounts payable and accrued liabilities	52,621	25,775	(712)
Increase in gas supplier funds on deposit	173,390	15,096	4,517
Decrease in interest payable	(2,681)	(5,271)	(3,377)
Increase (decrease) in other non-current liabilities	(907)	(1,197)	311
Net cash provided by operating activities	294,538	106,821	141,486
CASH FLOWS FROM INVESTING ACTIVITIES:			
Plant modifications and purchases of plant equipment	(31,704)	(20,460)	(33,278)
Maturity of restricted investment securities held-to-maturity	318,192	674,553	601,225
Purchase of restricted investment securities held-to-maturity	(269,697)	(674,208)	(602,279)
Net cash provided by (used in) investing activities	16,791	(20,115)	(34,332)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayment of financing obligation	(76,548)	(134,576)	(93,928)
Net cash used in financing activities	(76,548)	(134,576)	(93,928)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	234,781	(47,870)	13,226
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	125,781	173,651	160,425
CASH AND EQUIVALENTS AT END OF PERIOD	$ 360,562	$ 125,781	$ 173,651

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) The Partnership and Associated Risks

MCV was organized to construct, own and operate a combined-cycle, gas-fired cogeneration facility (the "Facility") located in Midland, Michigan. MCV was formed on January 27, 1987, and the Facility began commercial operation in 1990.

In 1992, MCV had acquired the outstanding common stock of PVCO Corp., a previously inactive company. MCV and PVCO Corp. then entered into a partnership agreement to form MCV Gas Acquisition General Partnership ("MCV GAGP") for the purpose of buying and selling natural gas on the spot market and other transactions involving natural gas activities. PVCO Corp. and MCV GAGP were dissolved on January 30, 2004 and July 2, 2004, respectively, due to inactivity.

The Facility has a net electrical generating capacity of approximately 1500 MW (including approximately 100 MW of duct burner generation from five of six duct burners, which are currently unavailable for operational use) and approximately 1.5 million pounds of process steam capacity per hour. MCV has entered into three principal energy sales agreements. MCV has contracted to (i) supply up to 1240 MW of electric capacity ("Contract Capacity") to Consumers Energy Company ("Consumers") under the Power Purchase Agreement ("PPA"), for resale to its customers through 2025, (ii) supply electricity and steam to The Dow Chemical Company ("Dow") through 2008 and 2015, respectively, under the Steam and Electric Power Agreement ("SEPA") and (iii) supply steam to Dow Corning Corporation ("DCC") under the Steam Purchase Agreement ("SPA") through 2011 (see Note 8, "Commitments and Other Agreements — Steam Purchase Agreement"). From time to time, MCV enters into other sales agreements for the sale of excess capacity and/or energy available above MCV's internal use and obligations under the PPA, SEPA and SPA. Results of operations are primarily dependent on successfully operating the Facility at or near contractual capacity levels and on Consumers' ability to perform its obligations under the PPA. Sales pursuant to the PPA have historically accounted for over 90% of MCV's revenues.

The PPA permits Consumers, under certain conditions, to reduce the capacity and energy charges payable to MCV and/or to receive refunds of capacity and energy charges paid to MCV if the Michigan Public Service Commission ("MPSC") does not permit Consumers to recover from its customers the capacity and energy charges specified in the PPA (the "regulatory-out" provision). Until September 15, 2007, however, the capacity charge may not be reduced below an average capacity rate of 3.77 cents per kilowatt-hour for the available Contract Capacity notwithstanding the "regulatory-out" provision. Consumers and MCV are required to support and defend the terms of the PPA.

The Facility is a qualifying cogeneration facility ("QF") originally certified by the Federal Energy Regulatory Commission ("FERC") under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). In order to maintain QF status, certain operating and efficiency standards must be maintained on a calendar-year basis and certain ownership limitations must be met. In the case of a topping-cycle generating plant such as the Facility, the applicable operating standard requires that the portion of total energy output that is put to some useful purpose other than facilitating the production of power (the "Thermal Percentage") be at least 5%. In addition, the Facility must achieve a PURPA efficiency standard (the sum of the useful power output plus one-half of the useful thermal energy output, divided by the energy input (the "Efficiency Percentage")) of at least 45%. If the Facility maintains a Thermal Percentage of 15% or higher, the required Efficiency Percentage is reduced to 42.5%. Since 1990, the Facility has achieved the applicable Thermal and Efficiency Percentages. For the twelve months ended December 31, 2005, the Facility achieved a Thermal Percentage of 23.7% and an Efficiency Percentage of 47.2%. The loss of QF status could, among other things, cause MCV to lose its rights under PURPA to sell power from the Facility to Consumers at Consumers' "avoided cost" and subject MCV to additional federal and state regulatory requirements.

At both the state and federal level, efforts continue to restructure the electric industry. A significant issue to MCV is the potential for future regulatory denial of recovery by Consumers from its customers of above market PPA costs Consumers pays MCV. At the state level, the MPSC entered a series of orders from

June 1997 through February 1998 (collectively the "Restructuring Orders"), mandating that utilities "wheel" third-party power to the utilities' customers, thus permitting customers to choose their power provider. MCV, as well as others, filed an appeal in the Michigan Court of Appeals to protect against denial of recovery by Consumers of PPA charges. The Michigan Court of Appeals found that the Restructuring Orders do not unequivocally disallow such recovery by Consumers and, therefore, MCV's issues were not ripe for appellate review and no actual controversy regarding recovery of costs could occur until 2008, at the earliest. In June 2000, the State of Michigan enacted legislation which, among other things, states that the Restructuring Orders (being voluntarily implemented by Consumers) are in compliance with the legislation and enforceable by the MPSC. The legislation provides that the rights of parties to existing contracts between utilities (like Consumers) and QFs (like MCV), including the rights to have the PPA charges recovered from customers of the utilities, are not abrogated or diminished, and permits utilities to securitize certain stranded costs, including PPA charges.

In 1999, the U.S. District Court granted summary judgment to MCV declaring that the Restructuring Orders are preempted by federal law to the extent they prohibit Consumers from recovering from its customers any charge for avoided costs (or "stranded costs") to be paid to MCV under PURPA pursuant to the PPA. In 2001, the United States Court of Appeals ("Appellate Court") vacated the U.S. District Court's 1999 summary judgment and ordered the case dismissed based upon a finding that no actual case or controversy existed for adjudication between the parties. The Appellate Court determined that the parties' dispute is hypothetical at this time and the QFs' (including MCV) claims are premised on speculation about how an order might be interpreted by the MPSC, in the future.

Two significant issues that could affect MCV's future financial performance are the price of natural gas and Consumers' ability/obligation to pay PPA charges. First, the Facility is wholly dependent upon natural gas for its fuel supply and a substantial portion of the Facility's operating expenses consist of the costs of natural gas. MCV recognizes that its existing gas contracts are not sufficient to satisfy the anticipated gas needs over the term of the PPA and, as such, no assurance can be given as to the availability or price of natural gas after the expiration of the existing gas contracts, since natural gas prices have historically been volatile and extremely difficult to forecast. In addition, there is no consensus among forecasters of natural gas prices as to whether the price or range will increase, decrease or remain at current levels over any period of time. Since December 2004, the spot price of natural gas has risen by approximately $6.50 per million British thermal units ("MMBtu"), and natural gas futures contract prices (as of the last trading day of each month) for the period 2006 to 2010 are an average of approximately $3.80 per MMBtu higher. To the extent that the costs associated with production of electricity rise faster than the energy charge payments, MCV's financial performance will be negatively affected. The extent of such impact will depend upon the amount of the average energy charge payable under the PPA, which is based upon costs incurred at Consumers' coal-fired plants and upon the amount of energy scheduled by Consumers for delivery under the PPA. Even with the RCA and RDA, if gas prices stay at present levels or increase, the results of operating the Facility would be adversely affected and could result in MCV failing to meet its financing obligations. Second, Consumers' ability/obligation to pay PPA charges may be affected by an MPSC order denying Consumers' recovery from ratepayers. This issue is likely to be addressed in the timeframe of 2007 or beyond. MCV continues to monitor the current and long-term trends in natural gas prices, and to participate in MPSC matters, as appropriate. However, given the unpredictability of these factors, the overall economic impact upon MCV of changes in energy charges payable under the PPA and in future fuel costs under new or existing contracts, cannot accurately be predicted. MCV management cannot, at this time, predict the future impact or outcome of these matters. (See Note 3 — Asset Impairment).

(2) Summary of Significant Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Following is a discussion of MCV's significant accounting policies.

Principles of Consolidation and Operating Segments

The consolidated financial statements included the accounts of MCV and its wholly-owned subsidiaries, PVCO Corp. and MCV GAGP. Previously, all material transactions and balances among entities, which comprise MCV, had been eliminated in the consolidated financial statements. The 2004 dissolution of these wholly-owned subsidiaries had no impact on the financial position and results of operations. In addition, under SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," MCV has determined that it has one reportable segment.

Revenue Recognition

MCV recognizes revenue for the sale of variable energy and fixed energy when delivered. Capacity and other installment revenues are recognized based on plant availability or other contractual arrangements.

Fuel Costs

MCV's fuel costs are those costs associated with securing natural gas, transportation and storage services necessary to generate electricity and steam from the Facility. These costs are recognized in the income statement based upon actual volumes burned to produce the delivered energy, as well as gains and losses resulting from mark-to-market and natural gas hedging activity. For further disclosure, see sections, "Mark-to-Market Activity" and "Natural Gas Supply Futures and Options which Qualify for Hedge Accounting," within this Note 2. In addition, MCV engages in certain cost mitigation activities to offset the fixed charges MCV incurs for these activities. The gains or losses resulting from these activities have resulted in net gains of approximately $15.8 million, $6.7 million and $7.7 million for the years ended 2005, 2004 and 2003, respectively. These net gains are reflected as a component of fuel costs.

In 2004, MCV and Consumers entered into a Resource Conservation Agreement ("RCA") and a Reduced Dispatch Agreement ("RDA") which, among other things, provides that Consumers will economically dispatch MCV, based upon the market price of natural gas, if certain conditions are met. Such dispatch is expected to reduce electric production from historic levels, as well as decrease gas consumption by MCV. The RCA provides that Consumers has a right of first refusal to purchase, at market prices, the gas conserved under the RCA. The RCA and RDA provide for the sharing of savings realized by not having to generate electricity. The RCA and RDA were approved by the MPSC on January 25, 2005 and MCV and Consumers accepted the terms of the MPSC order. The RCA and RDA became effective January 27, 2005. This MPSC order has been appealed by certain parties. MCV management cannot predict the final outcome of this appeal. Effective October 23, 2004, MCV and Consumers entered into an interim dispatch mitigation program for energy dispatch above 1100 MW up to 1240 MW of Contract Capacity under the PPA. This program, which was structured very similarly to the RCA and RDA, was terminated on January 27, 2005 with the effective date of the RCA/RDA which superceded this interim program.

Accounts Receivable

Accounts receivable and accounts receivable-related parties are recorded at the billed amount and do not bear interest. MCV evaluates the need for an allowance for doubtful accounts using MCV's best estimate of the amount of probable credit losses. At December 31, 2005 and 2004, no allowance was provided since typically all receivables are collected within 30 days of each month end.

Inventory

MCV's inventory of natural gas is stated at the lower of cost or market, and valued using the last-in, first-out ("LIFO") method. Inventory includes the costs of purchased gas, variable transportation and storage. The amount of reserve to reduce inventories from first-in, first-out ("FIFO") basis to the LIFO basis at December 31, 2005 and 2004, was $14.7 million and $10.3 million, respectively. Inventory cost, determined on a FIFO basis, approximates current replacement cost.

Materials and Supplies

Materials and supplies are stated at the lower of cost or market using the weighted average cost method. The majority of MCV's materials and supplies are considered replacement parts for MCV's Facility.

Depreciation

Original plant, equipment and pipeline were valued at cost for the constructed assets and at the asset transfer price for purchased and contributed assets, and are depreciated using the straight-line method over an estimated useful life of 35 years, which is the term of the PPA, except for the hot gas path components of the GTGs which are primarily being depreciated over a 25-year life. Plant construction and additions, since commercial operations in 1990, are depreciated using the straight-line method over the remaining life of the plant which currently is 20 years. Major renewals and replacements, which extend the useful life of plant and equipment are capitalized, while maintenance and repairs are expensed when incurred. Major equipment overhauls are capitalized and amortized to the next equipment overhaul. Personal property is depreciated using the straight-line method over an estimated useful life of 5 to 15 years. The cost of assets and related accumulated depreciation are removed from the accounts when sold or retired, and any resulting gain or loss reflected in operating income. (See Note 3 — Asset Impairment.)

Federal Income Tax

MCV is not subject to Federal or State income taxes. Partnership earnings are taxed directly to each individual partner.

Statement of Cash Flows

All liquid investments purchased with a maturity of three months or less at time of purchase are considered to be current cash equivalents.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents and short-term investments approximate fair value because of the short maturity of these instruments. MCV's short-term investments, which are made up of investment securities held-to-maturity, as of December 31, 2005 and December 31, 2004 have original maturity dates of approximately one year or less. The unique nature of the negotiated financing obligation discussed in Note 7 makes it unnecessary to estimate the fair value of the Owner Participants' underlying debt and equity instruments supporting such financing obligation, since SFAS No. 107 "Disclosures about Fair Value of Financial Instruments" does not require fair value disclosure for the lease obligation.

Accounting for Derivative Instruments and Hedging Activities

MCV records every derivative instrument on the balance sheet as either an asset or liability measured at its fair value, except for those which qualify for the normal purchases and normal sales exception. SFAS No. 133 requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges in some cases allows a derivative's gains and losses to offset related results on the hedged item in the income statement or permits recognition of the hedge results in other comprehensive income, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Electric Sales Agreements

Prior to April 1, 2005, MCV had concluded that its electric sales agreements did not qualify as derivatives under SFAS No. 133, due to the lack of an active energy market in the State of Michigan. With the launch of the Midwest Independent System Operator (MISO) market effective April 1, 2005, MCV concluded that an active energy market may exist and as such, the agreements may qualify as derivatives. MCV currently believes that these electric sales agreements qualify under SFAS No. 133 for the normal purchase and normal sale exception. Therefore, these contracts continue to not be recognized at fair value on the balance sheet.

Natural Gas Supply Contracts

MCV management believes that its long-term natural gas contracts, except for those which contain volume optionality and the long-term gas contracts under the RCA/RDA, qualify under SFAS No. 133 for the normal purchases and normal sales exception. Therefore, these contracts are currently not recognized at fair value on the balance sheet.

Natural Gas Credit Risk

MCV is exposed to the risk of loss from failure of its counterparties, under its natural gas supply and derivative contracts, to comply with the terms of the respective contracts, which includes non-delivery under the natural gas supply contracts. To protect against this loss, many of MCV's gas supply contracts have credit support requirements that can be triggered by changes in the financial condition of MCV or the gas supplier, price changes in the forward gas market or the quantity of gas purchases (see Note 6 — Gas Supplier Funds on Deposit). MCV management monitors this risk through the periodic review of the credit and financial condition of these counterparties and as of December 31, 2005, believes the risk of noncompliance to be remote. If any of these counterparties fails to deliver on their requirements, MCV does not expect this would have a material impact on its financial condition or cash flows.

Mark-to-Market Activity

MCV holds certain long-term gas contracts that do not qualify for the normal purchases and sales exception, under SFAS No. 133, because (1) these gas contracts contain volume optionality and/or (2) are gas contracts associated with the implementation of the RCA/RDA in January 2005. With the implementation of the RCA/RDA, MCV determined that additional gas contracts no longer qualified under the normal purchases and sales exception, because the contracted gas will not be consumed for electric production. Therefore, both the contracts with volume optionality and the contracts affected by the RCA/RDA are being accounted for as derivatives, which do not qualify for hedge accounting treatment. In addition, the financial derivatives associated with the long-term gas contracts now under the RCA/RDA that were previously recognized as cash flow hedges in other comprehensive income were designated as hedges in the first quarter of 2005 and marked-to-market through earnings since the previously hedged long-term gas contracts no longer qualify for the normal purchase and sales exception. MCV expects future earnings volatility on all of these contracts as changes in the mark-to-market recognition are recorded in earnings on a quarterly basis.

The cumulative mark-to-market gain through December 31, 2005 of $255.9 million is recorded as a current and non-current derivative asset on the balance sheet, as described below. These assets will reverse over the remaining life of these contracts as the unrealized gains and losses are realized at contract settlement. For the twelve months ended December 31, 2005 and December 31, 2004, MCV recorded in "Fuel costs" a gain of $200.4 million and a loss of $19.4 million, respectively, for the net mark-to-market adjustment associated with these contracts. In addition, as of December 31, 2005 and December 31, 2004, MCV recorded "Derivative assets" in Current Assets in the amount of $198.5 million and $31.4 million, respectively, and for the same periods recorded "Derivative assets, non-current" in Other Assets in the amount of $57.4 million and $24.3 million, respectively, representing the mark-to-market value on these long-term natural gas contracts and associated financial positions. MCV has also recorded a net $93.8 million gain in earnings from recognized gains on the financial positions associated with the long-term gas contracts.

Natural Gas Supply Futures and Options Which Qualify for Hedge Accounting

To manage market risks associated with the volatility of natural gas prices, MCV maintains a gas hedging program. MCV enters into natural gas futures contracts, option contracts, and over the counter swap transactions ("OTC swaps") in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are being utilized principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize MCV's existing gas supply, storage and transportation arrangements.

These financial instruments are derivatives under SFAS No. 133 and the contracts that are utilized to secure the anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133, since they hedge the price risk associated with the cost of natural gas. MCV also engages in cost mitigation activities to offset the fixed charges MCV incurs in operating the Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for MCV and do not qualify as hedges under SFAS No. 133. Therefore, the resulting mark-to-market gains and losses from cost mitigation activities are flowed through MCV's earnings.

For the twelve months ended December 31, 2005, MCV has recognized in other comprehensive income, an unrealized gain of $109.1 million on the gas futures contracts and OTC swaps (including a $29.3 million loss of dedesignated cash flow hedges), which are hedges of forecasted purchases for plant use of market priced gas. This resulted in a net $174.8 million gain in other comprehensive income (loss) as of December 31, 2005. This balance represents natural gas futures, options and OTC swaps with maturities ranging from January 2006 to December 2009, of which $45.9 million of this gain is expected to be reclassified into earnings within the next twelve months. MCV also has recorded, as of December 31, 2005, a $42.6 million "Derivative assets," in Current Assets and for the same period a $128.9 million "Derivative asset — non-current" in Other Assets, representing the mark-to-market gain on natural gas futures for anticipated projected electric and steam sales accounted for as hedges. In addition, for the twelve months ended December 31, 2005, MCV has recorded a net $24.7 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $2.7 million loss in earnings from hedges related to cost mitigation activities.

For the twelve months ended December 31, 2004, MCV recognized an unrealized $34.5 million increase in other comprehensive income on the futures contracts, which are hedges of forecasted purchases for plant use of market priced gas, which resulted in a $65.8 million gain balance in other comprehensive income as of December 31, 2004. As of December 31, 2004, MCV had recorded a $63.6 million current derivative asset in "Derivative assets." For the twelve months ended December 31, 2004, MCV had recorded a net $36.5 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $1.8 million gain in earnings from cost mitigation activities.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income reflects the following balances at December 31 (thousands):

	2005	2004	2003
Beginning Accumulated Other Comprehensive Income	$ 65,774	$ 31,255	$ 26,280
Unrealized gain on hedging activities	163,060	71,548	39,609
Reclassification adjustments recognized in net income	(24,690)	(37,029)	(34,634)
Dedesignated cash flow hedges	(29,300)	—	—
Ending Accumulated Other Comprehensive Income	$174,844	$ 65,774	$ 31,255

New Accounting Standard

In March 2005, the FASB issued FAS Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations." This interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. The term refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event. This interpretation is effective for

MCV on December 31, 2005. MCV has reviewed its current commitments and key contracts to operate the MCV Facility. Based on this review, MCV finds no material conditional asset retirement obligations that need to be accrued upon the adoption of this interpretation.

(3) Asset Impairment

SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" requires that MCV review, on a forward-looking basis, the recoverability of its long-lived assets (such as property, plant and equipment) whenever events or circumstances indicate that the carrying amount of the long-lived assets may not be recoverable. Recoverability of "assets to be held and used" is measured by a comparison of the carrying amount of the assets to the estimated undiscounted future cash flows expected to be generated by the assets, over their remaining useful life. If the carrying amount of the assets exceeds the estimated undiscounted future cash flows expected to be generated, an impairment charge is recognized in the amount by which the carrying amount of the long-lived assets exceed their fair value.

The single largest cost to MCV of producing electricity is the cost of natural gas. Natural gas prices have increased substantially in recent months. As a result, MCV has continuously monitored trends in and forecasts of natural gas prices and their estimated effect on the economics of operating the Facility. In April 2005, MCV performed its usual semi-annual economic analysis using then current market prices and apparent trends in and forecasts of natural gas prices; the results of this update of its economic analysis did not indicate an impairment of MCV's long-lived assets.

After the April 2005 economic analysis was performed, natural gas prices rose dramatically as a result of events and circumstances, which created tight supply and higher market demand for natural gas. For example, hurricane disruptions in the supply of gas in the third quarter of 2005 drastically reduced Gulf Coast natural gas production and distribution, causing a further upward spike in NYMEX forward natural gas prices, as well as third-parties' forecasts for natural gas prices. As a result, the MCV Partnership determined that updating its impairment analysis, considering revised forward natural gas price assumptions and third parties' forecasts of natural gas prices, among others circumstances was appropriate to evaluate the recoverability of the asset group. The asset group under SFAS No. 144 represents all assets and liabilities that impact the lowest level of identifiable cash flows to be generated to recover the MCV's long-lived assets. For the MCV, the asset group included net property, plant and equipment and the fair value of derivative assets, as discussed in Note 2 — "Summary of Significant Accounting Policies", both of which impact management's estimate of the net cash flows to be generated by the MCV to recover these long-lived assets. Based on MCV's 2005 third quarter updated impairment analysis, MCV concluded that the carrying value of the MCV's asset group exceeded cash flows that would be generated by the Facility on an undiscounted basis and therefore, under SFAS No. 144, an impairment adjustment was required to reduce the carrying value to the estimated fair value. The fair value of the asset group was determined by discounting a set of probability-weighted streams of future cash flows at a 4.3% risk free interest rate. This impairment adjustment was recorded in the third quarter of 2005 for $1,159.0 million under "Asset impairment loss" in MCV's Statement of Operations. MCV will continue to monitor the current and long-term trends in natural gas prices and other factors, as appropriate. Since the 2005 third quarter impairment analysis, gas prices have decreased, however, should natural gas prices remain at present levels or increase, the results of operating the Facility would be adversely affected in the long term and could result in MCV failing to meet its financial obligations under the sale and leaseback transactions and other contracts.

(4) Restricted Investment Securities Held-To-Maturity

Non-current restricted investment securities held-to-maturity have carrying amounts that approximate fair value because of the short maturity of these instruments and consist of the following at December 31 (in thousands):

	2005	2004
Funds restricted for rental payments pursuant to the Overall Lease Transaction	$90,111	$138,150
Funds restricted for management non-qualified plans	804	1,260
Total	$90,915	$139,410

(5) Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consist of the following at December 31 (in thousands):

	2005	2004
Accounts payable — related parties	$ 16,651	$12,772
Accounts payable — non-related		
Trade creditors	$100,956	$53,476
Property and single business taxes	11,088	11,833
Other	6,619	4,612
Total accounts payable — non-related	$118,663	$69,921

(6) Gas Supplier Funds on Deposit

Pursuant to individual gas contract terms with counterparties, including margin accounts with futures and option brokers, deposit amounts or letters of credit may be required by one party to the other based upon the net amount of exposure. The net amount of exposure will vary with changes in market prices, credit provisions and various other factors. Collateral paid or received will be posted by one party to the other based on the net amount of the exposure. Interest is earned on funds on deposit. MCV has paid or received the following as of December 31 (in thousands):

	2005	2004
Cash or letters of credit supplied by MCV to others:		
Cash paid, recorded in “Broker margin accounts and prepaid expenses”	$ 16,520	$ 8,670
Letters of credit provided to others	2,430	2,430
Cash or letters of credit supplied to MCV by others:		
Cash received, recorded in “Gas supplier funds on deposit”	148,650	19,613
Cash received by El Paso (a related party), recorded in “Gas supplier funds on deposit — related parties”	44,353	—
Letters of credit provided to MCV from non-related parties	21,700	24,600
Letters of credit provided to MCV by El Paso (a related party)	385,700	184,000

(7) Long-Term Debt

Long-term debt consists of the following at December 31 (in thousands):

	2005	2004
Financing obligation, maturing through 2015, payable in semi-annual installments of principal and interest, collateralized by property, plant and equipment	$942,097	$1,018,645
Less current portion	(63,459)	(76,548)
Total long-term debt	$878,638	$ 942,097

Financing Obligation

In June 1990, MCV obtained permanent financing for the Facility by entering into sale and leaseback agreements ("Overall Lease Transaction") with a lessor group, related to substantially all of MCV's fixed assets. Proceeds of the financing were used to retire borrowings outstanding under existing loan commitments, make a capital distribution to the Partners and retire a portion of notes issued by MCV to MEC Development Corporation ("MDC") in connection with the transfer of certain assets by MDC to MCV. In accordance with SFAS No. 98, "Accounting For Leases," the sale and leaseback transaction has been accounted for as a financing arrangement.

The financing obligation utilizes the effective interest rate method, which is based on the minimum lease payments required through the end of the basic lease term of 2015 and management's estimate of additional anticipated obligations after the end of the basic lease term. The effective interest rate during the remainder of the basic lease term is approximately 9.4%.

Under the terms of the Overall Lease Transaction, MCV sold undivided interests in all of the fixed assets of the Facility for approximately $2.3 billion, to five separate owner trusts ("Owner Trusts") established for the benefit of certain institutional investors ("Owner Participants"). U.S. Bank National Association serves as owner trustee ("Owner Trustee") under each of the Owner Trusts, and leases undivided interests in the Facility on behalf of the Owner Trusts to MCV for an initial term of 25 years. CMS Midland Holdings Company ("CMS Holdings"), currently a wholly owned subsidiary of Consumers, acquired a 35% indirect equity interest in the Facility through its purchase of an interest in one of the Owner Trusts.

The Overall Lease Transaction requires MCV to achieve certain rent coverage ratios and other financial tests prior to a distribution to the Partners. Generally, these financial tests become more restrictive with the passage of time. Further, MCV is restricted to making permitted investments and incurring permitted indebtedness as specified in the Overall Lease Transaction. The Overall Lease Transaction also requires filing of certain periodic operating and financial reports, notification to the lessors of events constituting a material adverse change, significant litigation or governmental investigation, and change in status as a qualifying facility under FERC proceedings or court decisions, among others. Notification and approval is required for plant modification, new business activities, and other significant changes, as defined. In addition, MCV has agreed to indemnify various parties to the sale and leaseback transaction against any expenses or environmental claims asserted, or certain federal and state taxes imposed on the Facility, as defined in the Overall Lease Transaction.

Under the terms of the Overall Lease Transaction and refinancing of the tax-exempt bonds, approximately $25.0 million of transaction costs were a liability of MCV and have been recorded as a deferred cost. Financing costs incurred with the issuance of debt are deferred and amortized using the interest method over the remaining portion of the 25-year lease term. Deferred financing costs of approximately $1.1 million, $1.2 million and $1.4 million were amortized in the years 2005, 2004 and 2003, respectively.

Interest and fees incurred related to long-term debt arrangements during 2005, 2004 and 2003 were $95.5 million, $103.4 million and $111.9 million, respectively.

Interest and fees paid during 2005, 2004 and 2003 were $98.2 million, $108.6 million and $115.4 million, respectively.

Minimum payments due under these long-term debt arrangements over the next five years are (in thousands):

	Principal	Interest	Total
2006	$ 63,459	$ 92,515	$155,974
2007	62,916	87,988	150,904
2008	67,753	83,163	150,916
2009	70,335	76,755	147,090
2010	62,917	70,085	133,002
	$327,380	$410,506	$737,886

Revolving Credit Agreement

MCV has also entered into a working capital line ("Working Capital Facility"), which expires August 26, 2006. Under the terms of the existing agreement, MCV can borrow up to the $50.0 million commitment, in the form of short-term borrowings or letters of credit collateralized by MCV's natural gas inventory and earned receivables. At any given time, borrowings and letters of credit are limited by the amount of the borrowing base, defined as 90% of earned receivables and 50% of natural gas inventory, capped at $15 million. MCV did not utilize the Working Capital Facility during the year 2005, except for letters of credit associated with normal business practices. At December 31, 2005, MCV had $47.6 million available under its Working Capital Facility. As of December 31, 2005, MCV's borrowing base was capped at the maximum amount available of $50.0 million and MCV had outstanding letters of credit in the amount of $2.4 million. MCV believes that amounts available to it under the Working Capital Facility along with available cash reserves will be sufficient to meet any working capital shortfalls that might occur in the near term.

Intercreditor Agreement

MCV has also entered into an Intercreditor Agreement with the Owner Trustee, Working Capital Lender, U.S. Bank National Association as Collateral Agent ("Collateral Agent") and the Senior and Subordinated Indenture Trustees. Under the terms of this agreement, MCV is required to deposit all revenues derived from the operation of the Facility with the Collateral Agent for purposes of paying operating expenses and rent. In addition, these funds are required to pay construction modification costs and to secure future rent payments. As of December 31, 2005, MCV has deposited $90.1 million into the reserve account. The reserve account is to be maintained at not less than $40 million nor more than $137 million (or debt portion of next succeeding basic rent payment, whichever is greater). Excess funds in the reserve account are periodically transferred to MCV. This agreement also contains provisions governing the distribution of revenues and rents due under the Overall Lease Transaction, and establishes the priority of payment among the Owner Trusts, creditors of the Owner Trusts, creditors of MCV and the Partnership.

(8) COMMITMENTS AND OTHER AGREEMENTS

MCV has entered into numerous commitments and other agreements related to the Facility. Principal agreements are summarized as follows:

Power Purchase Agreement

MCV and Consumers have executed the PPA for the sale to Consumers of a minimum amount of electricity, subject to the capacity requirements of Dow and any other permissible electricity purchasers. Consumers has the right to terminate and/or withhold payment under the PPA if the Facility fails to achieve certain operating levels or if MCV fails to provide adequate fuel assurances. In the event of early termination of the PPA, MCV would have a maximum liability of approximately $270 million if the PPA were terminated in the 12th through 24th years. The term of this agreement is 35 years from the commercial operation date and year-to-year thereafter.

Steam and Electric Power Agreement

MCV and Dow executed the SEPA for the sale to Dow of certain minimum amounts of steam and electricity for Dow's facilities.

If the SEPA is terminated, and Consumers does not fulfill MCV's commitments as provided in the Backup Steam and Electric Power Agreement, MCV will be required to pay Dow a termination fee, calculated at that time, ranging from a minimum of $60 million to a maximum of $85 million. This agreement provides for the sale to Dow of steam and electricity produced by the Facility for terms of 25 years and 15 years, respectively, commencing on the commercial operation date and year-to-year thereafter.

Steam Purchase Agreement

MCV and DCC executed the SPA for the sale to DCC of certain minimum amounts of steam for use at the DCC Midland site. Steam sales under the SPA commenced in July 1996. Termination of this agreement, prior to expiration, requires the terminating party to pay to the other party a percentage of future revenues, which would have been realized had the initial term of 15 years been fulfilled. The percentage of future revenues payable is 50% if termination occurs prior to the fifth anniversary of the commercial operation date and 33 1/3% if termination occurs after the fifth anniversary of this agreement. The term of this agreement is 15 years from the commercial operation date of steam deliveries under the contract and year-to-year thereafter.

In September 2005, MCV gave notice to DCC of its intent to terminate the SPA effective September 19, 2006, as provided for in the SPA. MCV informed DCC that it was willing to consider entering into another agreement with DCC at market-based pricing of steam. MCV has not been able to reach a new agreement with DCC at market-based pricing. The termination of the SPA is conditioned upon MCV making a payment to DCC 30 days prior to the effective date of the termination. The termination payment is for a certain portion of future revenues. The termination payment, which was accrued in December 2005 to "Administrative, Selling and General," is estimated to be $5.1 million. The contract termination is not expected to have any negative impact on MCV's PURPA QF certification (i.e., MCV's operating and efficiency requirements under PURPA will be met without steam sales to DCC).

Gas Supply Agreements

MCV has entered into gas purchase agreements with various producers for the supply of natural gas. The current contracted volume totals 238,665 MMBtu per day annual average for 2006. As of January 1, 2006, gas contracts with U.S. suppliers provide for the purchase of 176,010 MMBtu per day while gas contracts with Canadian suppliers provide for the purchase of 62,655 MMBtu per day. Some of these contracts require MCV to pay for a minimum amount of natural gas per year, whether or not taken. The estimated minimum commitments under these contracts based on current long-term prices for gas for the years 2006 through 2010 are $569.7 million, $683.8 million, $548.0 million, $478.5 million and $380.4 million, respectively. A portion of these payments may be utilized in future years to offset the cost of quantities of natural gas taken above the minimum amounts.

Gas Transportation Agreements

MCV has entered into firm natural gas transportation agreements with various pipeline companies. These agreements require MCV to pay certain reservation charges in order to reserve the transportation capacity. MCV incurred reservation charges in 2005, 2004 and 2003 of $34.5 million, $35.5 million and $34.8 million, respectively. The estimated minimum reservation charges required under these agreements for each of the years 2006 through 2010 are $30.5 million, $22.4 million, $22.4 million, $22.3 million and $21.7 million, respectively. These projections are based on current commitments.

Gas Turbine Service Agreements

MCV has a maintenance service and parts agreement with General Electric International, Inc. ("GEII"), which commenced July 1, 2004 ("GEII Agreement"). GEII is providing maintenance services and hot gas path parts for MCV's twelve GTGs, including an initial inventory of spare parts for the GTGs, providing qualified service personnel and supporting staff to assist MCV to perform scheduled inspections on the GTGs and to repair the GTGs at MCV's request. The GEII Agreement will cover four rounds of major GTG inspections, which are expected to be completed by the year 2015. MCV is to make monthly payments over the life of the contract totaling approximately $207 million (subject to escalations based on defined indices). The GEII Agreement can be terminated by either party for cause or convenience. Should termination for convenience occur, a buy out amount will be paid by the terminating party with payments ranging from approximately $19.0 million to $.9 million, based upon the number of operating hours utilized since commencement of the GEII Agreement.

Steam Turbine Service Agreement

MCV entered into a nine year Steam Turbine Maintenance Agreement with General Electric Company effective January 1, 1995, which is designed to improve unit reliability, increase availability and minimize unanticipated maintenance costs. In addition, this contract includes performance incentives and penalties, which are based on the length of each scheduled outage and the number of forced outages during a calendar year. Effective February 1, 2004, MCV and GE amended this contract to extend its term through August 31, 2007. MCV will continue making monthly payments over the life of the contract, which will total $22.3 million (subject to escalation based on defined indices). The parties have certain termination rights without incurring penalties or damages for such termination. Upon termination, MCV is only liable for payment of services rendered or parts provided prior to termination.

Site Lease

In December 1987, MCV leased the land on which the Facility is located from Consumers ("Site Lease"). MCV and Consumers amended and restated the Site Lease to reflect the creation of five separate undivided interests in the Site Lease as of June 1, 1990. Pursuant to the Overall Lease Transaction, MCV assigned these undivided interests in the Site Lease to the Owner Trustees, which in turn subleased the undivided interests back to MCV under five separate site subleases.

The Site Lease is for a term which commenced on December 29, 1987, and ends on December 31, 2035, including two renewal options of five years each. The rental under the Site Lease is $.6 million per annum, including the two five-year renewal terms.

(9) Contingencies

Property Taxes

In 1997, MCV filed a property tax appeal against the City of Midland at the Michigan Tax Tribunal ("MTT") contesting MCV's 1997 property taxes. Subsequently, MCV filed appeals contesting its property taxes for tax years 1998 — 2005 at the Michigan Tax Tribunal. A trial was held for tax years 1997 — 2000. The appeals for tax years 2001-2005 are being held in abeyance. In 2004, the Michigan Tax Tribunal issued its decision in MCV's tax appeal against the City of Midland for tax years 1997-2000 (the "MTT Decision"). MCV management has estimated that the MTT Decision and the impact of Michigan law (Proposal A, which caps taxable value increases) would result in a refund to MCV for the tax years 1997 — 2005 of at least $83.3 million, inclusive of interest as of December 31, 2005. The MTT Decision has been appealed to the Michigan Appellate Court by the City of Midland. MCV has filed a cross-appeal at the Michigan Appellate Court. On February 21, 2006, the Michigan Appellate Court primarily upheld the MTT Decision but remanded the case to the MTT for the limited purpose of clarification of whether the MTT erroneously included tax-exempt pollution-control equipment or property located outside the City of Midland in its concluded true cash value. If the MTT determines there was such double taxation, MCV will be entitled to a greater refund. The case is subject to further appeal. MCV management cannot predict the outcome of these legal proceedings. MCV has not recognized any of the above stated estimated refunds in earnings at this time.

NO_x Allowances

The United States Environmental Protection Agency ("US EPA") has approved the State of Michigan's — State Implementation Plan ("SIP"), which includes an interstate NOx budget and allowance trading program administered by the US EPA beginning in 2004. Each NOx allowance permits a source to emit one ton of NOx during the seasonal control period, which is from May 1 through September 30. NOx allowances may be bought or sold and unused allowances may be "banked" for future use, with certain limitations. MCV has excess NOx allowances to sell under this program. Consumers has given notice to MCV that it believes the ownership of the NOx allowances under this program, which have not been incorporated into the RCA/RDA program, belong, at least in part, to Consumers. MCV has initiated the dispute resolution process pursuant to the PPA to resolve this issue and the parties have entered into a standstill agreement deferring the resolution of this dispute. However, either party may terminate the standstill agreement at any time and reinstate the PPA's dispute resolution provisions. MCV management cannot predict the outcome of this issue. As of December 31, 2005, MCV has recorded in "Accounts payable and accrued liabilities", approximately $4.7 million for NOx allowances sold in 2005 and 2004, which are not part of the RCA/RDA and are pending resolution of ownership rights.

Environmental Issues

On July 12, 2004, the Michigan Department of Environmental Quality ("DEQ"), Air Control Division, issued MCV a "Letter of Violation" asserting that MCV violated its Air Use Permit to Install No. 209-02 ("PTI") by exceeding the carbon monoxide emission limit on the Unit 14 GTG duct burner and failing to maintain certain records in the required format. MCV declared five of the six duct burners as unavailable for operational use (which reduces the generation capability of the Facility by approximately 100 MW) and took other corrective action to address the DEQ's assertions. The one available duct burner was tested in April 2005 and its emissions met permitted levels due to the configuration of that particular unit. MCV disagrees with certain of the DEQ's assertions. MCV filed a response in July 2004 to address the Letter of Violation. On December 13, 2004, the DEQ informed MCV that it was pursuing an escalated enforcement action against MCV regarding the alleged violations of MCV's PTI. The DEQ also stated that the alleged violations are deemed federally significant and, as such, placed MCV on the US EPA's High Priority Violators List ("HPVL"). The DEQ and MCV are pursuing voluntary settlement of this matter, which will satisfy state and federal requirements and remove MCV from the HPVL. Any such settlement may involve a fine, but the DEQ has not, at this time, stated what, if any, fine they will seek to impose. MCV has accrued $50,000 for this issue. At this time, MCV management cannot predict the financial impact or outcome of this issue.

On July 13, 2004, the DEQ, Water Division, issued MCV a "Notice Letter" asserting MCV violated its National Pollutant Discharge Elimination System Permit by discharging heated process waste water into the storm water system, failing to document inspections, and other minor infractions ("alleged NPDES violations"). In August 2004, MCV filed a response to the DEQ letter covering the remediation for each of the DEQ's alleged violations. On October 17, 2005, the DEQ, Water Bureau, issued to MCV a "Compliance Inspection" report, which listed several minor violations and concerns that needed to be addressed by MCV. This report was issued in connection with an inspection of the Facility in September 2005, which was conducted for compliance and review of the Storm Water Pollution Prevention Plans ("SWPPP"). MCV submitted its updated SWPPP on December 1, 2005. MCV management believes it has resolved all issues associated with the Notice Letter and Compliance Inspection and does not expect any further DEQ actions on these matters.

(10) Retirement Benefits

Postretirement Health Care Plans

In 1992, MCV established defined cost postretirement health care plans ("Plans") that cover all full-time employees, excluding key management. The Plans provide health care credits, which can be utilized to purchase medical plan coverage and pay qualified health care expenses. Participants become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The Plans granted retroactive benefits for all employees hired prior to January 1, 1992. This prior service cost has been amortized to expense over a five-year period. MCV annually funds the current year service and interest cost as well as amortization of prior service cost to both qualified and non-qualified trusts. The MCV accounts for retiree medical benefits in accordance with SFAS 106, "Employers Accounting for Postretirement Benefits Other Than Pensions." This standard required the full accrual of such costs during the years that the employee renders service to the MCV until the date of full eligibility. The accumulated benefit obligation of the Plans were $5.4 million at December 31, 2005 and $4.9 million at December 31, 2004. The measurement date of these Plans was December 31, 2005.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was signed into law in December 2003. The Act expanded Medicare to include, for the first time, coverage for prescription drugs. The final SFAS No. 106-2 was issued in second quarter 2004 and supersedes SFAS No. 106-1, which MCV adopted during this same period. The adoption of this standard had no impact to MCV's financial position because MCV does not consider its Plans to be actuarially equivalent. The Plans benefits provided to eligible participants are not annual or on-going in nature, but are a readily exhaustible, lump-sum amount available for use at the discretion of the participant.

The following table reconciles the change in the Plans' benefit obligation and change in Plan assets as reflected on the balance sheet as of December 31 (in thousands):

	2005	2004
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 4,972.6	$ 3,276.0
Service cost	311.5	232.1
Interest cost	230.1	174.8
Actuarial gain	9.2	1,298.0
Benefits paid during year	(108.0)	(8.3)
Benefit obligation at end of year	5,415.4	4,972.6
Change in Plan assets:		
Fair value of Plan assets at beginning of year	3,317.7	2,826.8
Actual return on Plan assets	246.2	292.7
Employer contribution	426.3	206.5
Benefits paid during year	(108.0)	(8.3)
Fair value of Plan assets at end of year	3,882.2	3,317.7
Unfunded status	1,533.2	1,654.9
Unrecognized prior service cost	(141.6)	(155.9)
Unrecognized net loss	(1,378.4)	(1,499.0)
Accrued benefit cost	$ 13.2	$ —

Net periodic postretirement health care cost for years ending December 31, included the following components (in thousands):

	2005	2004	2003
Components of net periodic benefit cost:			
Service cost	$ 311.5	$ 232.1	$ 212.5
Interest cost	230.1	174.8	178.2
Expected return on Plan assets	(187.7)	(216.1)	(163.7)
Amortization of unrecognized net loss	85.6	15.7	30.5
Net periodic benefit cost	$ 439.5	$ 206.5	$ 257.5

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	1-Percentage-Point Increase	1-Percentage Point Decrease
Effect on total of service and interest cost components	$ 53.2	$ 76.4
Effect on postretirement benefit obligation	$545.1	$475.9

Assumptions used in accounting for the Post-Retirement Health Care Plan were as follows:

	2005	2004	2003
Discount rate	5.50%	5.75%	6.00%
Long-term rate of return on Plan assets	8.00%	8.00%	8.00%
Inflation benefit amount			
1999 through 2005	0.00%	0.00%	0.00%
2006 and later years	5.00%	5.00%	4.00%

The long-term rate of return on Plan assets is established based on MCV's expectations of asset returns for the investment mix in its Plan (with some reliance on historical asset returns for the Plans). The expected returns for various asset categories are blended to derive one long-term assumption.

Plan Assets. Citizens Bank has been appointed as trustee ("Trustee") of the Plan. The Trustee serves as investment consultant, with the responsibility of providing financial information and general guidance to the MCV Benefits Committee. The Trustee shall invest the assets of the Plan in the separate investment options in accordance with instructions communicated to the Trustee from time to time by the MCV Benefit Committee. The MCV Benefits Committee has the fiduciary and investment selection responsibility for the Plan. The MCV Benefits Committee consists of MCV Officers (excluding the President and Chief Executive Officer).

The MCV has a target allocation of 80% equities and 20% debt instruments. These investments emphasis total growth return, with a moderate risk level. The MCV Benefits Committee reviews the performance of the Plan investments quarterly, based on a long-term investment horizon and applicable benchmarks, with rebalancing of the investment portfolio, at the discretion of the MCV Benefits Committee.

MCV's Plan's weighted-average asset allocations, by asset category are as follows as of December 31:

Asset Category:	2005	2004
Cash and cash equivalents	8%	1%
Fixed income	16%	19%
Equity securities	76%	80%
Total	100%	100%

Contributions. MCV expects to contribute approximately $.4 million to the Plan in 2006.

Retirement and Savings Plans

MCV sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, MCV makes contributions to the plan of either five or ten percent of an employee's eligible annual compensation dependent upon the employee's age. MCV also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee's savings up to a maximum level. In 2005, 2004 and 2003, MCV contributed $1.2 million, $1.4 million and $1.3 million, respectively under these plans.

MCV has also maintained an Employee Excess Benefit Plan for contributions to the defined contribution and 401(k) plans, which exceed the annual federal limits. Due to a change in law, the Internal Revenue Service established a special election period for employees to elect distribution of funds from accounts such as this. During the fourth quarter of 2005, all MCV participants in the Employee Excess Benefit Plan elected to take distribution of their funds, which totaled $.2 million. Upon the withdrawal of all funds from the plan, MCV terminated the Employee Excess Benefit Plan.

Supplemental Retirement Benefits

MCV provides supplemental retirement, postretirement health care and excess benefit plans for key management. These plans are not qualified plans under the Internal Revenue Code; therefore, earnings of the trusts maintained by MCV to fund these plans are taxable to the Partners and trust assets are included in the assets of MCV. During the fourth quarter of 2005, some MCV officers, to the extent they were vested in such plans, elected distributions totaling $.6 million from these supplemental retirement plans.

(11) PARTNERS' EQUITY AND RELATED PARTY TRANSACTIONS

The following table summarizes the nature and amount of each of MCV's Partner's equity interest, interest in profits and losses of MCV at December 31, 2005, and the nature and amount of related party transactions or agreements that existed with the Partners or affiliates as of December 31, 2005, 2004 and 2003, and for each of the twelve month periods ended December 31 (in thousands).

Beneficial Owner, Equity Partner, Type of Partner and Nature of Related Party	Equity Interest	Interest	Related Party Transactions and Agreements	2005	2004	2003
CMS Energy Company						
CMS Midland, Inc.	$ 784	49.0%	Power purchase agreements	$372,739	$601,535	$513,774
General Partner; wholly-owned subsidiary of Consumers Energy Company			Purchases under gas transportation agreements	9,354	9,349	14,294
			Purchases under spot gas agreements	—	—	663
			Purchases under gas supply agreements	—	—	2,330
			Gas storage agreement	2,563	2,563	2,563
			Land lease/easement agreements	600	600	600
			Accounts receivable	26,365	50,364	40,373
			Accounts payable	1,053	1,031	1,025
			Sales under spot gas agreements	—	—	3,260
El Paso Corporation	$ (5,121)	18.1%				
Source Midland Limited Partnership ("SMLP") General Partner; owned by subsidiaries of El Paso Corporation			Purchase under gas transportation agreements	12,002	12,334	13,023
			Purchases under spot gas agreement	—	—	610
			Purchases under gas supply agreement	132,887	70,000	54,308
			Gas agency agreement	136	264	238
			Deferred reservation charges under gas purchase agreement	1,576	3,152	4,728
			Accounts payable	14,924	10,997	5,751
			Sales under spot gas agreements	—	—	3,474
			Gas supplier funds on deposit	44,353	—	—
			Letter of credit provided to MCV	385,700	184,000	—
El Paso Midland, Inc. ("El Paso Midland") General Partner; wholly-owned subsidiary of El Paso Corporation	(3,073)	10.9	See related party activity listed under SMLP.			
MEI Limited Partnership ("MEI") A General and Limited Partner; 50% interest owned by El Paso Midland, Inc. and 50% interest owned by SMLP			See related party activity listed under SMLP.			
General Partnership Interest	(2,560)	9.1				
Limited Partnership Interest	(256)	.9				
Micogen Limited Partnership ("MLP") Limited Partner, owned subsidiaries of El Paso Corporation	(1,280)	4.5	See related party activity listed under SMLP.			
Total El Paso Corporation	$(12,290)	43.5%				
The Dow Chemical Company						
The Dow Chemical Company	$ 13,107	7.5%	Steam and electric power agreement	42,873	39,055	36,207
Limited Partner			Steam purchase agreement — Dow Corning Corp (affiliate)	4,368	4,289	4,017
			Purchases under demineralized water supply agreement	6,671	8,142	6,396
			Accounts receivable	4,148	4,003	3,431
			Accounts payable	674	744	610
			Standby and backup fees	821	766	731
Alanna Corporation						
Alanna Corporation	$ 1[(1)]	.00001%	Note receivable	1	1	1
Limited Partner; wholly-owned subsidiary of Alanna Holdings Corporation						
TOTAL PARTNERS' EQUITY	$ 1,602	100.0%				

Footnotes to Partners' Equity and Related Party Transactions

(1) Alanna's capital stock is pledged to secure MCV's obligation under the lease and other overall lease transaction documents.

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2005

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement.

2.A	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (including the form of Assumption Agreement to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.1 to our Form 8-K filed December 15, 2003)
2.B	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the form of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.2 to our Form 8-K filed December 15, 2003); Amendment No. 1 to Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company, dated as of April 19, 2004 (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (Exhibit 2.1 to our Form 8-K filed April 21, 2004); Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003 (Exhibit 2.3 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (Exhibit 2.4 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement, dated as of January 14, 2005, by and among Enterprise GP Holdings, L.P., Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso Corporation and GulfTerra GP Holding Company (Exhibit 2.B.1 to our 2004 Form 10-K)
3.A	Second Amended and Restated Certificate of Incorporation (included in Exhibit 3.A to our Current Report on Form 8-K filed May 31, 2005)
3.B	By-Laws effective as of February 14, 2006 (Exhibit 3.B to our Current Report on Form 8-K filed February 16, 2006.)
4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4.A to our 2004 Form 10-K)
4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (included in Exhibit 3.A to our Current Report on Form 8-K filed May 31, 2005)

4.C	Registration Rights Agreement, dated April 15, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 4.A to our Current Report on Form 8-K filed April 15, 2005)
4.D	Registration Rights Agreement dated as of December 28, 2005 among El Paso Corporation, Goldman Sachs & Co. and Citigroup Global Markets Inc. (Exhibit 10.A to our Current Report on Form 8-K filed January 4, 2006)
4.E	Tenth Supplemental Indenture dated as of December 28, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee. (Exhibit 4.A to our Current Report on Form 8-K filed January 4, 2006)
10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004); Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004)
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Guarantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004)
+10.C	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our 2003 Form 10-K)
+10.D	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.G to our 2004 Form 10-K); Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2004 Form 10-K); Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q)
+10.E	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.H.1 to our 2003 Form 10-K)
+10.F	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I to our 2004 Form 10-K); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.1 to our 2004 Form 10-K); Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.2 to our 2004 Form 10-K)
+10.G	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.I.1 to our 2003 Second Quarter Form 10-Q)

+10.H	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.K.1 to our 2003 Form 10-K)
+10.I	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.K to our 2001 Form 10-K); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.K.1 to our 2002 Form 10-K); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q); Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.L.1 to our 2004 Form 10-K)
*+10.I.1	Amendment No. 4 to the Supplemental Benefits Plan effective as of December 31, 2004
+10.J	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.L.1 to our 2002 Form 10-K)
+10.K	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.N to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2003 Third Quarter Form 10-Q)
+10.L	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K)
+10.M	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our 2003 Form 10-K)
+10.N	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.P.1 to our 2002 Form 10-K)
+10.O	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.R to our 2004 Form 10-K)
+10.P	Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.S to our 2004 Form 10-K); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q)

+10.Q	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed February 11, 2002); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.T.1 to our 2002 Form 10-K)
+10.R	El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q); Amendment No. 1 effective as of June 6, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.AA.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.V.1 to our 2003 Form 10-K)
+10.S	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Amendment No. 2 to Supplement No. 1 effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 3 to Supplement No. 1 effective as of September 2, 2003 (Exhibit 10.Z.1 to our 2003 Third Quarter Form 10-Q); Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003 (Exhibit 10.W.1 to our 2003 Form 10-K); Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004 (Exhibit 10.W.1 to our 2003 Form 10-K)
*+10.S.1	Supplement No. 2 dated April 1, 2005 to the Severance Pay Plan Amended and Restated effective as of October 1, 2002
+10.T	Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott. (Exhibit 10.VV to our 2003 Third Quarter Form 10-Q)
+10.U	Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.U to our 2003 Third Quarter Form 10-Q)
+10.V	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K)
+10.W	Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart (Exhibit 10.CC to our 2003 Form 10-K)
+10.X	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.FF to our 2002 Form 10-K)
*+10.Y	Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto.
+10.Z	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2003 Third Quarter Form 10-Q)

10.AA	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to our 2003 Second Quarter Form 10-Q)
10.BB	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our 2003 Form 10-K)
10.CC	Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles (Exhibit 10.II to our 2003 Second Quarter Form 10-Q)
10.DD	Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004, and terminated as described in our Form 8-K filed December 3, 2004)
10.EE	Purchase Agreement dated April 11, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 10.A to our Form 8-K filed April 15, 2005)
+10.FF	Agreement and General Release dated May 4, 2005, by and between El Paso Corporation and John W. Somerhalder II (Exhibit 10.A to our Form 8-K filed May 4, 2005)
+10.GG	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors (Exhibit 10.A to our Form 8-K filed on May 31, 2005).
+10.HH	El Paso Corporation 2005 Omnibus Incentive Compensation Plan (Exhibit 10.B to our Form 8-K filed on May 31, 2005).
*+10.HH.1	Amendment No. 1 to the 2005 Omnibus Incentive Compensation Plan effective as of December 2, 2005
+10.II	El Paso Corporation Employee Stock Purchase Plan, Amended and Restated Effective as of July 1, 2005. (Exhibit 10.E to our 2005 Second Quarter Form 10-Q)

10.JJ	Credit Agreement among El Paso Corporation and El Paso Production Oil & Gas USA, L.P., as Borrowers, Fortis Capital Corp., as Administrative Agent, Arranger and Bookrunner, dated as of November 3, 2005 (Exhibit 10.A to our Form 8-K filed on November 4, 2005); First Amendment, Consent and Waiver Agreement, dated as of December 20, 2005, among El Paso Corporation and El Paso Production Oil & Gas USA, L.P., as Borrowers, Fortis Capital Corp., as Administrative Agent for the Lenders, and the several Lenders party from time to time thereto (Exhibit 10.B to our Form 8-K filed on January 4, 2006)
*+10.KK	2005 Supplemental Benefits Plan effective as of January 1, 2005
12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
21	Subsidiaries of El Paso Corporation
*23.A	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Houston)
*23.B	Consent of Independent Registered Public Accounting Firm PricewaterhouseCoopers LLP (Detroit)
*23.C	Consent of Ryder Scott Company, L.P.
*31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.B	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Undertaking

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 3rd day of March, 2006.

EL PASO CORPORATION

By /s/ DOUGLAS L. FOSHEE

Douglas L. Foshee
President and Chief Executive Officer

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

Signature	Title	Date
/s/ DOUGLAS L. FOSHEE Douglas L. Foshee	President, Chief Executive Officer and Director (Principal Executive Officer)	March 3, 2006
/s/ D. MARK LELAND D. Mark Leland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 3, 2006
/s/ JOHN R. SULT John R. Sult	Senior Vice President and Controller (Principal Accounting Officer)	March 3, 2006
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Chairman of the Board	March 3, 2006
/s/ JUAN CARLOS BRANIFF Juan Carlos Braniff	Director	March 3, 2006
/s/ JAMES L. DUNLAP James L. Dunlap	Director	March 3, 2006
/s/ ROBERT W. GOLDMAN Robert W. Goldman	Director	March 3, 2006
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	March 3, 2006
/s/ THOMAS R. HIX Thomas R. Hix	Director	March 3, 2006
/s/ WILLIAM H. JOYCE William H. Joyce	Director	March 3, 2006

Signature	Title	Date
/s/ FERRELL P. MCCLEAN Ferrell P. McClean	Director	March 3, 2006
/s/ J. MICHAEL TALBERT J. Michael Talbert	Director	March 3, 2006
/s/ ROBERT F. VAGT Robert F. Vagt	Director	March 3, 2006
/s/ JOHN L. WHITMIRE John L. Whitmire	Director	March 3, 2006
/s/ JOE B. WYATT Joe B. Wyatt	Director	March 3, 2006