EL PASO CORP/DE
Form 10-K
February 28, 2008

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007

OR

o **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 þ No o.

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 o No þ.

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 þ No o.

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. o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 29, 2007 computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date: $12,068,373,398.

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 22, 2008: 700,784,034

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 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2008.

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

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

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PART I

ITEM 1. BUSINESS

Business and Strategy

We are an energy company, originally founded in 1928 in El Paso, Texas that primarily operates in the natural gas transmission and exploration and production sectors of the energy industry. Our purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner.

Natural Gas Transmission. We own or have interests in North America s largest interstate pipeline system with approximately 42,000 miles of pipe that connect North America s major natural gas producing basins to its major consuming markets. We also provide approximately 230 Bcf of storage capacity and have an LNG receiving terminal and related facilities in Elba Island, Georgia with 806 MMcf of daily base load sendout capacity. 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. Our focus is to enhance the value of our transmission business by successfully executing on our backlog of committed expansion projects in the United States and Mexico and developing new growth projects in our market and supply areas.

Exploration and Production. Our exploration and production business is currently focused on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we held an estimated 2.9 Tcfe of proved natural gas and oil reserves, not including our equity share in the proved reserves of an unconsolidated affiliate of 0.2 Tcfe. In this business, we are focused on growing our reserve base through disciplined capital allocation and portfolio management, cost control and marketing our natural gas and oil production at optimal prices while managing associated price risks.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have Marketing and Power 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 a further discussion of our business segments, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through four separate, wholly owned pipeline systems, three majority-owned systems and three partially owned systems. These systems connect the nation s principal natural gas supply regions to the five largest consuming regions in the United States: the Gulf Coast, California, the northeast, the southwest and the southeast. We also have access to systems in Canada and assets in Mexico. Our Pipelines segment also includes our ownership of storage capacity through our transmission systems, two underground storage facilities and our LNG terminal and related facilities.

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, and other 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.

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Our strategy is to enhance the value of our transmission and storage business by:

- Successfully executing on our backlog of committed expansion projects;
- Developing new growth projects in our market and supply areas;
- Recontracting or contracting available or expiring capacity;
- Focusing on efficiency and synergies across our systems;
- Ensuring the safety of our pipeline systems and assets; and
- Providing outstanding customer service.

In November 2007, we formed El Paso Pipeline Partners, L.P., our master limited partnership (MLP). We contributed our Wyoming Interstate system and 10 percent general partner interests in each of Southern Natural Gas and Colorado Interstate Gas to the MLP. Our ownership interest in the MLP at December 31, 2007 consists of a two percent general partner interest and a 64.8 percent limited partner interest.

The tables below provide more information on our pipeline systems:

		As of December 31, 2007						
Transmission System	Supply and Market Region	Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[(1)] 2007	2006 (BBtu/d)	2005
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.	100	13,700	7,069	92	4,880	4,534	4,443
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian, Anadarko basins and via interconnects the Rocky Mountains to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650[(2)]	44	4,189	4,179	4,053
		100	400	400[(4)]		458	461	161

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.						
Cheyenne Plains Gas Pipeline (CPG) (3)	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	861	735	583	433

(1) Includes throughput transported on behalf of affiliates.

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

(3) Completed in 2005

(4) Reflects east to west flow capacity

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Transmission System	Supply and Market Region	As of December 31, 2007 Ownership Interest (Percent)	Miles of Pipeline[1]	Design Capacity[1] (MMcf/d)	Storage Capacity[1] (Bcf)	Average Throughput[1] 2007 (BBtu/d)	2006	2005
Southern Natural Gas (SNG)	Extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including, the metropolitan areas of Atlanta and Birmingham.	97	7,600	3,665	60	2,345	2,167	1,984
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.	97	4,000	3,048	29	2,339	2,008	1,902
Wyoming Interstate (WIC)[2]	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	67	800	2,721		2,071	1,914	1,572
Florida Gas Transmission[3] (FGT)	Extends from South Texas to South Florida.	50	4,881	2,100		2,056	2,018	1,916

Samalayuca Pipeline and Gloria a Dios Compression Station[4]	Extends from U.S.-Mexico border to the state of Chihuahua, Mexico.	50	23	460	462	442	423
San Fernando Pipeline[4]	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	951

(1) Includes throughput transported on behalf of affiliates and represents the systems totals and are not adjusted for our ownership interest.

(2) Includes the recently completed Kanda expansion project placed in service in January 2008.

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

(4) We have a 50 percent equity interest in Gasoductos de Chihuahua, which owns these systems.

In December 2007, we placed the LPG Burgos pipeline in service. This 117 mile pipeline, in which we own 50%, transports liquified petroleum gas and extends from Pemex s Burgos complex to the Monterrey market in the state of Nuevo Leoń, Mexico. The system has a design capacity of 30 million barrels/day and in 2007 we transported an average of 30 million barrels/day.

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As of December 31, 2007, we had the following FERC approved pipeline expansion projects on our systems. For a further discussion of other backlog expansion projects, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Project	Existing System	Capacity (MMcf/d)	Description	Anticipated Completion or In-Service Date
Essex Middlesex Project	TGP	80	To construct 7.8 miles of 24-inch pipeline connecting our Beverly-Salem line to the DOMAC line in Essex and Middlesex Counties, Massachusetts	November 2008
Medicine Bow Expansion	WIC	330	To construct a new 24,930 horsepower compression facility which increases capacity from the Powder River Basin in northeast Wyoming to the WIC mainline near the Cheyenne Hub	July 2008
Cheyenne Plains Expansion	CPG	70	To construct a new compression facility comprised of 10,310 horsepower at the Kirk Compressor Station in Yuma County, Colorado	July 2008
Cypress Phase II	SNG	114	To add 10,350 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	May 2008
Cypress Phase III	SNG	161	To add 20,700 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	January 2011
Southeast Supply Header (Phase I)	SNG	140	To construct 115 miles of pipeline to the western portion of our system and provide access through pipeline interconnects to several supply basins	June 2008

Intrastate Transmission Systems

CIG has a 50 percent interest in WYCO Development, L.L.C. (WYCO). WYCO owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to Public Service Company of Colorado s (PSCo) Fort St. Vrain electric generation plant. WYCO also owns a compressor station on our WIC system s Medicine Bow lateral in Wyoming and leases these pipeline and compression facilities to PSCo and WIC, respectively, under long-term leases. WYCO currently has two expansion projects underway, the High Plains pipeline and Totem storage expansion projects, expected to be completed in 2008 and 2009. CIG will lease these facilities and will be the operator of these projects.

Underground Natural Gas Storage Facilities

In addition to the storage along our pipeline systems, we own or have interests in the following natural gas storage facilities:

	As of December 31, 2007		
Storage Entity	**Ownership Interest (Percent)**	**Storage Capacity[1] (Bcf)**	**Location**
Bear Creek Storage	100	58	Louisiana
Young Gas Storage	48	6	Colorado

(1) Approximately 58 Bcf is contracted to affiliates. Amounts are not adjusted for our ownership interest.

LNG Facility

We own an LNG receiving terminal located on Elba Island, near Savannah, Georgia with a peak sendout capacity of 1.2 Bcf/d and a base load sendout capacity of 0.8 Bcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

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In September 2007, we received FERC approval to expand the Elba Island LNG receiving terminal and construct the Elba Express Pipeline. The expansion is anticipated to increase the peak sendout capacity of the terminal from 1.2 Bcf/d to 2.1 Bcf/d. The Elba Express Pipeline will consist of approximately 190 miles of pipeline with a total capacity of 1.2 Bcf/d, which will transport natural gas from the Elba Island LNG terminal to markets in the southeastern and eastern United States. In February 2008, we completed our acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, which is constructing a FERC approved liquefied natural gas terminal in Pascagoula, Mississippi that is expected to be placed in service in late 2011.

Markets and Competition

Our Pipelines segment provides 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 energy, wind, hydroelectric power and fuel oil.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. LNG 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 may also compete with our pipelines for transportation of gas into the 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 potential benefit is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity, increased natural gas prices and the use and availability of other fuel sources for power generation. 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 transportation contracts with natural gas 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 our firm transportation contracts as of December 31, 2007 for our wholly and majority owned systems that expire by year over the next five years and thereafter.

The following table details information related to our pipeline systems, including the customers, contracts, markets served and the competition faced by each as of December 31, 2007. Firm customers reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities and 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. Interruptible customers are customers without reserved capacity that pay usage charges based on the volume of gas they request to transport, store, inject or withdraw.

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TGP

Customer Information	Contract Information	Competition
Approximately 440 firm and interruptible customers.	Approximately 500 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in its 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.
Major Customer: National Grid USA and subsidiaries		
(722 BBtu/d)	Expire in 2009-2027.	

EPNG

Customer Information	Contract Information	Competition
Approximately 140 firm and interruptible customers	Approximately 190 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 from alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customers: Southern California Gas Company		
(187 BBtu/d)	Expires in 2009.	
(246 BBtu/d)	Expires in 2010.	
(323 BBtu/d)	Expires in 2011.	
Southwest Gas Corporation		
(11 BBtu/d)	Expires in 2008.	
(603 BBtu/d)	Expire in 2011-2015.	

MPC

Customer Information	Contract Information	Competition
Approximately 20 firm and interruptible customers	Approximately five firm transportation contracts. Weighted average remaining contract term of	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar,

	approximately eight years.	coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customer:		
EPNG		
(312 BBtu/d)	Expires in 2015.	

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CPG

Customer Information	Contract Information	Competition
Approximately 50 firm and interruptible customers	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately eight years.	CPG competes directly with other interstate pipelines serving the mid-continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets.
Major Customers:		
Oneok Energy Services Company L.P. (195 BBtu/d)	Expires in 2015.	
Encana Marketing (USA) Inc. (170 BBtu/d)	Expires in 2015.	
Anadarko Petroleum Corporation (195 BBtu/d)	Expire in 2015-2016.	
Coral Energy Resources, L.P. (125 BBtu/d)	Expires in 2019.	

SNG

Approximately 280 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately six years.	SNG faces 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 SNG s 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 sources.
Major Customers:		
Atlanta Gas Light Company (981 BBtu/d)	Expire in 2008-2015.	
Southern Company Services (418 BBtu/d)	Expire in 2010-2018.	
Alabama Gas Corporation (413 BBtu/d)	Expire in 2010-2013.	
SCANA Corporation		

(315 BBtu/d)	Expire in 2010-2019.

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CIG

Customer Information	Contract Information	Competition
Approximately 120 firm and interruptible customers	Approximately 180 firm transportation contracts. Weighted average remaining contract term of approximately five years.	CIG serves two major markets, an on- system market and an off- system market. Its on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an intrastate pipeline, an interstate 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. CIG s 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 this off-system market consists of interstate pipelines that are directly connected to its supply sources. CIG faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.
Major Customers:		
PSCo		
(187 BBtu/d)	Expires in 2008.	
(9 BBtu/d)	Expires in 2009.	
(1,106 BBtu/d)	Expire in 2012-2014.	
Williams Gas Marketing, Inc.		
(53 BBtu/d)	Expires in 2009.	
(113 BBtu/d)	Expires in 2010.	
(350 BBtu/d)	Expire in 2011-2013.	
Anadarko Petroleum Corporation		
(70 BBtu/d)	Expires in 2008.	
(12 BBtu/d)	Expires in 2009.	
(80 BBtu/d)	Expires in 2010.	
(128 BBtu/d)	Expire in 2011-2015.	

WIC[1]

Approximately 50 firm and interruptible customers	Approximately 50 firm transportation contracts. Weighted average remaining contract term of approximately ten years.	WIC competes with existing pipelines to provide transportation services from supply basins in northwest Colorado, eastern Utah and Wyoming to pipeline interconnects in northeast Colorado, and western Wyoming.

Major Customers:

Williams Gas Marketing, Inc.	
(25 BBtu/d)	Expires in 2008.
(84 BBtu/d)	Expires in 2010.
(744 BBtu/d)	Expire in 2013-2021.
Anadarko Petroleum Corporation	
(25 BBtu/d)	Expires in 2008.
(810 BBtu/d)	Expire in 2009-2022.

(1) Information included has been adjusted to reflect the completion of the Kanda expansion project placed in service in January 2008.

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Regulatory Environment. 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 interstate pipeline systems and storage facilities operates under tariffs approved by the FERC that establish rates, cost recovery mechanisms, and terms and conditions for services to our customers. Generally, the FERC s authority extends to:

- rates and charges for natural gas transportation, storage and related services;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipelines and certain 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 of the U.S. Department of Transportation, the U.S. Department of Interior and the U.S. Coast Guard. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements, and we believe that our systems are in material compliance with the applicable regulations.

Exploration and Production Segment

Our Exploration and Production segment s business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we controlled over four million net leasehold acres and our proved natural gas and oil reserves at December 31, 2007, were approximately 2.9 Tcfe, which does not include 0.2 Tcfe related to our unconsolidated investment in Four Star Oil and Gas Company (Four Star). During 2007, daily equivalent natural gas production averaged approximately 792 MMcfe/d, not including 70 MMcfe/d from our equity investment in Four Star.

We completed the acquisition of Peoples Energy Production Company (Peoples) in September 2007 for $887 million. This acquisition upgraded our portfolio of assets across a number of our operating regions, primarily the Onshore and Texas Gulf Coast regions. We are also further upgrading our portfolio by selling selected non-core properties that no longer meet our strategic objectives. In January 2008, we entered into agreements to sell $517 million of certain non-core properties in our Onshore and Texas Gulf Coast regions with estimated proved reserves of 191 Bcfe at December 31, 2007. While we do not anticipate exiting any region, our divestitures will be weighted towards the Gulf of Mexico and south Texas areas. We have a balanced portfolio of development and exploration projects, including long-lived and shorter-lived properties divided into the following regions discussed below:

United States

Onshore. The Onshore region includes operations that are primarily focused on unconventional tight gas sands, coal bed methane and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this region. During 2007, we invested $543 million on capital projects, not including acquisitions, and production averaged 374 MMcfe/d. The principal operating areas are listed below:

			2007	
Area	**Description**	**Net Acres**	**Capital Investment (In millions)**	**Average Production (MMcfe/d)**
East Texas/North Louisiana (Arklatex)	Concentrated land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. The Peoples acquisition added to our existing asset in this area most notably in Logansport, Bald Prairie, Bethany, Minden and Bethany Longstreet fields. We also have land positions in the Mississippi area, primarily in Hub Field located on the southern edge of the Mississippi Salt Basin.	113,000	$ 260	136
Black Warrior Basin	Established shallow coal bed methane producing areas of northwestern Alabama. We have high average working interests in our operated properties in addition to an average 50 percent working interest covering approximately 46,000 net acres operated by Black Warrior Methane which produces from the Brookwood Field.	171,000	$ 51	62
Mid-Continent	Primarily in Oklahoma with a focus on development projects in the Arkoma Basin where we utilize horizontal drilling in the Hartshorne Coals area, West Verdon Field, an oil producing waterflood project and shallow natural	456,000	$ 40	30

	gas production in the Hugoton field.			
Rocky Mountains (Rockies)	Primarily in Wyoming and Utah with a focus in the Powder River and Uinta basins, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with non-operated coal bed methane fields. We operate the Altamont and Bluebell processing plants and related gathering systems in Utah. We also have a non-operated working interest primarily in the Stadium Unit in the Williston Basin of North Dakota, which is undergoing secondary recovery.	357,000	$ 79	71

Area	Description	Net Acres	2007 Capital Investment (In millions)	Average Production (MMcfe/d)
Raton Basin	Primarily focused on coal bed methane production in northern New Mexico and southern Colorado where we own the minerals and have a 100 percent working interest in the Vermejo Park Ranch. We also have working interests in land positions in the San Juan Basin primarily in the Fruitland Coal and Dakota formations and the tight gas formations in Pictured Cliffs and Mesaverde.	605,000	$ 113	75

Included in our Mid-Continent operating area are our interests in 127,000 net acres in West Virginia and 122,000 net acres in the Illinois Basin, primarily in the New Albany Shale area in southwestern Indiana. We are the operator of these properties and maintain a 50 percent working interest in this large emerging area which is still under evaluation. We have drilled 34 gross wells in this basin through the end of 2007.

Texas Gulf Coast. The Texas Gulf Coast region focuses on developing and exploring for tight gas sands in south Texas and the upper Gulf Coast of Texas. In this area, we have an inventory of over 10,000 square miles of three dimensional (3D) seismic data. During 2007, we acquired producing properties and undeveloped acreage in Zapata County, Texas for $254 million. During 2007, we also invested $327 million on capital projects and production averaged 213 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2007 Capital Investment (In millions)	Average Production (MMcfe/d)
Vicksburg/Frio Trends	Includes concentrated and contiguous assets, located in south Texas, including the Jeffress and Monte Christo fields primarily in Hidalgo County, in which we have an average 90 percent working interest. We also have assets in the Alvarado and Kelsey fields and in Starr and Brooks Counties with an average working interest of over 65 percent.	83,000	$ 128	132
Upper Gulf Coast Wilcox	Located onshore Texas Gulf Coast, including Renger, Dry Hollow, Brushy Creek and Speaks fields in Lavaca County and Graceland Field, located in Colorado, County.	37,000	$ 56	32
South Texas Wilcox	Includes positions in which we have working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. We also have working interests in the Laredo and Loma Novia fields in Webb and Duval counties.	79,000	$ 143	49

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Gulf of Mexico and south Louisiana. Our Gulf of Mexico and south Louisiana operations are generally characterized by relatively high initial production rates, resulting in near-term cash flows, and high decline rates. During 2007, we invested $309 million on drilling, workover and facilities projects and production averaged 191 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2007 Capital Investment (In millions)	2007 Average Production (MMcfe/d)
Gulf of Mexico	Primarily drilling interests in 148 Blocks south of the Louisiana, Texas and Alabama shorelines focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 300 feet).	543,000	$ 281	174
South Louisiana	Primarily in Vermilion Parish and associated bays and inland waters in southwestern Louisiana covered by the Catapult 3D seismic project. We have internally processed 2,800 square miles of contiguous 3D seismic data in this project.	21,000	$ 28	17

Unconsolidated Investment in Four Star. During the third quarter of 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and the Gulf of Mexico. During 2007, our proportionate share of Four Star s daily equivalent natural gas production averaged approximately 70 MMcfe/d and at December 31, 2007, proved natural gas and oil reserves, net to our interest, were 0.2 Tcfe.

International

Brazil. Our Brazilian operations cover approximately 361,000 net acres. During 2007, we invested $220 million on capital projects in Brazil. Our operations include interests in 13 concessions located in the Espirito Santo, Potiguar and Camamu Basins, including our 35 percent working interest in the Pescada-Arabaiana Fields in the Potiguar Basin. We currently own 100 percent of the BM-CAL-4 concession which includes the Pinauna project. During 2007, we completed drilling two successful exploratory wells that extended the southern limits of the Pinauna project. We are currently assessing development options and have a process underway to potentially market up to a 50 percent non-operating interest in this concession. In addition, we completed drilling and testing two exploratory wells with Petrobras in the ES-5 Block in the Espirito Basin. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. Our production in Brazil, primarily attributable to the Pescada-Arabaiana Fields, averaged approximately 14 MMcfe/d in 2007.

Egypt. Our Egyptian operations include a 20 percent non-operated working interest in approximately 13,000 net acres in the South Feiran concession located in the Gulf of Suez. We are currently in the seismic, exploratory drilling and evaluation phases of the project. Our total funding commitment to the South Feiran concession is $3 million. In 2007, we received formal government approval and signed the concession agreement for the South Mariut Block. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We paid $3 million for the concession and agreed to a $22 million firm working commitment over three years. We are currently performing seismic evaluations on the block and expect to drill our first exploratory well in late 2008.

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Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents our estimated proved reserves by region and classification as of December 31, 2007 based on an internal reserve report as well as our 2007 production by region. 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.

	Net Proved Reserves					2007
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	(Percent)	Production (MMcfe)
Reserves and Production by Region						
United States						
Onshore	1,567,666	36,308	301	1,787,318	63%	136,701
Texas Gulf Coast	471,448	3,806	9,205	549,513	19%	77,633
Gulf of Mexico and south Louisiana	207,546	9,560	608	268,555	9%	69,671
Total United States	2,246,660	49,674	10,114	2,605,386	91%	284,005
Brazil	51,206	32,710		247,468	9%	5,237
Total	2,297,866	82,384	10,114	2,852,854	100%	289,242
Unconsolidated investment in Four Star	200,109	2,858	6,411	255,722	100%	25,470
Reserves by Classification						
United States						
Producing	1,419,621	26,578	6,679	1,619,159	62%	
Non-Producing	318,475	8,492	1,453	378,147	15%	
Undeveloped	508,564	14,604	1,982	608,080	23%	
Total proved	2,246,660	49,674	10,114	2,605,386	100%	
Brazil						
Producing	15,229	342		17,281	7%	
Non-Producing	3,414	338		5,444	2%	
Undeveloped	32,563	32,030		224,743	91%	
Total proved	51,206	32,710		247,468	100%	
Worldwide						
Producing	1,434,850	26,920	6,679	1,636,440	58%	

Non-Producing	321,889	8,830	1,453	383,591	13%
Undeveloped	541,127	46,634	1,982	832,823	29%
Total proved	2,297,866	82,384	10,114	2,852,854	100%
Unconsolidated investment in Four Star					
Producing	167,114	2,804	5,316	215,828	85%
Non-Producing	3,072		29	3,246	1%
Undeveloped	29,923	54	1,066	36,648	14%
Total Four Star	200,109	2,858	6,411	255,722	100%

Our consolidated reserves in the table above are 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 Company, L.P. (Ryder Scott), an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of 84 percent of our consolidated proved natural gas and oil reserves as of December 31, 2007. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising greater than 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 75 percent of the proved natural gas and oil reserves of Four Star, our unconsolidated affiliate. Our estimates of Four Star s proved natural gas and oil reserves are prepared by our internal reservoir engineers and do not reflect those prepared by the engineers of Four Star. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. Ryder Scott s reports are included as exhibits to this Annual Report on Form 10-K.

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 currently prescribed by the Securities and Exchange Commission (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 declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with 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

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2007, (ii) our interest in natural gas and oil wells at December 31, 2007 and (iii) our exploratory and development wells drilled during the years 2005 through 2007. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		**Undeveloped**		**Total**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Acreage						
United States						
Onshore	1,026,566	627,034	1,524,237	1,075,443	2,550,803	1,702,477
Texas Gulf Coast	173,282	119,025	114,842	80,396	288,124	199,421
Gulf of Mexico and south Louisiana	517,597	376,378	220,314	187,506	737,911	563,884
Total United States	1,717,445	1,122,437	1,859,393	1,343,345	3,576,838	2,465,782
Brazil	49,262	17,242	1,158,643	343,563	1,207,905	360,805
Egypt			1,247,064	1,195,272	1,247,064	1,195,272
Worldwide Total	1,766,707	1,139,679	4,265,100	2,882,180	6,031,807	4,021,859

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

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

In the United States, our net developed acreage is concentrated primarily in the Gulf of Mexico (33 percent), Texas (13 percent), Utah (11 percent), New Mexico (10 percent), Alabama (8 percent), Oklahoma (8 percent) and Louisiana (7 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (34 percent), the Gulf of Mexico (14 percent), Wyoming (10 percent), West Virginia (10 percent), Indiana (8 percent), Alabama (6 percent) and Texas (6 percent). Approximately 14 percent, 8 percent and 5 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 17 percent, 14 percent and 17 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 30 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or through farm-out agreements with other operators.

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	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2007	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)(3)]	Gross[(1)]	Net[(2)]
Productive Wells								
United States								
Onshore	4,901	3,627	658	495	5,559	4,122	74	61
Texas Gulf Coast	1,643	1,167			1,643	1,167	8	7
Gulf of Mexico and south Louisiana	193	127	56	31	249	158	2	1
Total	6,737	4,921	714	526	7,451	5,447	84	69
Brazil	4	1	6	2	10	3		
Worldwide Total	6,741	4,922	720	528	7,461	5,450	84	69

	Net Exploratory[(2)(4)]			Net Development[(2)(4)]		
	2007	2006	2005	2007	2006	2005
Wells Drilled						
United States						
Productive	214	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	226	112	88	239	321	283
Brazil						
Productive	3					
Dry						
Total	3					
Worldwide						
Productive	217	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	229	112	88	239	321	283

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

interest.

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

(3) At December 31, 2007, we operated 4,905 of the 5,450 net productive wells.

(4) In 2007, there was a reduction in the number of non-operated development wells drilled in the Rockies and an increase in the number of exploration wells drilled in the Raton Basin.

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.

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Net Production, Sales Prices, Transportation and Production Costs

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

	2007	2006	2005
Consolidated Volumes, Prices, and Costs per Unit:			
Net Production Volumes			
United States			
Natural gas (MMcf)	238,021	213,262	206,714
Oil, condensate and NGL (MBbls)	7,664	7,439	7,516
Total (MMcfe)	284,005	257,899	251,807
Brazil(1)			
Natural gas (MMcf)	4,295	7,140	15,578
Oil, condensate and NGL (MBbls)	157	247	620
Total (MMcfe)	5,237	8,619	19,300
Worldwide			
Natural gas (MMcf)	242,316	220,402	222,292
Oil, condensate and NGL (MBbls)	7,821	7,686	8,136
Total (MMcfe)	289,242	266,518	271,107
Total (MMcfe/d)	792	730	743
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Excluding hedges	$ 6.60	$ 6.77	$ 7.92
Including hedges	$ 7.36	$ 6.50	$ 6.69
Brazil			
Excluding hedges	$ 2.61	$ 2.61	$ 2.33
Including hedges	$ 2.61	$ 2.61	$ 2.33
Worldwide			
Excluding hedges	$ 6.53	$ 6.64	$ 7.53
Including hedges	$ 7.28	$ 6.38	$ 6.39
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Excluding hedges	$ 63.56	$ 55.95	$ 45.86
Including hedges	$ 63.56	$ 55.95	$ 45.86
Brazil			
Excluding hedges	$ 70.86	$ 64.02	$ 53.42
Including hedges	$ 41.27	$ 54.48	$ 42.42
Worldwide			
Excluding hedges	$ 63.71	$ 56.21	$ 46.43
Including hedges	$ 63.11	$ 55.90	$ 45.60
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.27	$ 0.24	$ 0.20
Oil, condensate and NGL ($/Bbl)	$ 0.83	$ 0.85	$ 0.69
Worldwide			
Natural gas ($/Mcf)	$ 0.27	$ 0.23	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 0.81	$ 0.82	$ 0.63

	2007	2006	2005
Average Production Costs ($/Mcfe)			
United States			
Lease operating costs	$ 0.86	$ 0.97	$ 0.73
Production taxes	0.31	0.28	0.27
Total production costs	$ 1.17	$ 1.25	$ 1.00
Brazil			
Lease operating costs	$ 1.63	$ 0.28	$ 0.42
Production taxes	0.51	0.53	
Total production costs	$ 2.14	$ 0.81	$ 0.42
Worldwide			
Lease operating costs	$ 0.88	$ 0.95	$ 0.72
Production taxes	0.31	0.29	0.24
Total production costs	$ 1.19	$ 1.24	$ 0.96
Unconsolidated affiliate volumes (Four Star)(2)			
Natural gas (MMcf)	19,380	18,140	6,689
Oil, condensate and NGL (MBbls)	1,015	1,087	359
Total equivalent volumes			
MMcfe	25,470	24,663	8,844
MMcfe/d	70	68	24

(1) Production volumes in Brazil decreased due to a contractual reduction of our ownership interest in the Pescada-Arabaiana Fields in early 2006.

(2) Includes our proportionate share of volumes in Four Star which was acquired in 2005. In the third quarter of 2007, we increased our ownership interest

in Four Star from
43 percent to
49 percent.

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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:

	2007	2006	2005
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 964	$ 2	$ 643
Unproved	262	34	143
Development Costs	735	738	503
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	19	23	7
Drilling	373	294	133
Asset Retirement Obligations	38	3	1
Total full cost pool expenditures	2,397	1,100	1,433
Non-full cost pool expenditures	13	8	22
Total costs incurred[1]	$ 2,410	$ 1,108	$ 1,455
Acquisition of unconsolidated investment in Four Star[2]	$ 27	$	$ 769
Brazil and Other International[1]			
Acquisition Costs:			
Proved	$	$ 2	$ 8
Unproved	5	1	1
Development Costs	26	40	6
Exploration Costs:			
Seismic acquisition and reprocessing	6	7	7
Drilling	193	46	8
Asset Retirement Obligations	7		
Total full cost pool expenditures	237	96	30
Non-full cost pool expenditures	1		
Total costs incurred	$ 238	$ 96	$ 30
Worldwide			
Acquisition Costs:			
Proved	$ 964	$ 4	$ 651
Unproved	267	35	144
Development Costs	761	778	509
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	25	30	14
Drilling	566	340	141
Asset Retirement Obligations	45	3	1

Total full cost pool expenditures	2,634	1,196	1,463
Non-full cost pool expenditures	14	8	22
Total costs incurred[1]	$ 2,648	$ 1,204	$ 1,485
Acquisition of unconsolidated investment in Four Star[2]	$ 27	$	$ 769

(1) Costs incurred for Egypt were $10 million and $4 million for the years ended December 31, 2007 and 2006.

(2) In 2005, amount includes deferred tax adjustments of $179 million 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 $200 million in 2007, $192 million in 2006 and $247 million in 2005 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

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Markets and Competition

We primarily sell our domestic natural gas and oil to third parties through our Marketing segment at spot market prices, subject to customary adjustments. 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, Brazil s state-owned energy company. We also enter into derivative contracts on our natural gas and oil production to stabilize our cash flows, reduce the risk and financial impact of downward commodity price movements and to protect the economic assumptions associated with our capital investment programs. As of December 31, 2007, our Exploration and Production segment had entered into derivative swap and option contracts on approximately 141 TBtu of our anticipated 2008 natural gas production, 16 TBtu of our total anticipated 2009-2012 natural gas production, basis swaps on 97 TBtu of our anticipated 2008 production and 15 TBtu of our total anticipated 2009-2012 natural gas production and fixed price swaps on 2,498 MBbls of our anticipated 2008 oil production. For a further discussion of these contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations. Our Marketing segment has also entered into additional production related derivative contracts as further described below.

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.

Regulatory Environment. Our natural gas and oil exploration and production activities are regulated at the federal, state and local levels, in the United States, Brazil and Egypt. These regulations include, but are not limited to, those governing 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 exploration and production operations in Brazil and Egypt are subject to environmental regulations administered by those governments, which include political subdivisions in those countries. These domestic and international laws and regulations affect 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 pollution liability exposures.

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Marketing Segment

Our Marketing 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 risk, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate various natural gas supply, transportation, power and other natural gas related contracts remaining from our legacy trading activities, which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2007, we managed the following types of contracts:

Production-Related Natural Gas and Oil Derivative Contracts. Includes options that provide price protection on our Exploration and Production segment s natural gas and oil production.

Natural Gas Transportation-Related Contracts. Includes contracts that provide transportation capacity primarily with our affiliates.

Legacy Natural Gas and Power Contracts. Includes a variety of natural gas derivative contracts and long-term supply obligations, including our Midland Cogeneration Venture (MCV) supply agreement and power contracts in the Pennsylvania-New Jersey-Maryland (PJM) region.

Production-Related Natural Gas and Oil Derivative Contracts

Our natural gas and oil contracts include options designed to provide price protection to El Paso from fluctuations in natural gas and oil prices. These contracts are in addition to contracts entered into by our Exploration and Production segment described in that segment. For a further discussion of the entirety of El Paso s production-related price risk management activities, refer to Item 7, Management s Discussion and Analysis of Financial Condition, Results of Operations and Liquidity and Capital Resources. As of December 31, 2007, our Marketing segment s contracts provided El Paso with price protection on the following quantities of future natural gas and oil production:

	2008	**2009**
Natural Gas (TBtu)		
Volumes with floor and ceiling prices		17
Oil (MBbls)		
Volumes with floor and ceiling prices	930	

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. 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, 2007:

	Affiliated Pipelines[1]	**Other Pipelines**
Daily capacity (MMBtu/d)	521,000	63,000
Expiration	2009 to 2028	2012 to 2026
Receipt points	Various	Various
Delivery points	Various	Various

(1) Primarily consists of contracts with TGP and EPNG.

Other natural gas contracts. As of December 31, 2007, we had eight significant physical natural gas contracts with power plants associated with our legacy trading activities, including MCV. We sold our equity investment in the MCV power facility in 2006. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2008 to 2028, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d.

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Power contracts. As of December 31, 2007, we had four derivative contracts that require us to swap locational differences in power prices between four power plants in the PJM eastern region with the PJM west hub. In total, these contracts require us annually to swap locational differences in power prices on approximately 4,000 GWh of power through 2008; 3,700 GWh from 2009 to 2012; 2,400 GWh for 2013 and 1,700 GWh from 2014 to 2016. Additionally, these contracts require us to provide installed capacity of approximately 71 GWh per year in the PJM power pool through 2016. While we have basis and capacity risk associated with the contracts, we do not have commodity risk associated with these contracts due to positions we put in place prior to 2007.

Markets, Competition and Regulatory Environment

Our Marketing 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 major oil and natural gas producers and their affiliates, large domestic and foreign utility companies, large local distribution companies and their affiliates, other interstate and intrastate pipelines and their affiliates, and independent energy marketers and financial institutions. Our marketing activities are subject to the regulations of among others, the FERC and the Commodity Futures Trading Commission.

Power Segment

As of December 31, 2007, our Power segment primarily included the ownership and operation of our remaining investments in international power generation facilities listed below. These facilities primarily sell power under long-term power purchase agreements with power transmission and distribution companies owned by local governments. As a result, we are subject to certain political risks related to these facilities. We continue to pursue the sale of our remaining power investments.

Project	Area	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Brazil						
Manaus[1]	Brazil	100	238	Manaus Energia	2008	Oil
Porto Velho[2]	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro[1]	Brazil	100	158	Manaus Energia	2008	Oil
Asia & Central America						
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna Power Co.	Bangladesh	74	113	BPDB	2013	Heavy Fuel Oil
Tipitapa[3]	Nicaragua	60	51	Union Fenosa	2014	Heavy Fuel Oil

(1) Ownership of these plants transferred to the power purchaser in January 2008.

(2) In the third quarter of 2007, we received an

offer from our partners to purchase this investment. For further discussion, see Item 8, Financial Statements, Note 17.

(3) In December 2007, we signed an agreement to sell this facility which is expected to close in the first half of 2008.

In addition to the international power plants above, we also have investments in two operating pipelines in South America with a total design capacity and average 2007 throughput of 1,197 MMcf/d and 1,162 BBtu/d, unadjusted for our ownership interest.

Regulatory Environment. 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 for private and foreign-owned businesses. These regulatory and legal structures are subject to change over time.

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Environmental

A description of our environmental activities is included in Part II, Item 8 Financial Statements and Supplementary Data, Note 12.

Employees

As of February 22, 2008, we had approximately 4,992 full-time employees, of which 204 employees are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of February [26], 2008, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso	2003	48
D. Mark Leland	Executive Vice President and Chief Financial Officer of El Paso	2005	46
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	51
Brent Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	46
Susan B. Ortenstone	Senior Vice President (Human Resources and Administration) of El Paso	2003	51
James C. Yardley	Executive Vice President, Pipeline Group	2005	56
James J. Cleary	President of Western Pipeline Group	2005	53
Daniel B. Martin	Senior Vice President of Pipeline Operations	2005	51

Douglas L. Foshee has been President, Chief Executive Officer and a director of El Paso since September 2003. He 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. Several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, commenced prepackaged Chapter 11 proceedings to discharge current and future asbestos and silica personal injury claims in December 2003 and an order confirming a plan of reorganization became final effective December 31, 2004. Under the plan of reorganization, all current and future asbestos and silica personal injury claims were channeled into trusts established for the benefit of asbestos and silica claimants. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer and Chairman of the Board of Nuevo Energy Company from 1997 to 2001. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Executive Officer and Chief Operating Officer. Mr. Foshee serves on the Federal Reserve Bank of Dallas, Houston Branch as a director. Mr. Foshee serves on the Board of Trustees of Rice University, where he chairs the Building and Grounds Committee in addition to serving as a member of the Council of Overseers for the Jesse H. Jones Graduate School of Management at Rice University. He is a member of the Greater Houston Partnership Board and Executive Committee and serves as Chair of the Environment Advisory Committee. In addition, Mr. Foshee serves on the Boards of Central Houston, Inc., Children s Museum of Houston, Goodwill Industries, Small Steps Nurturing Center and the Texas Business Hall of Fame Foundation. Mr. Foshee serves on the board of directors of El Paso Pipeline GP Company, L.L.C., the general partner of El Paso Pipeline Partners, L.P.

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 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 and El Paso Natural Gas Company since 1986. Mr. Leland serves on the board of directors of El Paso Pipeline GP Company, L.L.C.

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. Mr. Baker serves as Executive Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C.

Brent J. Smolik has been Executive Vice President of El Paso and President of El Paso Exploration & Production Company since November 2006. Mr. Smolik was President of ConocoPhillips Canada from April 2006 to October 2006. Prior to the Burlington Resources merger with ConocoPhillips, he was President of Burlington Resources Canada from September 2004 to March 2006. From 1990 to 2004, Mr. Smolik worked in various engineering management and executive capacities for Burlington Resources Inc.

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. Ms. Ortenstone serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C.

James C. Yardley has been Executive Vice President of El Paso with responsibility for the regulated pipeline business unit since August 2006. He has also served as President of Southern Natural Gas Company since May 1998 and President and Chairman of the Board of Tennessee Gas Pipeline Company since August 2006. Mr. Yardley has also been Chairman of the Board of El Paso Natural Gas Company since August 2006. He has been a member of the Management Committees of both Colorado Interstate Gas Company and Southern Natural Gas Company since their conversion to general partnerships in November 2007. Mr. Yardley served as Vice President, Marketing and Business Development for Southern Natural Gas Company from April 1994 to April 1998. Prior to that time, he worked in various capacities with Southern Natural Gas and Sonat Inc. beginning in 1978. Mr. Yardley serves as Director, President and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C.

James J. Cleary has been President of El Paso Natural Gas Company and Colorado Interstate Gas Company since January 2004. He also served as Chairman of the Board of El Paso Natural Gas Company and Colorado Interstate Gas Company from May 2005 to August 2006. From January 2001 to 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 beginning in 1979. Mr. Cleary serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C

Daniel B. Martin has been Director of Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company and Tennessee Gas Pipeline Company since May 2005. He was Director of ANR prior to its sale in February 2007. 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 Colorado Interstate Gas Company since January 2001. He was Senior Vice President of ANR Pipeline prior to its sale in February 2007. Prior to 2001, Mr. Martin worked in various capacities with Tennessee Gas Pipeline Company since 1978. Mr. Martin serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C.

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.

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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. These forward-looking statements are based on assumptions or beliefs that we believe to be reasonable; however assumed facts almost always vary from the actual results, and differences between assumed facts and actual results can be material, depending upon the circumstances. Where, based on assumptions, 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 stated expectation or belief will occur, 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), terrorist activity or acts of aggression, and other hazards. Each of these risks could result in damage to or destruction of our facilities or damages or injuries to persons and property causing us to suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our insurance coverages have material deductibles and self-insurance levels, as well as limits on our maximum recovery, and do not cover all risks. As a result, our results of operations, cash flows or financial condition 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 we transport and store is owned by third parties. The results of our transportation and storage operations are impacted by the volumes of natural gas we transport or store and the prices we are able to charge for doing so. The volume of natural gas we are able to transport and store 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, or to remarket unsubscribed capacity on our pipeline systems:

- service area competition;
- expiration or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- weather conditions that impact throughput and storage levels;
- price competition;
- drilling activity and decreased availability of conventional gas supply sources and the availability and timing of other natural gas supply sources, such as LNG;

- continued development of additional sources of gas supply that can be accessed;
- decreased natural gas demand due to various factors, including increases in prices and the availability or increased demand of alternative energy sources such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil;
- availability and cost of capital to fund ongoing maintenance and growth projects;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions including prolonged recessionary periods that might negatively impact natural gas demand and the capital markets;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands; and
- unfavorable movements in natural gas prices in certain supply and demand areas.

Certain of our systems transportation services are subject to long-term, fixed-price negotiated rate contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

It is possible that costs to perform services under negotiated rate contracts will exceed the negotiated rates. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a negotiated rate which may be above or below the FERC regulated recourse rate for that service, and that contract must be filed and accepted by FERC. These negotiated rate contracts are not generally subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between recourse rates (if higher) and negotiated rates, under current FERC policy is generally not recoverable from other shippers.

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, extended or replaced. If we are unable to extend or replace these contracts when they expire or renegotiate contract terms as favorable as the existing contracts, we could suffer a material reduction in our revenues, earnings and cash flows. 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 natural gas supply points; and
- regulatory actions.

Fluctuations in energy commodity prices could adversely affect our pipeline businesses.

Revenues generated by our transportation, storage and LNG contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and LNG. Increased prices could result in a reduction of the volumes transported by our customers, including power companies that may not dispatch natural gas-fired power plants if natural gas prices increase. 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 gas supplies to offset the natural decline from existing wells connected to our systems, which requires the development of additional oil and natural gas reserves, obtaining additional supplies from interconnecting pipelines, and the development of LNG facilities on or near 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 impact the value of under or over recoveries of retained natural 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 on a short-term basis, as well as with respect to our long-term recontracting activities. 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;
- abundance of supplies of alternative energy sources; and
- political unrest among countries producing oil and LNG.

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:

- our ability to obtain necessary approvals and permits by the FERC and other regulatory agencies on a timely basis and on terms that are acceptable to us;
- the ability to obtain continued access to sufficient capital to fund expansion projects;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes, regulations, and orders, including environmental requirements that prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire rights-of-way or land rights on a timely basis or on terms that are acceptable to us;
- our 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, contractor productivity or other factors beyond our control, that we may not be able to recover from our customers which may be material;
- the lack of future growth in natural gas supply; and
- the lack of transportation, storage or throughput commitments.

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 results of operations, cash flows or financial position.

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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;
- the availability and reliability of commodity processing, gathering and pipeline capacity;
- the level of imports of, and the price of, foreign natural gas and oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions, such as unusually warm or cold weather, and hurricanes in the Gulf of Mexico;
- market uncertainty;
- political conditions or hostilities in natural gas and oil producing regions;
- worldwide economic conditions; and
- changes in 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, 2007 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. A decline in natural gas and oil prices could result in a downward revision of our reserves and a full cost ceiling test 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 the following factors.

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 and increases in future costs 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 from other companies;

our ability to successfully integrate acquisitions;

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;

governmental action affecting the profitability of our exploration and production activities, such as increased royalty rates payable on oil and gas leases, the imposition of additional taxes on such activities or the modification or withdrawal of tax incentives in favor of exploration and development activity;

our lack of control over jointly owned properties and properties operated by others;

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 of drilling rights 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 inherently imprecise.

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 developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. We also use a ten percent discount factor for estimating the value of our future net cash flows from reserves and a one-day spot price (typically the last day of the year), each as prescribed by the SEC. This discount factor 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. Additionally, this one day spot price will not generally represent the market prices for natural gas and oil over time. 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 which will eventually result 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, if our capital resources become limited, or if our exploration, development and acquisition activities are unsuccessful, 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. Our competitors include the major and independent natural gas and oil companies, individual producers, gas marketers and major pipeline companies some of which have financial and other resources that are substantially greater than those available to us, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. In order to expand our leased land positions in intensively competitive and desirable areas, we must identify and precisely locate prospective geologic structures, identify and review any potential risks and uncertainties in these areas, and drill and successfully complete wells in a timely manner. Our future success and profitability in the production business may be negatively impacted if we are unable to identify these risks or uncertainties and 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, 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 as hedges or do not qualify as hedges, changes in commodity prices, interest rates, volatility, correlation factors and the liquidity of the market could cause our revenues and net income 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 could otherwise experience if commodity prices or interest rates were to change favorably. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital (current assets less current 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 7.

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States, including power, pipeline and exploration and production projects in Brazil, exploration and production projects in Egypt and pipeline projects in Mexico, are subject to the risks inherent in foreign operations. As a general rule, we have elected not to carry political risk insurance against these sorts of risks including:

- loss of revenue, property and equipment as a result of hazards such as wars or insurrection;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems;
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties, nationalization, and expropriation; and
- protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations.

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 and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold, including breaches of warranties, environmental expenditures, asset maintenance, tax, litigation, personal injury claims 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 amounts in the future and these amounts could be material. We have experienced substantial reductions and turnover in the workforce that previously supported the ownership and operation of such assets which could result in difficulties in managing these businesses, including a reduction in historical knowledge of the assets and businesses and in managing the liabilities retained after closing or defending any associated litigation.

Our business requires the retention and recruitment of a skilled workforce and the loss of employees could result in the failure to implement our business plans.

Our pipeline and exploration and production businesses require the retention and recruitment of a skilled workforce. If we are unable to retain and recruit employees such as engineers and other technical personnel, our business could be negatively impacted.

Risks Related to Legal and Regulatory Matters

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

We are subject to various governmental investigations by one or more of the following governmental agencies: the SEC, FERC and the U.S. Department of Transportation Office of Pipeline Safety. Although we are cooperating with the governmental agency or agencies in these investigations, the outcome of each of these investigations and the costs to the Company of responding and participating in these investigations is uncertain. The ultimate costs and sanctions, if any, that may be imposed upon us could have a material adverse effect on our business, financial condition or results of operation.

The agencies that regulate our pipeline businesses and their customers could 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 and local regulatory agencies whose actions 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 and sets authorized rates of return. The FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC had been using a proxy group of companies that included local distribution companies that are not faced with as much competition or risk as interstate pipelines. The inclusion of these lower risk companies could have created downward pressure on tariff rates when subjected to review by the FERC in future rate proceedings. Recently, the U.S. Court of Appeals for the DC Circuit issued a decision that would require the FERC, if it utilizes lower risk companies in the proxy group, to make upward adjustments to the return on equity to compensate for their lower level of risk. Pursuant to the FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed

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rate increases may be challenged by protest. A successful complaint or protest against our pipelines rates could have an adverse impact on our revenues. In addition, in July 2007, the FERC issued a proposed policy statement addressing the issue of the proxy groups it will use to decide the return on equity of natural gas pipelines. The proposed policy statement describes the FERC s intention to allow the use of master limited partnerships in proxy groups, which we and other pipelines have advocated. However, the FERC also proposed certain restrictions that would reduce the overall benefit that pipelines would receive by use of master limited partnerships in the proxy group. Through our trade association, we have filed comments on the policy and participated in a public conference on this subject.

Additionally, we formed El Paso Pipeline Partners, L.P., a master limited partnership, in 2007. The FERC currently allows publicly traded partnerships to include in their cost-of-service an income tax allowance. Any changes to FERC s treatment of income tax allowances in cost of service and to potential adjustment in a future rate case of our pipelines respective equity rates of return that underlie their recourse rates may cause their recourse rates to be set at a level that is different, and in some instances lower than the level otherwise in effect, could negatively impact our investment in El Paso Pipeline Partners, L.P.

Also, 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 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. Although we believe we have established appropriate reserves for our environmental liabilities, it is not possible for us to estimate the exact amount and timing of all future expenditures related to environmental matters and we could be required to set aside additional amounts which could significantly impact our future consolidated results of operations, cash flows or financial position. See Part I, Item 3, Legal Proceedings and Part II, Item 8, Financial Statements and Supplementary Data, Note 12.

In estimating our environmental liabilities, we face uncertainties that include:

- estimating pollution control and clean up costs, including sites where preliminary site investigation or assessments have been completed;
- discovering new sites or additional information at existing sites;
- quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- evaluating and understanding environmental laws and regulations, including their interpretation and enforcement; and
- changing environmental laws and regulations that may increase our costs.

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 which has been ratified by some of the international countries in which we have operations such as Mexico, Brazil, and Egypt. In the United States, various federal legislative proposals have been made over the last several years. It is difficult to predict the timing of enactment of any federal legislation, as well as the ultimate legislation that will be enacted. However, components of the legislation that have been proposed in the past could negatively impact our operations and financial results, including whether any of our facilities are designated as the point of regulation for GHG emissions, whether the federal legislation will expressly preempt the potentially conflicting state GHG legislation and how inter-fuel issues will be handled, including how allowances are granted and whether caps will be imposed on GHG charges.

Legislation and regulation are also in various stages of proposal, enactment, and implementation in many of the states in which we operate. This includes various initiatives of individual states and coalition of states in the northeastern portion of the United States that are members of the Regional Greenhouse Gas Initiative and seven western states that are members of the Western Climate Initiative.

Additionally, various governmental entities and environmental groups have filed lawsuits seeking to force the federal government to regulate GHG emissions and individual companies to reduce the GHG emissions from their operations. These and other suits may also result in decisions by federal agencies and state courts and other agencies that impact our operations and ability to obtain certifications and permits to construct future projects.

These legislative, regulatory, and judicial actions could result in changes to our operations and to the consumption and demand for natural gas and oil. Changes to our operations could include increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, (iii) construct new facilities, (iv) acquire allowances to authorize our GHG emissions, (v) pay any taxes related to our GHG emissions and (vi) administer and manage a GHG emissions program.

While we may be able to include some or all of any costs in our rates charged by our pipelines and in the prices at which we sell natural gas and oil, such recovery of costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

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 (see Part II, Item 8, Financial Statements and Supplementary Data, Note 12). 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 amounts in the future and these amounts could be material.

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 El Paso s senior unsecured indebtedness are below investment grade, currently rated Ba3 with a positive outlook by Moody s Investor Service (Moody s) and BB- with a positive outlook by Standard & Poor s. These ratings have increased our cost of capital and our operating costs, particularly in our marketing operations, and could impede our access to capital markets. Although we must retain greater liquidity levels to operate our business than if we had investment grade credit ratings, the simplification of our capital structure and business has reduced the amount of liquidity we maintain in the ordinary course of business. If there is significant volatility in energy commodity prices or interest rates, then these lower liquidity levels might not be adequate. In such an event, if our ability to generate or access capital becomes significantly restrained, then our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 11, for a further discussion of our debt.

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

Our debt and other financing obligations contain restrictive covenants, which become more restrictive over time, and contain cross default provisions. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, 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.

Additionally, some of our credit agreements are collateralized by our equity interests in EPNG and TGP as well as certain natural gas and oil reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to foreclose on these collateral interests.

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Adverse changes in general domestic economic conditions could adversely affect our operating results, financial condition, or liquidity.

We are subject to the risks arising from adverse changes in general domestic economic conditions including recession or economic slowdown. Recently, the direction and relative strength of the U.S. economy has been increasingly uncertain due to softness in the housing markets, rising oil prices, and difficulties in the financial services sector. If economic growth in the United States is slowed, demand growth from consumers for natural gas and oil produced and transported by us on our natural gas transportation systems may decrease which could impact our planned growth capital. Additionally, our access to capital could be impeded. Any of these events, which are beyond our control, could negatively impact our business, results of operations, financial condition, and liquidity.

We are subject to financing and interest rate risks.

Our future success, financial condition and liquidity could be adversely affected based 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;
- the unhedged portion of our exposure to 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 hydrocarbon products.

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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 12, and are incorporated herein by reference.

Fort Morgan Storage Field. CIG owns and operates an underground natural gas storage field in the vicinity of Fort Morgan, Colorado. In October 2006, the production casing in one of the field s injection and withdrawal wells failed resulting in the emergence of natural gas from the storage reservoir at the ground surface. In June 2007, CIG received a proposed Administrative Order of Consent (AOC) from the Colorado Oil and Gas Conservation Commission (Commission). In January 2008, the Commission approved the AOC with a settlement of all alleged violations with a penalty of $374,000.

Rawlins Plant Notice of Probable Violation. CIG owns and operates the Rawlins Gas Plant and Compressor Station which produces butane, propane, and natural gas liquids. Recently, CIG discovered that emissions from the loading process were emitted into the atmosphere and reported the discovery to the Wyoming Department of Environmental Quality (Department) which issued a Notice of Violation. CIG has reached an agreement with the Department to pay a total of $83,000 and to conduct a supplemental environmental program to install additional equipment which will reduce future emissions.

Natural Buttes. On May 19, 2004, the Federal Environmental Protection Agency (EPA) issued a Compliance Order (Order) to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. On July 7, 2004, the EPA issued a confidential Pre-filing Settlement Offer which contained a proposed fine of $350,000. In September 2005 the matter was referred to the U.S Department of Justice (DOJ). We have entered into a tolling agreement with the United States and have concluded settlement discussions in principle with the DOJ and the EPA, setting a penalty of $470,000, which includes $50,000 in incremental costs for a Supplemental Environmental Project. We have established a reserve for this penalty amount, and we anticipate a documented settlement in the first half of 2008.

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

None.

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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 22, 2008, we had 33,757 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

Quarterly Stock Prices. 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
2007			
Fourth Quarter	$18.37	$15.29	$0.04
Third Quarter	18.56	15.00	0.04
Second Quarter	17.43	14.41	0.04
First Quarter	15.66	13.71	0.04
2006			
Fourth Quarter	$15.84	$12.92	$0.04
Third Quarter	16.39	12.82	0.04
Second Quarter	16.00	11.85	0.04
First Quarter	13.95	11.80	0.04

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2002 as invested in (i) El Paso s common stock, (ii) the Standard & Poor s 500 Stock Index, (iii) the Standard & Poor s 500 Oil & Gas Storage & Transportation Index and (iv) our peer group identified below. The Peer Group we used for this comparison is the same group we use to compare total shareholder return relative to our performance for compensation purposes. Our peer group for 2007 included the following companies: Anadarko Petroleum Corp., Apache Corp., CenterPoint Energy Inc., Devon Energy Corp., Dominion Resources, Inc., Enbridge, Inc., Equitable Resources, Inc., NiSource, Inc., ONEOK, Inc., PG&E Corp., PPL Corp., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., Transcanada Corp. and Williams Companies, Inc. Our peer group for 2006 included the companies listed above as well as Western Gas Resources, Inc. and Kinder Morgan, Inc., but did not include Spectra Energy Corp.

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COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS

	12/02	12/03	12/04	12/05	12/06	12/07
El Paso Corporation	$100	$120.27	$155.64	$184.60	$234.61	$267.31
S&P 500 Stock Index	$100	$128.68	$142.69	$149.70	$173.34	$182.86
S&P 500 Oil & Gas Storage & Transportation Index(1)	$100	$163.09	$228.19	$301.43	$358.54	$409.59
New Peer Group	$100	$137.32	$172.32	$225.16	$254.39	$319.86
Old Peer Group	$100	$137.51	$172.76	$226.38	$256.51	$328.44

(1) The S&P 500 Oil & Gas Storage & Transportation Index was created as of May 1, 2005 and thus, historical values for this index were not available. Accordingly, we provided this comparison against a custom index which includes the companies in the Standard & Poor s 500 Oil & Gas Storage & Transportation Index, including El Paso.

(2) The annual values of each investment are based on the share price appreciation and assume cash dividend reinvestment. The calculations exclude any applicable

brokerage commissions and taxes. Cumulative total stockholder returns from each investment can be calculated from the annual values given above.

Dividends Declared. On February 7, 2008, we declared a quarterly dividend of $0.04 per share of our common stock, payable on April 1, 2008, to shareholders of record as of March 7, 2008. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

Other. 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 restrictions 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.

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ITEM 6: SELECTED FINANCIAL DATA

The following selected historical financial data as of and for the years ended December 31, 2004 to 2007 is derived from our audited consolidated financial statements for El Paso and its subsidiaries and is not necessarily indicative of results to be expected in the future. The amounts as of and for the year ended December 31, 2003, are derived from unaudited consolidated financial statements. Such amounts were adjusted to reflect the reclassification of ANR, our Michigan storage assets and our 50% interest in Great Lakes Gas Transmission as discontinued operations. The selected financial data 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.

	As of or for the Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,648	$ 4,281	$ 3,359	$ 4,783	$ 5,596
Income (loss) from continuing operations	$ 436	$ 531	$ (506)	$ (1,032)	$ (795)
Net income (loss) available to common stockholders	$ 1,073	$ 438	$ (633)	$ (947)	$ (1,883)
Basic earnings (loss) per common share from continuing operations	$ 0.57	$ 0.73	$ (0.82)	$ (1.61)	$ (1.33)
Diluted earnings (loss) per common share from continuing operations	$ 0.57	$ 0.72	$ (0.82)	$ (1.61)	$ (1.33)
Cash dividends declared per common share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Basic average common shares outstanding	696	678	646	639	597
Diluted average common shares outstanding	699	739	646	639	597
Financial Position Data:					
Total assets	$ 24,579	$ 27,261	$ 31,840	$ 31,398	$ 36,968
Long-term financing obligations, less current maturities	12,483	13,329	16,282	17,506	19,193
Minority Interest	565	31	31	367	447
Stockholders equity	5,280	4,186	3,389	3,438	4,346

Factors Affecting Trends. Prior to 2006, our financial position and operating results were substantially affected by the restructuring and realignment of our business around our core pipeline and exploration and production operations. Accordingly, we sold a substantial amount of non-core assets to reduce our long-term financing obligations resulting in a significant reduction of our revenues and net income during the years ended December 31, 2003, 2004, and 2005. We recorded net pretax charges of approximately $0.1 billion in 2005, $1.1 billion in 2004 and $1.3 billion in 2003, primarily as a result of losses and impairments of assets and equity investments, restructuring charges, and settling litigation. In 2007, we sold our ANR pipeline system and related assets and also completed the offering of common units in El Paso Pipeline Partners, L.P., our master limited partnership.

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

Overview

Our Management s Discussion and Analysis (MD&A) should be read in conjunction with our consolidated financial statements and the accompanying footnotes. MD&A includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing from the statements we make. These risks and uncertainties are discussed further beginning on page 27. Listed below is a general outline of our MD&A:

Our Business includes a summary of our business purpose and description, factors influencing profitability, a summary of our 2007 performance, an outlook for 2008 and an update of our credit profile;

Results of Operations includes a year-over-year analysis beginning on page 44 of the results of our business segments, our corporate activities and other income statement items, including trends that may impact our business in the future;

Liquidity and Capital Resources includes a general discussion beginning on page 65 of our debt obligations, available liquidity, expected 2008 cash flows, and significant factors that could impact our liquidity, as well as an overview of cash flow activity during 2007;

Off Balance Sheet Arrangements, Contractual Obligations, and Commodity-Based Derivative Contracts includes a discussion beginning on page 68 of our (i) off balance sheet arrangements, including guarantees and letters of credit, (ii) other contractual obligations, and (iii) derivative contracts used to manage the price risks associated with our natural gas and oil production and;

Critical Accounting Estimates includes a discussion beginning on page 71 of accounting estimates that involve the use of significant assumptions and/or judgments in the preparation of our financial statements.

Our Business

Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own or have interests in North America s largest interstate natural gas pipeline systems and are a large independent natural gas and oil producer focused on growing our reserve base through disciplined capital investment and portfolio management, cost control and marketing and selling our natural gas and oil production at optimal prices while managing associated price risks.

Factors Influencing Our Profitability. Our pipeline operations are rate-regulated and accordingly we generate profit based on our ability to earn a return in excess of our costs through the rates we charge our customers. Our exploration and production operations generate profits dependent on the prices for natural gas and oil and the volumes we are able to produce, among other factors. Our future profitability in each of our operating segments will be primarily influenced by the following factors:

Pipelines

- Successfully executing on our backlog of committed expansion projects and developing new growth projects in our market and supply areas;
- Contracting and recontracting pipeline capacity with our customers;
- Maintaining or obtaining approval by FERC of acceptable rates and terms of service; and
- Improving operating efficiency.

Exploration and Production

- Increasing our natural gas and oil proved reserve base and production volumes through successful drilling programs and/or acquisitions;
- Finding and producing natural gas and oil at a reasonable cost; and
- Managing price risks to optimize realized prices on our natural gas and oil production.

In addition to these factors, our future profitability will also continue to be impacted by our debt level and related interest costs, the successful resolution of our historical contingencies and completing the orderly exit of our remaining power assets, historical derivative contracts and other remaining non-core assets.

Summary of Overall Performance in 2007. The year ended December 31, 2007 marked our fifth consecutive year of improved profitability, driven primarily by a strong base of earnings and cash flow in our pipeline and exploration and production businesses as well as an interest expense reduction of approximately 20 percent. Across our pipeline system, we made progress on our backlog of committed expansion projects and created El Paso Pipeline Partners, L.P., our master limited partnership. In our exploration and production business, we experienced continued success in our worldwide exploration and drilling programs. These successes allowed us to replace our worldwide natural gas and oil reserves and move forward in high grading our portfolio to improve our cost structure. The following provides additional details of these items and other significant highlights in our core businesses in 2007:

Area of Operations	Significant Highlights
Pipelines	Completed and entered into new expansion projects resulting in a current backlog of almost $4 billion.
	Completed the sale of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for net cash proceeds of approximately $3.7 billion
	Implemented FERC approved rate case settlements for El Paso Natural Gas Company and Mojave Pipeline Company
	Completed a $575 million initial public offering of common units for El Paso Pipeline Partners, L.P., a newly formed master limited partnership to enhance the value and financial flexibility of our pipeline assets and provide a lower-cost source of capital for new pipeline growth projects
	Reached an agreement (completed February 2008) to acquire a 50 percent interest in the Gulf LNG Clean Energy project, which is constructing an LNG regasification terminal in Mississippi
Exploration and Production	Met production and cost targets established for 2007 with increased production volumes in each quarter of 2007
	High-graded our portfolio through the acquisition of Peoples for $887 million, adding proved reserves of 298 Bcfe, and progressed on our announced divestiture program
	Replaced 129% of our worldwide natural gas and oil reserves, excluding acquisitions, and 252% including acquisitions
	Achieved success in our exploration programs in Brazil
	Managed price risk through derivative contracts which, when combined with our other positions, provided higher realized commodity prices in 2007 and gives us price protection on approximately two-thirds of our planned 2008 equivalent production.

In addition, our 2007 performance was impacted by our Marketing and Power segments where we continued to reduce the size and volatility of these operations and by corporate costs incurred in conjunction with simplifying and strengthening our balance sheet. Specifically, we incurred (i) mark-to-market losses in our Marketing segment on production-related option contracts and legacy positions, including our Pennsylvania-New Jersey-Maryland (PJM) power contracts and (ii) incremental losses in our Power segment on Brazilian power investments. Additionally, in 2007, we (i) incurred debt extinguishment costs of approximately $291 million in conjunction with repurchasing or refinancing more than $5 billion of debt to strengthen our balance sheet and (ii) resolved certain legal and contractual disputes (see, Item 8, Financial Statements and Supplementary Data, Note 12).

Outlook. For 2008, we expect the current operating trends in our core pipeline and exploration and production businesses to continue with a focus on growing these businesses. For each business, we expect the following:

Pipelines We anticipate that our pipeline operations will continue to provide strong operating results based on its expansion plans, the current levels of contracted capacity, and the status of its rate and regulatory actions. In the pipeline industry, a favorable macroeconomic environment supports continued industry growth. We expect to spend significant pipeline growth capital in 2008. These expenditures should lay the foundation for future growth and the advancement of our significant backlog of committed expansion projects in our market and supply areas and in the development of significant new infrastructure opportunities. Additionally, we will continue to pursue proposed joint venture development projects that would use our incumbent pipeline infrastructure to connect supply areas to areas of high demand in the West, Northeast and Southeast. Finally, we expect to grow our MLP through organic growth opportunities, potential acquisitions, or through future asset contributions. Currently we have in excess of $2 billion in net operating losses available to us to offset any potential tax gains on future asset contributions to the MLP.

Exploration and Production We expect to continue with the momentum established in 2007 and seek to create value through a disciplined and balanced capital investment program. Our drilling programs will focus on growing reserves at reasonable finding and development costs, and growing production efficiently through active cost management. In 2008, our domestic programs will constitute approximately 80 percent of our planned capital and substantially all of our expected production. Performance of these programs will require successful integration and execution of our 2007 acquisitions and our 2008 planned divestitures. In 2008, our International capital is expected to increase approximately 50 percent over our 2007 program. Successful execution of these programs, primarily in Brazil, will require effective project management, partner relations and successful negotiations with regulatory agencies. Our future financial results will be primarily dependent on the continued successful execution of these drilling programs and favorable commodity prices to the extent our anticipated natural gas and oil production is unhedged. Based on our current derivative positions, we anticipate our 2008 hedging program will provide protection from price exposure on a substantial portion of our anticipated natural gas and oil production as previously described.

Credit Profile. Our outstanding debt was $12.8 billion at December 31, 2007. In 2007, we strengthened our credit profile as a result of several actions taken during the year including:

- Reducing debt by approximately $2.6 billion (including debt of our discontinued ANR operations) primarily with proceeds from the sale of ANR;
- Refinancing approximately $2.0 billion of the debt of our subsidiaries SNG, EPNG, and EPEP;
- Receiving upgraded senior unsecured debt ratings for El Paso of Ba3 with a positive outlook from Moody s, BB- with a positive outlook from Standard and Poor s and BB+ from Fitch Ratings and receiving investment grade senior unsecured debt ratings on our pipeline subsidiaries of Baa3 with a positive outlook from Moody s, BB with a positive outlook from Standard and Poor s and an investment grade rating of BBB- from Fitch Ratings. This improvement should provide us a lower cost of capital on planned expansions in our pipeline business;
- Restructuring the El Paso and EPEP revolving credit facilities with improved terms and total capacities of $1.5 billion and $1.0 billion, respectively; and
- Completing our pipeline MLP initial public offering in November 2007 providing us a lower cost of capital for further pipeline growth projects and entering into a $750 million revolving credit facility available to the MLP and non-recourse to El Paso.

Results of Operations

Overview

As of December 31, 2007, our core operating business segments were Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages our legacy trading activities and a Power segment that has interests in several international power plants. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets all of which are immaterial.

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

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

	2007	2006	2005
		(In millions)	
Segment			
Pipelines	$ 1,265	$ 1,187	$ 924
Exploration and Production	909	640	696
Marketing	(202)	(71)	(837)
Power	(37)	82	(89)
Field Services			285
Segment EBIT	1,935	1,838	979
Corporate and other	(283)	(88)	(521)
Consolidated EBIT	1,652	1,750	458
Interest and debt expense	(994)	(1,228)	(1,295)
Income taxes	(222)	9	331
Income (loss) from continuing operations	436	531	(506)
Discontinued operations, net of income taxes	674	(56)	(96)
Cumulative effect of accounting changes, net of income taxes			(4)
Net income (loss)	$ 1,110	$ 475	$ (606)

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 operates primarily in the United States and consists of interstate natural gas transmission, storage and LNG terminalling related services. 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 energy, wind, solar, coal and fuel oil. Our revenues from transportation, storage, LNG terminalling and related services consist of two types:

Type	Description	Percent of Total Revenues
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline systems, 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.	77
Usage and Other	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. We also earn revenues from the processing and sale of natural gas liquids and other miscellaneous sources.	23

The FERC regulates the rates we can charge our customers. These rates are generally a function of the cost of providing services to our customers, including a reasonable return on our invested capital. 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, market conditions, regulatory actions, competition, weather and declines in the creditworthiness of our customers. We also experience earnings volatility at certain pipelines when the amount of natural gas used 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, many of our customers have shifted from a traditional dependence 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.

We continue to manage our recontracting process to limit the risk of significant impacts on our revenues from expiring contracts. Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the rates allowed under our tariffs, although we discount these rates at various levels for each of our pipeline systems to remain competitive. Our existing contracts mature at various times and in varying amounts of throughput capacity. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2007. Below are the contract expiration portfolio and the associated revenue expirations for our firm transportation contracts on our wholly and majority owned systems as of December 31, 2007, including those with terms beginning in 2008 or later:

	BBtu/d	Percent of Total Contracted Capacity	Reservation Revenue (In millions)	Percent of Total Reservation Revenue
2008	1,836	8	$ 31	2
2009	2,539	11	170	9
2010	3,388	14	309	17
2011	2,755	11	152	9
2012	3,909	16	222	12
2013 and beyond	9,740	40	929	51
Total	24,167	100	$1,813	100

In November 2007, we completed an offering of common units in an MLP. We contributed 100 percent of WIC (our wholly owned interstate pipeline transportation business located primarily in Wyoming and Colorado) and 10 percent equity interests in CIG and SNG to the MLP. We have both a 2 percent general partner interest and a 64.8 percent limited partner interest in the MLP.

Summary of Operational and Financial Performance

In 2007, we continued to deliver strong financial performance across all pipelines. We placed several expansion projects in service including Phase I of the SNG Cypress project, TGP Louisiana Deepwater Link project, TGP Triple-T Extension project, TGP Northeast Connexion-New England project and Mexico LPG Burgos project and continued to make significant progress on our backlog of expansion projects. We also successfully resolved our EPNG and Mojave rate cases and restructured and renewed certain customer contracts. During 2007, we benefited from (i) higher realized rates on certain of our systems, (ii) increased throughput, and (iii) increased activity under other various interruptible services.

The level of throughput on our systems can provide evidence of the underlying long-term value of our system capacity. In 2007, increased throughput across our system was a result of broad based increases in power demand from Mexico, California, the Northeast and the Southeast based on underlying growth in electricity demand, colder weather and lower availability of hydroelectric power in the Northwest. We have also experienced higher supply related throughput as a result of our Rockies related expansions.

During 2008, we currently plan on spending $1.6 billion in capital, of which $1.2 billion will be targeted towards our backlog of expansion projects. We intend to build on the growth achieved in 2007 and currently have almost $4 billion in committed expansion projects that comprise our backlog as follows:

Project	***Anticipated In-Service Dates***	***Estimated Cost (in millions)***	***FERC Approved***
Cheyenne Plains Expansion	July 2008	$ 23	Yes
Cypress II/III	May 2008/January 2011	102	Yes
Essex-Middlesex	November 2008	76	Yes
Southeast Supply Header Phase I	June 2008	137	Yes
WIC Medicine Bow Expansion	July 2008	32	Yes
High Plains Pipeline (50%)	November 2008	98	No
Carthage Expansion	May 2009	39	No
Concord Lateral Expansion	November 2009	21	No
WIC Piceance Lateral Expansion	4th Quarter 2009	62	No
Totem Storage (50%)	July 2009	60	No
Elba Expansion III and Elba Express	2010-2013	1,093	Yes
South System III and Southeast Supply Header Phase II	2010-2012	319	No
FGT Phase VIII Expansion (50%)	2011	1,050	No
Gulf LNG Clean Energy (50%)[1]	2011	787	Yes
Total Committed Expansion Backlog		$ 3,899	

(1) Includes approximately $294 million that we paid to acquire a 50

percent interest
in this project.

Other Large Projects in Development. We also have two development projects underway, the recently announced Ruby Pipeline project and the Northeast Passage project. Combined, these projects are estimated to cost over $4 billion (over $2 billion net to our interests) with estimated in-service dates in 2011. These projects are in various phases of development, including obtaining necessary customer commitments and holding ownership discussions.

Operating Results

	2007	**2006**	**2005**
	(In millions, except volumes)		
Operating revenues	$ 2,494	$ 2,402	$ 2,171
Operating expenses	(1,383)	(1,339)	(1,392)
Operating income	1,111	1,063	779
Other income	154	124	145
EBIT	$ 1,265	$ 1,187	$ 924
Throughput volumes (BBtu/d)[1]			
TGP	4,880	4,534	4,443
EPNG and MPC	4,216	4,255	4,214
CIG, WIC and CPG	4,906	4,301	3,734
SNG	2,345	2,167	1,984
Other	50	50	50
Equity investments[2]	1,734	1,705	1,645
Total throughput	18,131	17,012	16,070

(1) Volumes exclude intrasegment activities.

(2) Represents our proportional share.

The table below and discussion that follows detail the impact on EBIT of significant events in 2007 compared with 2006 and 2006 as compared with 2005. We have also provided an outlook on events that may affect our operations in the future.

	2007 to 2006 Variance				2006 to 2005 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Reservation and usage revenues	$ 31	$	$	$ 31	$ 128	$	$	$ 128
Expansions	50	(7)	9	52	75	(9)	(10)	56
Gas not used in operations, revaluations, processing revenues and other natural gas sales	3	(16)		(13)	20	38		58
Hurricanes Katrina and Rita		12		12		(1)		(1)
Asset impairments		4	(2)	2		30		30
General and administrative expense		(10)		(10)		52		52
Depreciation expense		2		2		(19)		(19)
Operating costs (including pipeline integrity)		(25)		(25)		(32)		(32)
Bankruptcy settlements		(3)		(3)	15	3		18
Equity earnings from Citrus			19	19			(4)	(4)
Other[1]	8	(1)	4	11	(7)	(9)	(7)	(23)
Total impact on EBIT	$ 92	$ (44)	$ 30	$ 78	$ 231	$ 53	$ (21)	$ 263

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

Reservation and Usage Revenues. During the year ended December 31, 2007, our EBIT was favorably impacted by:

- an increase in throughput on our pipeline systems, primarily in the Rocky Mountains and southern regions which increased due to new supply, colder weather and increased transportation services to power plants;

- additional firm capacity sold in the south central region on our TGP system; and
- increased rates on our CIG system effective October 2006 as a result of CIG s rate settlement

Partially offsetting these favorable impacts in 2007 was the expiration of certain firm transportation contracts on our EPNG, MPC and SNG systems.

The increase in our reservation and usage revenues in 2006 compared with 2005 was primarily due to:

- the expiration of reduced EPNG tariff rates effective December 31, 2005, to certain customers under the terms of EPNG s FERC-approved system wide capacity allocation proceeding;
- an increase in EPNG s tariff rates effective January 1, 2006 as a result of its rate filing;
- the sales of additional firm capacity and higher realized rates on several of our pipeline systems in 2006; and
- increased activity on our pipeline systems under various interruptible services provided under their tariffs as a result of favorable market conditions.

Expansions. During 2007 and 2006, our reservation revenues and throughput volumes increased due to projects placed in service. Below is a discussion of our expansion projects placed in service.

Projects Placed in Service in 2007 and 2006. During 2007, we placed several expansion projects in service including Phase I of the Cypress project, the Louisiana Deepwater Link project, the Triple-T Extension project, the Northeast Connexion-New England project and the Mexico LPG Burgos project. In 2006, we placed several expansion projects in service including the Cheyenne Plains Yuma Lateral project, the Elba Island LNG expansion and the Piceance Basin project on our WIC system.

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Projects Placed in Service in 2008. In January 2008, we completed the WIC Kanda Lateral project which should increase annual revenues by approximately $25 million.

Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales. During the year ended December 31, 2007, our EBIT was unfavorably impacted by the (i) revaluation of net gas imbalances and other gas owed to our customers in our CIG and WIC systems as a result of increasing natural gas prices in 2007 versus decreasing natural gas prices in 2006 (ii) lower processing revenues and operational gas costs on our CIG system due to a decrease in processing volumes and natural gas liquids. Partially offsetting these unfavorable impacts in 2007 were higher volumes of gas not used in TGP s operations.

During 2006, higher realized prices on sales of gas not used in operations resulted in favorable impacts to our operating revenues, partially offset by lower sales volumes of natural gas not used in operations during 2006 compared to 2005. We also experienced favorable impacts to our operating expenses in 2006 due to decreases in the index prices used to value the net imbalance position on several of our pipeline systems. 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 2005 operating results. In addition, our pipelines also retained lower volumes of gas not used in operations during 2005. We anticipate that the overall activity in this area will continue to vary based on factors such as volatility in natural gas prices, the efficiency of our pipeline operations, regulatory actions and other factors.

Hurricanes Katrina and Rita. During 2007, we incurred lower operation and maintenance expenses to repair damage caused by Hurricanes Katrina and Rita as compared to 2006. In 2006, we recorded higher operation and maintenance expenses compared with 2005 as a result of unreimbursed amounts expended to repair hurricane damage. We do not anticipate that expenditures related to these hurricanes, net of related reimbursements, will materially impact our future financial results.

Asset Impairments. During 2007, we recorded a $10 million impairment of certain pipeline assets originally purchased to repair certain offshore hurricane damage following a decision not to use these assets. In addition, we recorded a loss of approximately $9 million pursuant to a FERC determination on the accounting treatment for the pending sale of certain transmission facilities. During 2006 and 2005, we impaired various pipeline development projects based on changing market conditions. In 2006, these impairments included $13 million and $3 million due to discontinuing our Continental Connector Pipeline project and the remainder of our Seafarer Project. In 2005, we recorded impairments of $18 million and $28 million due to discontinuing a portion of our Seafarer project and the entirety of our Blue Atlantic development project.

General and Administrative Expenses. During the year ended December 31, 2007, our general and administrative expenses were higher than in 2006 primarily due to increased insurance costs for wind damage on our pipeline assets located primarily in the Gulf of Mexico region. Our general and administrative costs were lower in 2006 than 2005, primarily due to a decrease in accrued benefit costs and lower allocated costs from El Paso based on the estimated level of resources devoted to the pipeline segment and the relative size of its EBIT, gross property and payroll as compared to the consolidated totals.

Depreciation Expense. Depreciation expense was higher for 2006 compared to 2005 primarily due to higher depreciation rates applied to EPNG s property, plant and equipment following its 2006 rate case.

Operating Costs (Including Pipeline Integrity). During 2007, we incurred higher operating costs than in 2006 primarily due to increased repair and maintenance costs, allowances for non-trade accounts receivable and environmental reserves. During 2006, we incurred higher costs than in 2005 primarily for repairs and maintenance and $19 million of pipeline integrity costs which we began expensing in 2006 as a result of the adoption of an accounting release issued by the FERC.

Bankruptcy Settlements. In 2007, we received $10 million to settle our bankruptcy claim against USGen New England, Inc. During 2007 and 2006, we recorded income of approximately $5 million and $18 million, net of amounts potentially owed to certain customers, related to amounts recovered from the Enron bankruptcy settlement. In February 2008, we received a portion of the bankruptcy settlement under Calpine Corporation s approved plan of reorganization. In connection with this plan, we received Calpine common stock with a market value of approximately $29 million, on which we will recognize a gain in the first quarter of 2008.

Equity Earnings from Citrus. During the year ended December 31, 2007, equity earnings on our Citrus investment increased primarily due to (i) a favorable settlement of approximately $8 million for litigation brought against Spectra LNG Sales (formerly Duke Energy LNG Sales, Inc.) for the wrongful termination of a gas supply contract; (ii) Citrus sale of a receivable for approximately $3 million related to the bankruptcy of Enron North America and (iii) favorable operating results of approximately $8 million from Florida Gas Transmission Company, a pipeline owned 100 percent by Citrus, due to higher system usage and lower operating costs.

Regulatory Matters/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 in 2008 and expect to continue operating under their existing rates. Certain other pipelines have recently completed, or are in rate proceedings or have upcoming rate actions including the following:

EPNG In August 2007, EPNG received approval of the settlement of its rate case from the FERC. The settlement provides benefits for both EPNG and its customers for a three year period ending December 31, 2008. Under the terms of the settlement, EPNG is required to file a new rate case to be effective January 1, 2009. EPNG received approval of its settlement from the FERC and refunded $115 million, with interest, in the fourth quarter of 2007. A final refund of $10 million was paid in January 2008.

MPC MPC s primary customer is EPNG. In February 2007, MPC filed with the FERC a general rate case proposing a 33 percent decrease in its base tariff rates. No new services were proposed. The new base rates were effective March 1, 2007. In December 2007, FERC approved an offer of settlement to resolve all issues in the rate case. Under the settlement, MPC has a $4 million, third party refund obligation for a previously accrued regulatory obligation.

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CIG/WIC In August 2007, CIG filed a tariff change with the FERC to modify its fuel recovery mechanism to recover all cost impacts, or flow through to shippers any revenue impacts, of fuel imbalance revaluations and related gas balance items. CIG currently experiences variability in cash flow and earnings under its fuel recovery mechanism, but its earnings variability from price fluctuations will be substantially reduced if the FERC approves the fuel tracker. This tariff filing was protested by certain shippers and the FERC suspended the effective date to March 1, 2008 subject to the similar outcome of a technical conference on the proposed tariff change which was held in November 2007. In September 2007, WIC filed a tariff change with the FERC. This tariff filing was protested by certain shippers and the FERC suspended the effective date to April 1, 2008, subject to the outcome of a technical conference on the proposed tariff change, which was held in November 2007. Comments on these proposals have been filed by various parties to the proceedings, but no further action has yet been taken by the FERC relative to these proceedings.

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Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance of this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves with the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management.

Our domestic natural gas and oil reserve portfolio blends slower decline rate, typically longer lived assets in our Onshore region with steeper decline rate and shorter lived assets in our Texas Gulf Coast, Gulf of Mexico and south Louisiana regions. We believe the combination of our assets in these domestic regions provides significant near-term cash flow while providing consistent opportunities for competitive investment returns. In addition, our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and longer term cash flows.

As part of our business strategy, we attempt to create value through a balance of drilling activities, exploration, and through acquisitions of assets and companies. For 2008, we expect our growth to occur principally through drilling activities and we will continue to evaluate acquisition and growth opportunities that are tightly focused around our core competencies and areas of competitive advantage. We believe strategic acquisitions can support our corporate objectives by:

- Re-shaping our portfolio to provide greater opportunities to achieve our long term performance goals;
- 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 our current drilling inventory.

In September 2007, we acquired Peoples, which provided an upgrade to our portfolio of assets. We are also further upgrading our portfolio by selling selected properties. In January 2008, we entered into agreements to sell $517 million of certain non-core properties in our Onshore and Texas Gulf Coast regions with estimated proved reserves of 191 Bcfe at December 31, 2007. These sales are expected to close in the first quarter of 2008. We expect upgrading our portfolio will extend the reserve life of our assets, reduce unit operation and maintenance costs, increase predictability, improve capital efficiency and expand the depth of our inventory.

In addition to executing on our strategy, the profitability and performance of our exploration and production operations can be substantially impacted by (i) changes in commodity prices, (ii) industry-wide increases in drilling and oilfield service costs, and (iii) the effect of hurricanes and other weather impacts on our daily production, operating and capital costs. To the extent possible, we attempt to mitigate these factors. As part of our risk management activities, we have entered into derivative contracts on a significant portion of our anticipated 2008 natural gas and oil production to reduce the financial impact of downward commodity price movements.

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Significant Operational Factors Affecting the Year Ended December 31, 2007

Production. Our average daily production for the year was 792 MMcfe/d (not including 70 MMcfe/d from our share of production from our equity investment in Four Star). Our production levels grew in every quarter of 2007. Below is a further analysis of our 2007 production by region (MMcfe/d):

	2007	2006	2005
United States			
Onshore	374	345	300
Texas Gulf Coast	213	187	211
Gulf of Mexico and south Louisiana	191	174	179
International			
Brazil	14	24	53
Total Consolidated	792	730	743
Four Star	70	68	24

Onshore region Our 2007 production continued to increase through capital projects where we maintained or increased production in most of our major operating areas, with the majority of growth coming from the Rockies and Arklatex areas. Our Peoples acquisition in September 2007 also contributed to production volume increases during the year.

Texas Gulf Coast region The acquisition of properties in Zapata County during the first quarter of 2007 and the success of our drilling program more than offset natural production declines and the sale of certain non-strategic south Texas properties in 2006. Our Peoples acquisition in September 2007 also contributed to production volume increases during the year.

Gulf of Mexico and south Louisiana region We began producing from development wells in the western Gulf and south Louisiana and several exploratory discoveries occurring prior to 2007. We also recovered volumes previously shut-in by hurricane damage which, when coupled with these new production sources, helped to offset natural production declines.

Brazil Production volumes decreased in 2007 due to natural production declines and a contractual reduction of our ownership interest in the Pescada-Arabaiana Fields in early 2006.

Four Star Our original ownership interest in Four Star was obtained in the Medicine Bow acquisition in August 2005. In January 2007, Four Star acquired properties that added production of approximately 5 MMcfe/d, net of our interest on the acquisition date. In the third quarter of 2007, we spent $27 million to increase our ownership interest in Four Star from 43 percent to 49 percent.

2007 Drilling Results

Onshore. We realized a 99 percent success rate on 502 gross wells drilled.

Texas Gulf Coast. We experienced a 92 percent success rate on 84 gross wells drilled.

Gulf of Mexico and south Louisiana. We drilled six successful wells and seven unsuccessful wells.

Brazil. We currently own 100 percent of the BM-CAL-4 concession in the Camamu Basin. In 2007, we completed drilling two successful exploratory wells south of the Pinauna Field in this concession that extends the southern limits of the Pinauna project. We are currently assessing development options and have a process underway to potentially market up to a 50 percent non-operating interest in this concession. In addition, we completed drilling and testing two exploratory wells with Petrobras in the ES-5 Block in the Espirito Basin. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. We are currently in negotiations with Petrobras on a unitization agreement for the development of this discovery.

Egypt. In 2007, we received formal government approval and signed the concession agreement for the South Mariut Block. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We paid $3 million for the concession and agreed to a $22 million firm working commitment over three years.

We are currently performing seismic evaluations on the block and expect to drill our first exploratory well in late 2008.

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Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil volumes. These costs are calculated on a per Mcfe basis and include total operating expenses less depreciation, depletion and amortization expense, other non-cash expense items and the cost of products and services on our income statement. In 2007, cash operating costs per unit increased to $1.88/Mcfe as compared to $1.86/Mcfe in 2006. Our operating costs increased primarily as a result of higher production taxes which increased due to higher natural gas and oil reserves, lower severance tax credits, higher marketing and other costs and higher corporate overhead allocations.

Reserve Replacement Costs/Reserve Replacement Ratio. We calculate two primary metrics, (i) a reserve replacement ratio and (ii) reserve replacement costs, to measure our ability to establish a long-term trend of adding reserves at a reasonable cost in our core asset areas. The reserve replacement ratio is an indicator of our ability to replenish annual production volumes and grow our reserves. It is important for us to economically find and develop new reserves that will more than offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves. In addition, we calculate reserve replacement costs to assess the cost of adding reserves which is ultimately included in depreciation, depletion and amortization expense. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our core asset areas at a lower cost than our competition. We calculate these metrics as follows:

Reserve replacement ratio	Sum of reserve additions(1)
	Actual production for the corresponding period
Reserve replacement costs/Mcfe	Total oil and gas capital costs(2)
	Sum of reserve additions (1)

(1) Reserve additions include proved reserves and reflect reserve revisions, extensions, discoveries and other additions and acquisitions and do not include unproved reserve quantities or proved reserve additions attributable to investments accounted for using the equity method. Amounts are derived directly from the table

presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

(2) Total oil and gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

Both the reserve replacement ratio and reserve replacement costs per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

The exploration for and the acquisition and development of natural gas and oil reserves is inherently uncertain as further discussed in Part I, Item 1A, Risk Factors, Risks Related to our Business. One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped. At December 31, 2007, proved developed reserves represent approximately 71 percent of total proved reserves. Proved developed reserves will generally begin producing within the year they are added whereas proved undeveloped reserves generally require a major future expenditure.

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The table below shows our reserve replacement costs and reserve replacement ratio for our domestic and worldwide operations for each of the years ended December 31:

	2007	2006	2005
		($/Mcfe)	
Domestic			
Reserve replacement costs, including acquisitions	$3.26	$3.92	$3.02
Reserve replacement costs, excluding acquisitions	3.22	3.94	3.98
Worldwide			
Reserve replacement costs, including acquisitions	$3.55	$4.17	$2.75
Reserve replacement costs, excluding acquisitions	3.79	4.19	3.19
		(% of Production)	
Domestic			
Reserve replacement ratio, including acquisitions	255%	109%	188%
Reserve replacement ratio, excluding acquisitions	129%	108%	79%
Worldwide			
Reserve replacement ratio, including acquisitions	252%	108%	195%
Reserve replacement ratio, excluding acquisitions	129%	107%	93%

In 2007, our domestic reserve replacement costs decreased primarily due to favorable acquisitions and finding and development costs and upward revisions in previous estimates of reserves due to higher commodity prices at December 31, 2007. We typically cite reserve replacement costs in the context of a multi-year trend, in recognition of its limitation as a single year measure, but also to demonstrate consistency and stability, which are essential to our business model. For the three year period ending December 31, 2007, our average reserve replacement costs for our domestic and worldwide operations were $3.31/Mcfe and $3.40/Mcfe, including acquisitions, and $3.64/Mcfe and $3.75/Mcfe excluding acquisitions.

Capital Expenditures. Our capital expenditures were as follows for the three years ended December 31:

	2007	2006	2005
		(in millions)	
Total oil and gas capital costs[(1)]	$ 2,589	$ 1,193	$ 1,462
Less: acquisition capital	(1,178)	(4)	(651)
Capital expenditures, excluding acquisitions	$ 1,411	$ 1,189	$ 811

(1) Total oil and gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations.

Amounts are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

Outlook for 2008

For 2008, we anticipate the following on a worldwide basis:

Average daily production volumes for the year of approximately 805 MMcfe/d to 860 MMcfe/d, which excludes approximately 65 MMcfe/d to 70 MMcfe/d from our equity investment in Four Star.

Capital expenditures, excluding acquisitions, of approximately $1.7 billion. While approximately 80% of the Company s planned 2008 capital program is allocated to its domestic program, we plan to spend approximately $350 million in international capital in 2008, primarily in our Brazil exploration and development program. As part of our domestic capital program, we will allocate a greater percentage of our capital to our Onshore and Texas Gulf Coast regions in light of our announced divestiture plans.

Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.75/Mcfe to $1.90/Mcfe for the year; and

Depreciation, depletion and amortization rate of between $2.80/Mcfe and $3.20/Mcfe.

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Price Risk Management Activities

As part of our strategy, we enter into derivative contracts on our natural gas and oil production to stabilize cash flows, to reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. 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.

The following table and discussion that follows shows, as of December 31, 2007, the contracted volumes and the minimum, maximum and average prices we will receive under these contracts when combined with the sale of the underlying hedged production:

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)					
							Texas Gulf Coast		Onshore-Raton		Rockies	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2008	33	$ 7.65	108	$ 8.00	108	$ 10.80	58	$ (0.33)	26	$ (1.13)	13	$ (1.37)
2009	5	$ 3.56							15	$ (1.00)		
2010	5	$ 3.70										
2011-2012	6	$ 3.88										
Oil												
2008	2,498	$ 88.48										

(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.

(2) Our basis swaps effectively limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. The average prices listed

above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational differences.

All of our oil fixed price swaps and 86 percent of our natural gas fixed price swaps and option contracts are designated as accounting hedges. Gains and losses associated with these natural gas contracts are deferred in accumulated other comprehensive income and will be recognized in earnings upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. With regard to our natural gas positions, approximately 7 TBtu of our fixed price swaps, 15 TBtu of our option contracts and all of our basis swaps are not designated as accounting hedges. Accordingly, changes in the fair value of these derivatives are recognized in earnings each period.

During January and February 2008, we entered into (i) 47 TBtu of options on our anticipated 2008 natural gas production with a floor price of $8.00 per MMBtu and an average ceiling price of $10.64 per MMBtu; (ii) 7 TBtu of options on our anticipated 2009 natural gas production with a floor price of $8.00 per MMBtu and a ceiling price of $11.05 per MMBtu; and (iii) 292 MBbls of fixed price swaps on our anticipated 2008 oil production at a price of $99.00 per barrel. All of these contracts were designated as accounting hedges, except for 19 TBtu of the 2008 natural gas option contracts. The total of all our positions provides price protection on approximately two-thirds of our planned 2008 equivalent production.

Additionally, the table above does not include contracts entered into by our Marketing segment as further described in that segment. For the consolidated impact of the entirety of El Paso s production-related price risk management activities on our overall liquidity, see the discussion of factors that could impact our liquidity in Liquidity and Capital Resources.

Operating Results and Variance Analysis

The tables below and the discussion that follows provide the operating results and analysis of significant variances in these results during the periods ended December 31:

	2007	2006	2005
	(In millions, except for Volumes and prices)		
Operating Revenues:			
Natural gas	$ 1,764	$ 1,406	$ 1,420
Oil, condensate and NGL	494	430	371
Other	42	18	(4)
Total operating revenues	2,300	1,854	1,787
Operating Expenses:			
Depreciation, depletion and amortization	(780)	(645)	(612)
Production costs	(344)	(331)	(261)
Cost of products and services	(92)	(87)	(47)
General and administrative expenses	(185)	(156)	(185)
Other	(13)	(10)	(11)
Total operating expenses	(1,414)	(1,229)	(1,116)
Operating income	886	625	671
Other income [(1)]	23	15	25
EBIT	$ 909	$ 640	$ 696

(1) Includes equity earnings from our investment in Four Star.

	2007	Percent Variance	2006	Percent Variance	2005
Consolidated volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	242,316	10%	220,402	(1)%	222,292
Average realized prices including hedges ($/Mcf)	$ 7.28	14%	$ 6.38	%	$ 6.39
Average realized prices excluding hedges ($/Mcf)	$ 6.53	(2)%	$ 6.64	(12)%	$ 7.53
Average transportation costs ($/Mcf)	$ 0.27	17%	$ 0.23	28%	$ 0.18
Oil, condensate and NGL					
Volumes (MBbls)	7,821	2%	7,686	(6)%	8,136
Average realized prices including hedges ($/Bbl)	$ 63.11	13%	$ 55.90	23%	$ 45.60

Average realized prices excluding hedges ($/Bbl)	$ 63.71	13%	$ 56.21	21%	$ 46.43
Average transportation costs ($/Bbl)	$ 0.81	(1)%	$ 0.82	30%	$ 0.63
Total equivalent volumes					
MMcfe	289,242	9%	266,518	(2)%	271,107
MMcfe/d	792	8%	730	(2)%	743
Production costs and other cash operating costs ($/Mcfe)					
Average lease operating costs	$ 0.88	(7)%	$ 0.95	32%	$ 0.72
Average production taxes[1]	0.31	7%	0.29	21%	0.24
Total production costs	$ 1.19	(4)%	$ 1.24	29%	$ 0.96
Average general and administrative expenses	$ 0.64	8%	$ 0.59	(13)%	$ 0.68
Average taxes, other than production and income taxes	$ 0.05	67%	$ 0.03	%	$ 0.03
Total cash operating costs	$ 1.88	1%	$ 1.86	11%	$ 1.67
Depreciation, depletion and amortization ($/Mcfe)	$ 2.70	12%	$ 2.42	7%	$ 2.26
Unconsolidated affiliate volumes (Four Star)					
Natural gas (MMcf)	19,380		18,140		6,689
Oil, condensate and NGL (MBbls)	1,015		1,087		359
Total equivalent volumes					
MMcfe	25,470		24,663		8,844
MMcfe/d	70		68		24

(1) Production taxes include ad valorem and severance taxes.

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Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Our EBIT for 2007 increased $269 million as compared to 2006. The table below lists the significant variances in our operating results in 2007 as compared to 2006:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Lower natural gas prices in 2007	$ (26)	$	$	$ (26)
Impact of hedges	239			239
Higher volumes in 2007	145			145
Oil, Condensate and NGL Revenue				
Higher oil, condensate, and NGL prices in 2007	59			59
Impact of hedges	(4)			(4)
Higher volumes in 2007	7			7
Other Revenue				
Change in fair value of derivatives not designated as accounting hedges	47			47
Other	(21)			(21)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2007		(82)		(82)
Higher production volumes in 2007		(52)		(52)
Production Costs				
Higher lease operating costs in 2007		(1)		(1)
Higher production taxes in 2007		(12)		(12)
General and Administrative Expenses		(29)		(29)
Other				
Earnings from investment in Four Star			2	2
Other		(9)	6	(3)
Total Variances	$ 446	$ (185)	$ 8	$ 269

Operating revenues. During 2007, revenues increased compared with 2006 due to higher realized natural gas and oil prices, including the effects of our hedging program. Realized gains on hedging transactions were $177 million during 2007, as compared to losses of $58 million in 2006. During 2007, we also benefited from an increase in production volumes in all domestic regions over 2006.

Other revenue. During 2007, we recognized mark-to-market gains of $7 million compared to losses of $40 million in 2006 related to the change in fair value of derivatives not designated as hedges, including a portion of our oil and natural gas fixed price swaps, option contracts and basis swaps.

Depreciation, depletion and amortization expense. During 2007, our depletion rate increased as compared to the same periods in 2006 as a result of the Peoples and Zapata County, Texas property acquisitions and higher finding and development costs.

Production costs. Our production taxes increased during 2007 as compared to 2006 primarily due to higher natural gas and oil revenues and lower severance tax credits in 2007.

General and administrative expenses. Our general and administrative expenses increased during 2007 as compared to 2006 primarily due to higher marketing and other costs previously included in our Marketing segment and higher corporate overhead allocations.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Our EBIT for 2006 decreased $56 million as compared to 2005. The table below lists the significant variances in our operating results in 2006 as compared to 2005:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Lower natural gas prices in 2006	$ (197)	$	$	$ (197)
Impact of hedges	197			197
Lower production volumes in 2006	(14)			(14)
Oil, Condensate and NGL Revenue				
Higher oil, condensate, and NGL prices in 2006	75			75
Impact of hedges	5			5
Lower volumes in 2006	(21)			(21)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2006		(51)		(51)
Lower production volumes in 2006		10		10
Production Costs				
Higher lease operating costs in 2006		(58)		(58)
Higher production taxes in 2006		(12)		(12)
General and Administrative Expenses		29		29
Other				
Change in fair value of oil and basis swaps	(31)			(31)
Earnings from investment in Four Star			(9)	(9)
Processing plants	41	(29)		12
Other	12	(2)	(1)	9
Total Variances	$ 67	$ (113)	$ (10)	$ (56)

Operating revenues. Natural gas revenues decreased by approximately $197 million as natural gas prices were not as strong in 2006 as compared to 2005. However, we experienced lower hedging program losses for 2006 of $58 million compared to losses of $260 million for 2005. Realized oil, condensate and NGL prices increased in 2006 when compared to 2005.

Our production volumes benefited in 2006 from our acquisitions in 2005. However, overall production volumes decreased in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions due to natural declines, and the sale of certain non-strategic south Texas properties with average production of 5 MMcfe/d in 2006. Also, our Gulf of Mexico and south Louisiana region production continued to be impacted in 2006 by Hurricanes Katrina and Rita, which occurred in late 2005. Our production volumes in Brazil decreased due to the contractual reduction of our ownership interest in the Pescada-Arabaiana Fields in 2006.

Depreciation, depletion and amortization expense. During 2006, we experienced higher depletion rates as compared to 2005 primarily as a result of higher finding and development costs and the cost of acquired reserves. However, lower production volumes in 2006 partially offset the impact of these higher depletion rates.

Production costs. In 2006, our lease operating costs increased as compared to 2005 in all regions as a result of inflation in fuel costs, power and other services. In our Onshore region, additional increases were due to increased subsurface maintenance and our acquisition of Medicine Bow. In the Gulf of Mexico region, additional increases were due to hurricane repairs not recoverable through insurance. Additionally, production taxes increased as a result of lower tax credits in Texas taken in 2006 compared to 2005.

General and administrative expenses. Our general and administrative expenses decreased during 2006 as compared to the same period in 2005, primarily due to lower corporate overhead allocations.

Other. During 2006, we recorded a loss of approximately $40 million of the fair value of our derivatives not designated as hedges as compared to a $9 million loss in 2005. In 2006, our EBIT was also unfavorably impacted by earnings from Four Star due to lower natural gas prices. Our EBIT was favorably impacted by operations at our processing plants and insurance recoveries resulting from Hurricane Ivan, among other items.

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Marketing Segment

Our Marketing 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. In addition, we continue to manage and liquidate remaining legacy natural gas supply, transportation, power and other natural gas contracts entered into prior to the deterioration of the energy trading environment in 2002. Any future liquidations may impact our cash flows and financial results. However, we may not liquidate certain of these remaining legacy contracts before their expiration if (i) they are 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. The table that follows provides a description of our remaining contracts and our remaining exposure on these contracts. All mark-to-market contracts are subject to interest rate exposure as the interest rates used in determining the fair market values are subject to change from period to period.

Contract Type	Description	Remaining Exposure
Mark-to-Market		
Production-related natural gas and oil derivatives	Option contracts with various floor and ceiling prices	Changes in natural gas and oil prices.
Power contracts	Pennsylvania-New Jersey-Maryland (PJM) basis and installed capacity positions.	Changes in regional power prices and installed capacity prices.
	PJM commodity contracts.	Counterparty credit as commodity positions are hedged at PJM west hub.
Other natural gas contracts	Fixed-price and index-priced, physical delivery contracts; fixed-for-float swaps.	Counterparty credit as commodity positions were flattened as a result of transactions entered into in 2006 and 2007.
Accrual		
Transportation-related natural gas contracts	Pipeline capacity contracts.	Locational differences in natural gas prices which could affect our ability to use the capacity to recover demand charges. Exposure to future losses reduced significantly due to releasing or assigning capacity related to Alliance and other pipelines in 2006 and 2007.
Long-term gas supply obligations	Primarily four contracts with delivery obligations up to 0.3 Bcf/d with expiration dates ranging from 2011 to 2028.	Index-priced contracts are exposed to locational changes in natural gas prices.

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Operating Results

Overview. Over the past three years, our operating results and year-to-year comparability have been impacted by significant commodity and other market fluctuations, changes in the composition of our portfolio (and related effort to manage our portfolio) based on actions taken to reduce exposure and exit our legacy trading activities. The tables below and discussions that follow provide further information about these events, our overall operating results and analysis by significant contract type for our Marketing segment during each of the three years ended December 31:

	2007	2006	2005
		(In millions)	
Revenue by Significant Contract Type:			
Production-Related Natural Gas and Oil Derivative Contracts			
Changes in fair value of options and swaps	$ (89)	$ 269	$ (436)
Contracts Related to Legacy Trading Operations:			
Natural gas transportation-related natural gas contracts:			
Demand charges	(98)	(125)	(156)
Settlements, net of termination payments	76	(110)	121
Changes in fair value of other natural gas derivative contracts	(31)	(163)	39
Changes in fair value of power contracts	(77)	71	(386)
Other			22
Total revenues	(219)	(58)	(796)
Operating expenses	(15)	(33)	(59)
Operating loss	(234)	(91)	(855)
Other income, net	32	20	18
EBIT	$ (202)	$ (71)	$ (837)

Our 2007 results were primarily driven by mark-to-market losses on our production-related option contracts and legacy natural gas and power positions (including our PJM contracts). These losses were partially offset by $23 million of other income recognized upon the sale of our investment in the NYMEX and $28 million of EBIT ($23 million of revenues and $5 million of other income) related to the settlement of outstanding California power price disputes.

Our 2006 and 2005 financial results were significantly impacted by:

- mark-to-market gains and losses on our production-related natural gas and oil derivative contracts
- the divestiture in 2006 of a significant portion of our natural gas portfolio
- a termination payment in 2006 of $188 million to a third party to assume our Alliance transportation capacity obligations effective November 1, 2007
- losses in 2006 based on changes in the fair value of our other natural gas derivative contracts including approximately $133 million of previously unrecorded losses on our Midland Cogeneration Venture (MCV) supply agreement in conjunction with the sale of our interest in that facility
- the divestitures in 2005 of our Cordova tolling agreement and a majority of the contracts in our power portfolio

Production-related Natural Gas and Oil Derivative Contracts

Options contracts. Our production-related natural gas and oil derivative contracts are designed to provide protection to El Paso against changes in natural gas and oil prices. These are in addition to those derivative contracts entered into by our Exploration and Production segment which are further described in the discussion of that segment above. For the consolidated impact of all of El Paso s production-related price risk management activities, refer to our Liquidity and Capital Resources discussion. The fair value of our derivative contracts is impacted by changes in commodity prices from period-to-period and is marked-to-market in our results. Listed below are the volumes and average prices associated with our production-related derivative contracts as of December 31, 2007:

	Floors[1]		Ceilings[1]	
	Volumes	Average Price	Volumes	Average Price
Natural Gas 2009	17	$ 6.00	17	$ 8.75
Oil 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.

We experience volatility in our financial results based on changes in the fair value of our option contracts which generally move in the opposite direction from changes in forward commodity prices. During 2007 and 2005, increases in forward commodity prices reduced the fair value of our option contracts resulting in a loss. During 2006, decreases in forward commodity prices increased the fair value of our option contracts resulting in a gain. We received approximately $45 million and $59 million in 2007 and 2006 and paid $40 million in 2005 on contracts that settled during those periods.

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. As of December 31, 2007, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. The recovery of demand charges related to our transportation contracts and therefore the profitability of these contracts, is dependent upon our ability to use or remarket 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. In November, 2007, our future earnings exposure relating to our transportation contracts was reduced with the transfer of our Alliance capacity to a third party. As of December 31, 2007, our contracts require us to pay demand charges of approximately $41 million in 2008 and an average of $24 million between 2009 and 2012. Our transportation contracts are accounted for on an accrual basis and impact our revenues as delivery or service under the contracts occurs. The following table is a summary of demand charges (in millions) and percentage of recovery of these charges for each of the three years ended December 31:

	2007	**2006**	**2005**
Alliance:			
Demand charges	$ 56	$64	$65
Recovery[(1)]	48%	59%	93%
Other:			
Demand charges	$ 42	$61	$91
Recovery	100%	68%	69%

(1) Excluded from this amount is the $188 million we paid in 2006 in conjunction with the sale of this contract.

Other natural gas derivative contracts. In 2006 we divested or entered into transactions to divest of a substantial portion of these natural gas contracts, which substantially reduced our exposure to price movements on these contracts. However, we maintain contracts with third parties that require us to purchase or deliver natural gas primarily at market prices including a gas supply contract with the MCV power facility. Additionally, we recognized a $49 million gain in 2006 associated with the assignment of certain natural gas derivative contracts to supply natural gas in the southeastern U.S. In 2006 in conjunction with sale of the MCV facility in our Power segment, we recorded a cumulative mark to market loss of approximately $133 million which had not been previously recognized due to our affiliated ownership interest.

Power Contracts. By the end of 2005, we had substantially eliminated exposure to power price movements on our legacy power contracts. Prior to eliminating this price risk, we experienced significant net decreases in the fair value of these contracts based primarily on changes in natural gas and power prices as well as differences in locational power prices.

The remaining exposure in our power portfolio is related to several contracts that require us to swap locational differences in power prices between power plants in the Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub, and provide installed capacity in the PJM power pool through 2016. The fair value of these contracts decreased by approximately $100 million in 2007 and increased by approximately $70 million in 2006. The losses in 2007 were primarily the result of increasing installed capacity prices in the PJM region, while the gains in 2006 primarily related to locational price differences in these regions. By the end of 2006, we had eliminated the commodity price risk associated with these contracts. In 2007, the PJM Independent System Operator began conducting periodic auctions to set prices for providing installed capacity to customers in the PJM power pool. The fair value of our power contracts is impacted by changes in installed capacity prices, which are based in part on the result of these auctions. The results of future auctions, and other potential developments with our contracts and the PJM marketplace may result in future volatility in our operating results. We estimate that a ten percent change in auction prices from the most recent capacity price of $174/MW-day would change the fair value of our contracts by approximately $5 million.

Other. During 2005, a bankruptcy court entered an order allowing Mohawk River Funding III s, our subsidiary s, bankruptcy claims with USGen New England. We received payment on these claims and recognized a gain of $17 million in 2005 in other income related to this settlement.

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Power Segment

Overview. Our Power segment consists of assets in Brazil, Asia and Central America. We continue to pursue the sales of these remaining power investments. As of December 31, 2007, our remaining investment, guarantees and letters of credit related to projects in this segment totaled approximately $548 million, which consisted of approximately $514 million in equity investments and notes receivable and approximately $34 million in financial guarantees and letters of credit as follows:

Area	**Amount (In millions)**
Brazil	
Porto Velho	$ 275
Manaus & Rio Negro	57
Pipeline projects	138
Asia & Central America	78
Total investment, guarantees and letters of credit	$ 548

Operating Results. In 2007, our results were primarily negatively impacted by impairment losses in Brazil related to the Porto Velho, Manaus and Rio Negro projects. Prior to 2006, our financial results in this segment were significantly impacted by impairments, net of gains and losses on sale, on both domestic and other international power facilities. A further discussion of these events and other factors impacting our results in this segment for the three years ended December 31 are listed below:

	2007	**2006**	**2005**
		(In millions)	
EBIT by Area:			
Brazil			
Impairments	$ (72)	$	$
Other EBIT from operations	51	64	55
Other International Power			
Impairments, net of gains (losses) on sales	(1)	(12)	(45)
Other EBIT from operations	(1)	(1)	34
Domestic Power			
Impairments, net of gains (losses) on sales		10	(167)
Favorable resolution of bankruptcy claim			53
Gain on sale of available-for-sale investment (1)		47	40
Other(2)	(14)	(26)	(59)
EBIT	$ (37)	$ 82	$ (89)

(1) Related to the disposition of our shares of International Commodity Exchange in 2005 and 2006.

(2) Consists of indirect expenses and general and administrative costs and includes $27 million of impairments and losses in 2005.

Brazil. In 2007, our Porto Velho project, Manaus and Rio Negro projects and our other Brazilian operations (including our interests in the Bolivia-to-Brazil and Argentina-to-Chile pipelines) generated EBIT losses of $27 million, EBIT losses of $6 million and EBIT of $12 million, respectively. Our 2007 results included charges of $57 million for Porto Velho and $15 million for Manaus and Rio Negro based on adverse developments at these projects. In 2006 and 2005, EBIT was $41 million and $23 million for Porto Velho, $17 million and $19 million for Manaus and Rio Negro and $6 million and $13 million for our other Brazilian operations. For a further discussion of matters that have impacted or could impact our Brazilian investments, see Item 8, Financial Statements, Note 17.

Other International Power. During 2005, we recorded impairments of $176 million which were significantly offset by gains on sales of assets of $131 million based on the value received or expected to be received upon closing the sales of our assets in Asia and Central America. Our results were also impacted by our decision to not recognize earnings from assets we planned to sell based on our inability to realize those earnings through their expected selling price. We did not recognize earnings of approximately $10 million, $26 million and $30 million for the years ended 2007, 2006 and 2005. We continue to pursue the sale of our remaining investments in Asia and Central America and until these sales are completed, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in additional impairments of our investments.

Domestic Power. In 2006, we completed the disposition of our domestic power business. We recorded a gain in this segment of approximately $10 million, primarily related to the sale of our investment in MCV. The disposition of our investment in MCV in 2006 also impacted certain contracts and the financial results in our Marketing segment. Prior to 2006 we sold our interests in several domestic power facilities and restructured power contracts, resulting in significant impairments and substantially lower earnings from these operations. In addition, we recorded our proportionate share of MCV s losses based on their impairment of the plant assets in 2005.

Field Services

Prior to January 1, 2006, we had a Field Services segment. During 2005, we generated EBIT of $285 million which, among other items, was primarily due to a gain of $183 million on the sale of our general partner and limited partner interests in Enterprise Products Partners, L.P. and a gain of $111 million on the sale of our Javelina processing operations.

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 activities for each of the three years ended December 31:

	2007	2006	2005
		(In millions)	
Early extinguishment/exchange of debt	$ (291)	$ (26)	$ (29)
Foreign currency fluctuations on Euro-denominated debt	(8)	(20)	36
Change in litigation, insurance and other reserves	23	(71)	(490)
Lease termination			(27)
Other	(7)	29	(11)
Total EBIT	$ (283)	$ (88)	$ (521)

Extinguishment of Debt. During 2007, we incurred losses of $291 million in conjunction with repurchasing or refinancing more than $5 billion of debt. This amount included $86 million related to repurchasing EPEP s $1.2 billion notes. For further information on our debt, see Item 8, Financial Statements, Note 11.

Litigation, Insurance, and Other Reserves. During 2007, we recorded a gain of approximately $77 million on the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business. For a further discussion of this matter, see Item 8, Financial Statements, Note 12. We also have a number of pending litigation matters against us. In all of these matters, we evaluate each lawsuit and claim as to its merits and our defenses. Adverse rulings and unfavorable settlements against us related to these matters impacted our results in 2007 and 2006 and may further impact our future results. In 2005, 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, in 2005 we incurred charges of $72 million primarily related to the final prepayment of the Western Energy Settlement and additional charges related to increased premiums from a mutual insurance company in which we participate, based primarily on the impact of several hurricanes in 2005.

Interest and Debt Expense

Our interest and debt expense was approximately $1.0 billion, $1.2 billion and $1.3 billion during the years ended December 31, 2007, 2006 and 2005.

Our total interest and debt expense has decreased over the past three years primarily due to the retirements of debt and other financing obligations, net of issuances. See Part II, Item 8, Financial Statements and Supplementary Data, Note 11, for a further discussion.

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Income Taxes

	Years Ended December 31,		
	2007	2006	2005
	(In millions)		
Income taxes from continuing operations	$222	$(9)	$(331)
Effective tax rate	34%	(2)%	40%

In 2007, our overall effective tax rate on continuing operations for each period differed from the statutory rate due primarily to earnings from unconsolidated affiliates where we anticipate receiving dividends that qualify for the dividend received deduction. In 2006 and 2005, we recorded $159 million and $58 million of tax benefits based primarily on the conclusion of IRS audits. In 2006, the audits of The Coastal Corporation s 1998-2000 tax years and El Paso s 2001 and 2002 tax years were concluded which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. In 2005, we finalized The Coastal Corporation s IRS tax audits for years prior to 1998.

For a discussion of our effective tax rates and other tax matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 4.

Discontinued Operations

Our discontinued operations in the years presented primarily include our ANR pipeline and related assets, our gathering and processing operations in south Louisiana and certain international power operations. For the year ended December 31, 2007, income from discontinued operations was $674 million primarily a result of the gain on the sale of ANR and related operations of $648 million, net of income taxes of $354 million. For the years ended December 31, 2006 and 2005, we had losses from our discontinued operations of $56 million and $96 million. Our 2006 loss of $56 million was primarily a result of recording approximately $188 million of deferred taxes upon agreeing to sell the stock of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission. Prior to our decision to sell, we were only required to record deferred taxes on individual assets and liabilities and a portion of our investment in the stock of one of these companies. Our 2005 loss of $96 million was primarily a result of impairments of our discontinued international power operations partially offset by income from ANR and related assets and a gain on the sale of our south Louisiana operations. All of these items are further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 2.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8, Financial Statements and Supplementary Data, Note 12.

Liquidity and Capital Resources

Sources and Uses of Cash. Our primary sources of cash are cash flow from operations and amounts available to us under revolving credit facilities. On occasion and as conditions warrant, we may also generate funds through capital market activities and proceeds from asset sales. Our primary uses of cash are funding the capital expenditure programs of our pipeline and exploration and production operations, meeting operating needs, and repaying debt when due or repurchasing certain debt obligations when conditions warrant.

Overview of Cash Flow Activities. During 2007, we generated positive operating cash flow of approximately $1.8 billion, primarily as a result of cash provided by our pipeline and exploration and production operations. We also sold our ANR pipeline and related assets which generated $3.7 billion of net proceeds. We utilized our operating cash flow and cash from the sale of ANR to fund maintenance and growth projects in our pipeline and exploration and production operations and to reduce our debt obligations (see Item 8, Financial Statements, Note 11). In November 2007, we issued units in a master limited partnership generating gross proceeds of $575 million from the initial public offering. For the year ended December 31, 2007 and 2006, our cash flows from continuing operations are summarized as follows:

	2007	2006
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Income from continuing operations	$ 0.4	$ 0.5
Loss on debt extinguishment	0.3	
Other income adjustments	1.4	1.1
Change in other assets and liabilities	(0.3)	0.2
Total cash flow from operations	$ 1.8	$ 1.8
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.1	$ 0.7
Net change in restricted cash and other		0.2
	0.1	0.9
Continuing financing activities		
Net proceeds from the issuance of long-term debt	6.6	0.4
Contribution from discontinued operations	3.4	0.2
Net proceeds from the issuance of common stock		0.5
Net proceeds from the issuance of minority interest in consolidated subsidiary	0.5	
	10.5	1.1
Total other cash inflows	$ 10.6	$ 2.0
Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 2.5	$ 2.2
Cash paid for acquisitions, net of cash acquired	1.2	

	3.7	2.2
Continuing financing activities		
Payments to retire long-term debt and other financing obligations	8.9	3.0
Dividends and other	0.1	0.2
	9.0	3.2
Total cash outflows	$ 12.7	$ 5.4
Net change in cash	$ (0.3)	$ (1.6)

The contribution of cash generated from our discontinued operations reflected above consists of the following for the year ended December 31, 2007:

	(In billions)
Proceeds from sale of ANR and related assets	$ 3.7
Payments to retire ANR debt obligations	(0.3)
Contribution from discontinued operations	$ 3.4

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Credit Profile. The substantial repayment of debt obligations during 2007 improved our credit profile and our credit ratings. In March 2007, Moody s Investor Services upgraded our pipeline subsidiaries senior unsecured debt rating to an investment grade rating of Baa3 and upgraded El Paso s senior unsecured debt rating to Ba3 while maintaining a positive outlook. Additionally, in March 2007, (i) Standard and Poor s upgraded our pipeline subsidiaries senior unsecured debt rating to BB and upgraded El Paso s senior unsecured debt rating to BB- maintaining a positive outlook and (ii) Fitch Ratings initiated coverage on El Paso assigning a rating of BB+ on our senior unsecured debt and an investment grade rating of BBB- to our pipeline subsidiaries senior unsecured debt. This improvement should provide us a lower cost of capital on our planned expansion projects in our pipeline business.

In addition, during 2007 we restructured our El Paso and El Paso Exploration & Production revolving credit agreements with improved terms and pricing and refinanced approximately $2.0 billion of EPEP, SNG and EPNG debt providing us with a lower cost of debt with less restrictive covenants. We also established a pipeline MLP which provides us a lower cost of capital and allows us to better compete for expansion projects of our pipeline business. We expect to grow our MLP through organic growth and accretive acquisitions from third parties, El Paso or both.

Liquidity/Cash Flow Outlook. For 2008, we expect to continue to generate positive operating cash flows. We also anticipate generating over $1 billion upon the completion of asset divestitures in conjunction with high grading our exploration and production asset portfolio and completing remaining international power asset sales. We anticipate using cash proceeds from our exploration and production divestitures to repay debt in the first quarter of 2008. We expect to use our cash from operations and remaining sales proceeds primarily for working capital requirements and for expected capital expenditures. We have approximately $0.3 billion of debt that matures through December 31, 2008 that we currently intend on refinancing. Additionally, we previously announced our intention to repurchase debt of approximately $0.5 billion of CIG and SNG. In December 2007, we repurchased approximately $0.2 billion and anticipate completing the remaining $0.3 billion of repurchases in the first half of 2008.

Our planned cash capital expenditures for 2008 are as follows:

	Total (In billions)
Pipelines	
Maintenance	$ 0.4
Growth	1.2
Exploration and Production	1.7
Corporate and other[(1)]	0.1
	$ 3.4

(1) Relates primarily to building renovations at our corporate facilities.

Factors That Could Impact Our Future Liquidity. Based on the simplification of our capital structure and our businesses, we have reduced the amount of liquidity needed in the normal course of business. However, our liquidity needs could increase or decrease based on certain factors described below and others listed in Part 1, Item 1A, Risk Factors. These factors include, but are not limited to, the completion of planned asset sales, the effect that our debt level, and below investment grade credit ratings could have on our cost of capital, our ability to access capital markets, and operating costs (primarily margining requirements related to our derivative positions) and adverse changes in domestic economic conditions, including recession or economic slowdown, which could also impact the demand for our natural gas transportation services and ultimately impact our planned growth capital.

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Price Risk Management Activities and Cash Margining Requirements. Our Exploration and Production and Marketing segments have derivative contracts that provide price protection on a portion of our anticipated natural gas and oil production. The following table shows the contracted volumes and the minimum, maximum and average cash prices that we will receive under our derivative contracts when combined with the sale of the underlying production as of December 31, 2007. These cash prices may differ from the income impacts of our derivative contracts, depending on whether the contracts are designated as hedges for accounting purposes or not. The individual segment discussions provide additional information on the income impacts of our derivative contracts.

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)					
							Texas Gulf Coast		Onshore-Raton		Rockies	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2008	33	$ 7.65	108	$ 8.00	108	$10.80	58	$(0.33)	26	$(1.13)	13	$(1.37)
2009	5	$ 3.56	17	$ 6.00	17	$ 8.75			15	$(1.00)		
2010	5	$ 3.70										
2011-2012	6	$ 3.88										
Oil												
2008	2,498	$88.48	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.

(2) Our basis swaps effectively limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the

NYMEX price to lock-in these locational price differences.

During January and February 2008, we entered into (i) 47 TBtu of options on our anticipated 2008 natural gas production with a floor price of $8.00 per MMBtu and an average ceiling price of $10.64 per MMBtu; (ii) 7 TBtu of options on anticipated 2009 natural gas production with a floor price of $8.00 per MMBtu and a ceiling price of $11.05 per MMBtu; and (iii) 292 MBbls of fixed price swaps on our anticipated 2008 oil production at a price of $99.00 per barrel.

We currently post letters of credit for the required margin on most of our derivative contracts. Historically, we were required to post cash margin deposits for these amounts. During 2007, approximately $90 million of posted cash margin deposits were returned to us resulting from settlement of the related contracts and changes in commodity prices. In 2008, based on current prices, we expect approximately $0.2 billion of the total of $1.0 billion in collateral outstanding at December 31, 2007 to be returned to us, primarily in the form of letters of credit.

Depending on changes in commodity prices, we could be required to post additional margin or may recover margin earlier than anticipated. Based on our derivative positions at December 31, 2007, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements of approximately $14 million which consists of $5 million for transactions that settle in 2008, $3 million for transactions that settle in 2009 and $6 million for transactions that settle in 2010 and thereafter. We have a $250 million unsecured contingent letter of credit facility available to us if the average NYMEX gas price strip for the remaining calendar months through March 2008 reaches $11.75 per MMBtu, which is further described in Item 8, Financial Statements, Note 11.

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Off-Balance Sheet Arrangements

We enter into a variety of financing arrangements and contractual obligations, some of which are referred to as off-balance sheet arrangements. These include guarantees, letters of credit and other interests in variable interest entities.

Guarantees

We are involved in joint ventures and other ownership arrangements that sometimes require additional financial support in the form 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.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $785 million, for which we are indemnified by third parties for $15 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 11. Included in the above maximum stated value is approximately $438 million related to indemnification arrangements associated with the sale of ANR and related operations and approximately $119 million related to tax matters, related interest and other indemnifications and guarantees arising out of the sale of our Macae power facility. As of December 31, 2007, we have recorded obligations of $51 million related to our guarantees and indemnification arrangements, of which $8 million is related to ANR and related assets and Macae. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not limit the amount of future payments due to the uncertainty of these exposures.

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 paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $379 million associated with our estimated exposure under this matter as of December 31, 2007. For a further discussion of this matter, see Part II, Item 8 Financial Statements and Supplementary Data, Notes 12 and 13.

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, 2007, we had outstanding letters of credit of approximately $1.3 billion, including $1.0 billion of letters of credit securing our recorded obligations related to price risk management activities.

Interests in Variable Interest Entities

We have interests in several 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. As of December 31, 2007, we do not consolidate six variable interest entities since we are not the primary beneficiary of the variable interest entity s operations. For additional information regarding our interests in those entities, see Part II, Item 8 Financial Statements and Supplementary Data, Note 17, Investments in, Earnings from and Transactions with Unconsolidated Affiliates.

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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 long-term debt, liabilities from commodity-based derivative contracts and other accrued liabilities, while other obligations, such as demand charges under transportation and storage commitments, operating leases and capital commitments, are not reflected on our balance sheet. The following table and discussion that follows summarizes our contractual cash obligations as of December 31, 2007, for each of the periods presented (all amounts are undiscounted except liabilities from commodity-based derivative contracts):

	Due in Less than 1 Year	Due in 1 to 3 Years	Due in 4 to 5 Years	Thereafter	Total
		(In millions)			
Long-term financing obligations:					
Principal	$ 331	$ 1,346	$ 2,718	$ 8,452	$ 12,847
Interest	914	1,677	1,490	8,051	12,132
Liabilities from commodity-based derivative contracts	267	431	319	178	1,195
Other contractual liabilities	56	68	26	54	204
Operating leases	14	23	14	29	80
Other contractual commitments and purchase obligations:					
Transportation and storage	26	43	26	100	195
Other	561	91	31	26	709
Total contractual obligations	$ 2,169	$ 3,679	$ 4,624	$ 16,890	$ 27,362

Long Term Financing Obligations (Principal and Interest). Debt obligations included represent stated maturities unless otherwise puttable to us prior to their stated maturity date. Contractual interest payments are shown through the stated maturity date of the related debt. For a further discussion of our debt obligations see Item 8, Financial Statements and Supplementary Data, Note 11.

Liabilities from Commodity-Based Derivative Contracts. These amounts only include the fair value of our price risk management liabilities. The fair value of our commodity-based price risk management assets of $303 million as of December 31, 2007 is not reflected in these amounts. We have also excluded margin and other deposits held associated with these contracts from these amounts. For a further discussion of our commodity-based derivative contracts, see the discussion of commodity-based derivative contracts below.

Other Contractual Liabilities. Included in this amount are contractual, environmental and other obligations included in other current and non-current liabilities in our balance sheet. We have excluded from these amounts expected contributions to our pension and other postretirement benefit plans, because these expected contributions are not contractually required. For further information on our expected contributions to our pension and post retirement benefit plans, see Part II, Item 8, Financial Statements and Supplementary Data, Note 13. Also excluded are potential amounts due under an indemnification of a former subsidiary for benefits being paid to a closed group of retirees, for which we have a liability of approximately $379 million related to the litigation associated with this matter as of December 31, 2007. We have also excluded from these amounts liabilities for unrecognized tax benefits of $157 million as of December 31, 2007, since we cannot reasonably estimate the time frame over which those amounts may be resolved.

Operating Leases. For a further discussion of these obligations, see Part II, Item 8 Financial Statements and Supplementary Data, Note 12.

Other Contractual Commitments and Purchase Obligations. 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. Included are the following:

Transportation and Storage Commitments. Included in these amounts are commitments for demand charges for firm access to natural gas transportation and storage capacity.

Other Commitments. Included in these amounts are 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. We have excluded asset retirement obligations and reserves for litigation, environmental remediation and self-insurance claims as these liabilities are not contractually fixed as to timing and amount.

Commodity-Based Derivative Contracts. We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. In the tables below, derivatives designated as hedges primarily consist of options and swaps used to hedge natural gas production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps and other natural gas and power purchase and supply contracts. The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2007:

	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						
Non-exchange traded positions						
Assets	$ 65	$	$	$	$	$ 65
Liabilities	(19)	(42)	(27)			(88)
Total derivatives designated as hedges	46	(42)	(27)			(23)
Other commodity-based derivatives						
Exchange-traded positions[1]						
Liabilities		(15)				(15)
Non-exchange traded positions						
Assets	48	72	82	29	7	238
Liabilities	(248)	(374)	(292)	(174)	(4)	(1,092)
Total other commodity-based derivatives	(200)	(317)	(210)	(145)	3	(869)
Total commodity-based derivatives	$ (154)	$ (359)	$ (237)	$ (145)	$ 3	$ (892)

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

Clearinghouse.

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2007 and 2006:

	Derivatives Designated as Hedges	Other Commodity-Based Derivatives (In millions)	Total Commodity-Based Derivatives
Fair value of contracts outstanding at December 31, 2005	$ (653)	$ (763)	$ (1,416)
Fair value of contract settlements during the period[1]	204	38	242
Change in fair value of contracts	514	154	668
Assignment of contracts		36	36
Other commodity-based derivatives subsequently designated as hedges	(16)	16	
Reclassification of derivatives that no longer qualify as hedges	6	(6)	
Option premiums paid[2]	6	69	75
Net change in contracts outstanding during the period	714	307	1,021
Fair value of contracts outstanding at December 31, 2006	61	(456)	(395)
Fair value of contract settlements during the period[1]	(109)	(224)	(333)
Change in fair value of contracts	4	(211)	(207)
Assignment of contracts		18	18
Option premiums paid[2]	21	4	25
Net change in contracts outstanding during the period	(84)	(413)	(497)
Fair value of contracts outstanding at December 31, 2007	$ (23)	$ (869)	$ (892)

(1) In 2006 includes derivative contracts sold/terminated. In 2007, we settled derivative assets of approximately $381 million by applying the related cash margin we held against amounts due to us under those contracts.

(2) Amounts are net of premiums received.

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, including amounts received from the sale of option 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. In 2006, the change in fair value also includes a loss on natural gas supply agreements related to MCV upon the sale of our interest in this facility.

Assignment of Contracts. In 2006, we sold or entered into offsetting derivative transactions to eliminate the price risk associated with a substantial portion of our remaining historical natural gas derivatives. We paid proceeds of approximately $32 million related to this transaction.

Designation and Reclassifications of Hedges. During 2006, we removed the hedging designation on certain derivative contracts where we experienced decreases in the related anticipated hedged production volumes in Brazil. Also, during 2006 we designated certain existing other commodity-based derivatives as hedges of our anticipated 2007 natural gas production.

Critical Accounting Estimates

Our significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting estimates and to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expenses and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those that require difficult, complex, or subjective judgment necessary in accounting for inherently uncertain matters and those that could significantly influence our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. We have discussed the development and selection of the following critical accounting estimates and related disclosures with the Audit Committee of our Board of Directors.

Accounting for Natural Gas and Oil Producing Activities. Our estimates of proved reserves reflect quantities of natural gas, oil and NGL which geological and engineering data demonstrate, with reasonable certainty, will be recoverable in future years from known reservoirs under existing economic conditions. 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 complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. Our reserve estimates are developed internally by a reserve reporting group which is separate from our operations group and reviewed by internal committees and internal auditors. In addition, a third-party reservoir engineering firm, which is appointed by and reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of a significant portion of our proved reserves. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising greater than 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value.

As of December 31, 2007, of our total proved reserves, 29 percent were undeveloped and 13 percent were developed, but non-producing. The data for a given field may 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 increase 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, including salaries, benefits and other internal costs directly related to these finding activities. Capitalized costs are maintained in full cost pools 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. 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.

Natural gas and oil properties include unproved property costs that are excluded from costs being depleted. These unproved property costs include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs in investments in unproved properties and major development projects in which we own a direct interest. We exclude these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if exclusion from the full-cost pool continues to be appropriate. If costs are determined to be impaired, the amount of any impairment is transferred to the full cost pool if a reserve base exists or is expensed if a reserve base has not yet been created. Impairments transferred to the full cost pool increase the depletion rate for that country.

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, discounted at 10 percent, net of related income tax effects, plus the lower of cost or fair market value of unproved properties. We utilize end of period spot prices when calculating future net revenues unless those prices result in a ceiling test charge in which case we evaluate price recoveries subsequent to the end of the period. If the 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. Higher proved reserves can reduce the likelihood of ceiling test impairments. We had no ceiling test charges in 2007, 2006 and 2005.

The price used in the ceiling test calculation 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 a write-down. A decrease in commodity prices of 10 percent from the price levels at December 31, 2007 would not have resulted in a ceiling test charge in 2007.

Accounting for Legal and Environmental Reserves, Guarantees and Indemnifications. 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 an 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, 2007, we had accrued approximately $460 million for legal matters, net of related insurance receivables, which includes approximately $379 million associated with an indemnity for certain retiree benefit payments, which is further discussed below. We have accrued $260 million for environmental matters. Our environmental estimates range from approximately $260 million to approximately $470 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 ($18 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($242 million to $452 million) and the lower end of the expected range has been accrued.

We also have guarantee and indemnification agreements related to various joint ventures and other ownership arrangements that require us to assess our potential exposure. This exposure can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $785 million, for which we are indemnified by third parties for $15 million. As of December 31, 2007, we have recorded obligations of $51 million related to our guarantees and indemnification arrangements. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments under the agreement due to the uncertainty of these exposures. For further information, see *Off Balance Sheet Arrangements* above.

Accounting for Pension and Other Postretirement Benefits. We reflect an asset or liability for our pension and other postretirement benefit plans based on their over funded or under funded status. As of December 31, 2007, our combined pension plans were over funded by $513 million and our combined other postretirement benefit plans were under funded by $110 million. Our pension and other postretirement benefit assets and liabilities 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 matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities. We also compare our discount rates to the Citigroup Pension Discount Curve and to the yields of several high-quality bond indices with maturity profiles similar to the average duration of our benefit obligations, including the Moody s Aa Average Corporate Bond Rate.

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, along with changes to the plans and other items, are deferred and amortized into income over either the period of expected future service of active participants, or over the lives of the plan participants. We record these deferred amounts as accumulated other comprehensive income for our non-regulated operations and as either a regulatory asset or liability for our regulated operations. As of December 31, 2007 we had deferred losses of approximately $237 million, net of income taxes in accumulated other comprehensive income. 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, 2007 (in millions):

	Pension Benefits		Other Postretirement Benefits	
	Net Benefit Expense (Income)	Change in Net Asset and Pretax Accumulated Other Comprehensive Income	Net Benefit Expense (Income)	Change in Net Asset and Pretax Accumulated Other Comprehensive Income
One percent increase in:				
Discount rates	$(11)	$ 170	$	$ 36
Expected return on plan assets	(23)		(3)	
Rate of compensation increase	2	(4)		
Health care cost trends			1	(13)
One percent decrease in:				
Discount rates	$ 13	$ (201)	$	$ (40)
Expected return on plan assets(1)	23		3	
Rate of compensation increase	(2)	3		
Health care cost trends			(1)	12

(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.

The estimates for our net benefit expense or 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 over three years, after which they are considered for inclusion in net benefit expense or income. 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 $6 million lower for the year ended December 31, 2007.

As stated in Financial Statements and Supplementary Data, Note 12, 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 initial 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. The following table shows the impact of a one percent change in the primary assumptions used in our calculation of this liability for the year ended December 31, 2007 (in millions):

	Change in Accrued Liability
One percent increase in:	
Discount rates	$ (35)
Health care cost trends	38
One percent decrease in:	
Discount rates	$ 39
Health care cost trends	(33)

Price Risk Management Activities. We record the derivative instruments used in our price risk management activities at their fair values. 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 at December 31, 2007:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Derivatives designated as hedges	$ (23)	$ (117)	$ (94)	$ 76	$ 99
Other commodity-based derivatives	(869)	(910)	(41)	(828)	41
Total	$ (892)	$ (1,027)	$ (135)	$ (752)	$ 140

Another significant assumption are the discount rates we use in determining the fair value of our derivative instruments. The table below presents the hypothetical sensitivity of our commodity- based price risk management activities to changes in fair values arising from changes in the discount rates we used to determine the fair value of our derivatives at December 31, 2007:

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Derivatives designated as hedges	$ (23)	$ (21)	$ 2	$ (25)	$ (2)
Other commodity-based derivatives	(869)	(846)	23	(894)	(25)
Total	$ (892)	$ (867)	$ 25	$ (919)	$ (27)

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to anticipated market liquidity and the credit risk of our counterparties. We believe the application of these assumptions derive a fair value that is representative of the proceeds we would receive if we disposed of our derivative instruments. We currently do not consider the impact of our credit risk in determining the fair value of our derivative liabilities, which we will begin considering upon our adoption of SFAS No. 157, *Fair Value Measurements*, on January 1, 2008. The assumptions and methodologies we use to determine the fair values of our derivatives may differ from those used by our derivative counterparties, and these differences can be significant. As a result, the actual settlement of our price risk management activities could differ materially from the fair value recorded and could impact our future operating results.

Deferred Taxes and Uncertain Income Tax Positions. We record deferred income tax assets and liabilities reflecting tax consequences deferred to future periods based on differences between the financial statement carrying value of assets and liabilities and the tax basis of assets and liabilities. Additionally, our deferred tax assets and liabilities also reflect our assessment that tax positions taken, and the resulting tax basis, are more likely than not to be sustained if they are audited by taxing authorities. Our most significant judgments on tax related matters include, but are not limited to, the items noted below. All of these matters involve the exercise of significant judgment which could change and materially impact our financial condition or results of operations. For a further discussion of these items and other income tax matters, see Item 8, Financial Statements and Supplementary Data, Note 4.

Valuation Allowance. The realization of our deferred tax assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences are deductible. Valuation allowances are established when necessary to reduce deferred income tax assets to the amounts we believe are more likely than not to be recovered. In evaluating our valuation allowance, we consider the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowance could materially impact our results of operations.

Uncertain Tax Positions. We have liabilities for unrecognized tax benefits related to uncertain tax positions connected with ongoing examinations and open tax years. Changes in our assessment of these liabilities may require us to increase the liability and record additional tax expense or reverse the liability and recognize a tax benefit which would positively or negatively impact our effective tax rate.

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Undistributed Earnings of Foreign Investees and Certain Unconsolidated Affiliates. We record deferred tax liabilities on the undistributed earnings of our foreign investments if we anticipate these earnings to be repatriated. If we do not plan to repatriate these foreign undistributed earnings, no provision has been made for any U.S. taxes or foreign withholding taxes. Additionally, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income. Any changes to our repatriation assumptions, including the repatriation of proceeds from sales of these investments, could require us to record additional deferred taxes.

Additionally, we believe certain of our unconsolidated affiliates undistributed earnings will ultimately be distributed to us through dividends which would be eligible for a dividends received deduction. We and our joint venture partners have the intent and ability to recover these cumulative undistributed earnings over time through dividends; however, should we subsequently determine that our unconsolidated affiliates would be unable to pay such dividends, we would be required to record additional deferred income tax liabilities.

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 that indicates that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then estimate the fair value of the asset, which considers a number of factors, including the potential value we would receive if we sold the asset and the projected cash flows of the asset based on current and anticipated future market conditions. The assessment of project level cash flows requires judgment 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. Utilizing these cash flow projections, we assess our ability to recover the carrying value of our assets and investments 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, we record an impairment charge for the excess of carrying value of the asset over its fair value. We recorded impairments of our long-lived assets of $20 million, $16 million and $73 million and impairments and losses on our investments in and advances to unconsolidated affiliates of $75 million, $13 million and $347 million during the years ended December 31, 2007, 2006 and 2005. We also recorded asset and investment impairments of our discontinued operations of $13 million and $502 million, net of minority interest during the years ended December 31, 2006 and 2005. Future changes in the economic and business environment can impact our assessments of potential impairments.

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.*

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 sale of natural gas and oil in our Exploration and Production segment, affecting gas not used in the operations of our Pipelines segment and affecting the fair value of our natural gas and oil derivative contracts held in our Marketing segment;
- Natural gas locational price differences change, affecting our ability to optimize pipeline transportation capacity contracts held in our Marketing segment; and
- Electricity price changes and locational pricing changes, affecting the value of our remaining power contracts held in our Marketing segment.

Interest Rate Risk

- Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed-rate debt;
- 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/or the related interest costs associated with that debt; and
- Weakening or strengthening of the U.S. dollar relative to the Brazilian real and the Mexican peso can affect the revenues and expenses generated by our foreign pipeline, exploration and production, and power operations.

We manage our risks by entering into contractual commitments involving physical or financial settlement that attempt to limit exposure related to future market movements. The timing and extent of our risk management activities is based on a number of factors, including our market outlook, risk tolerance and liquidity. 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 or rates 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 qualify as 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 7.

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Commodity Price Risk

Production-Related Derivatives

We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These derivative contracts are entered into by both our Exploration and Production and Marketing segments. 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. We have designated certain of these derivatives as accounting hedges. Contracts that are designated as accounting hedges will impact our earnings when the related hedged production sales occur, and, as a result, any gain or loss on these hedging derivatives would be offset by a gain or loss on the sale of the underlying hedged commodity, which is not included in the table. Contracts that are not designated as accounting hedges impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risks of our forecasted sales of 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
Impact of changes in commodity prices on production-related derivative instruments					
December 31, 2007	$ (64)	$(181)	$(117)	$ 58	$122
December 31, 2006	$124	$ (9)	$(133)	$264	$140

Other Commodity-Based Derivatives

In our Marketing segment, we have other derivative contracts that are not used to mitigate the commodity price risk associated with our natural gas and oil production. Many of these contracts, which include forwards, swaps, options and futures, are long-term historical contracts that we either intend to assign to third parties or manage until their expiration. We measure risks from these 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 of 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. To measure Value-at-Risk, we use what is known as the historical simulation technique. 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 underlying risks. These analyses and our Value-at-Risk simulations do not include commodity exposures related to our production-related derivatives (described above), our Marketing segment s natural gas transportation related contracts that are accounted for under the accrual basis of accounting, or 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 other commodity-based derivatives as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $1 million and $6 million as of December 31, 2007 and 2006. Our highest, lowest and average of the month-end values for Value-at-Risk during 2007 was $6 million, $1 million and $2 million. We may experience changes in our Value-at-Risk in the future if commodity prices are volatile.

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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 date 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. We estimate that the fair value of our long-term debt with variable rates approximates its carrying value because of the market based nature of its interest rate.

	December 31, 2007								December 31, 2006	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2008	2009	2010	2011	2012	Thereafter	Total	Value	Amounts	Value
	(In millions)									
Long-term debt and other obligations, including current portion fixed rate.	$318	$1,097	$236	$621	$ 425	$8,248	$10,945	$11,244	$14,093	$14,891
Average interest rate	6.2%	6.7%	6.1%	6.4%	7.3%	7.2%				
Long-term debt and other obligations, including current portion variable rate	$ 13	$ 14	$ 15	$ 16	$1,648	$ 163	$ 1,869	$ 1,869	$ 596	$ 596
Average interest rate	6.3%	6.3%	6.3%	6.3%	5.0%	6.3%				

Foreign Currency Exchange Rate Risk

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2007 and 2006, we have Euro-denominated debt with a principal amount of 380 million and 500 million which matures in 2009. As of December 31, 2007 and 2006, we have swaps that effectively convert 330 million and 350 million of debt into $379 million and $402 million. The remaining principal at December 31, 2007 and 2006 of 50 million and 150 million is subject to foreign currency exchange risk. A $0.10 change in the Euro to U.S. dollar exchange rate would result in a $5 million gain or loss on our unhedged Euro-denominated debt as of December 31, 2007.

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.

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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 SEC rules adopted under 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, 2007. 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, 2007. The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited the accompanying consolidated balance sheets of El Paso Corporation as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, stockholders equity, and cash flows for the years then ended. Our audits also included the financial statement schedule listed in the Index at Item 15(a) for the years ended December 31, 2007 and 2006. These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. The financial statements of Citrus Corp. and Subsidiaries (a corporation in which the Company had a 50% interest as of December 31, 2007 and 2006) and Four Star Oil & Gas Company (a corporation in which the Company had approximately a 49% and 43% interest, as of December 31, 2007 and 2006, respectively) have been audited by other auditors whose reports have been furnished to us, and our opinion on the consolidated financial statements, insofar as it relates to the amounts included from Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company, is based solely on the reports of the other auditors. In the consolidated financial statements, the Company s combined investments in these companies represent approximately 3% of total assets as of December 31, 2007 and 2006, and earnings from these investments represent approximately 23% and 24% of income before income taxes from continuing operations for the years then ended, based on the amounts audited by other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of El Paso Corporation at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2007, the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109,* effective December 31, 2006 the Company adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans - An Amendment of FASB Statements No. 87, 88, 106, and 132(R),* and effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(revised 2004), *Share-Based Payment* and the Federal Energy Regulatory Commission s accounting release related to pipeline assessment costs.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), El Paso Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited El Paso Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). El Paso Corporation 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 included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, El Paso Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2007 consolidated financial statements of El Paso Corporation and our report dated February 25, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2008

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated statements of income, comprehensive income, stockholders equity and cash flows for the year ended December 31, 2005 present fairly, in all material respects, the results of operations and cash flows of El Paso Corporation and its subsidiaries (the Company) for the year then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2005 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 audit. We conducted our audit 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 audit provides 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.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
March 2, 2006, except for the eleventh paragraph
of Note 2, as to which the date is May 10, 2006
and the tenth paragraph of Note 2, as to which
the date is February 26, 2007

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Report of Independent Registered Public Accounting Firm

To the Stockholders of Four Star Oil & Gas Company:

In our opinion, the consolidated balance sheets and the related consolidated statements of income, of stockholders equity and of cash flows (not presented separately herein) present fairly, in all material respects, the financial position of Four Star Oil & Gas Company (the Company) and its subsidiary at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Notes 3 and 4 to the financial statements, the Company has significant transactions with affiliated companies. Because of these relationships, it is possible that the terms of these transactions are not the same as those that would result from transactions among wholly unrelated parties.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2008

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Citrus Corp.:

In our opinion, the consolidated balance sheets and the related consolidated statements of income, of stockholders equity, of comprehensive income and of cash flows (not presented separately herein) present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the Company) at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with the accounting principles generally accepted in the United States of America. These consolidated financial statements are the responsibility of the Company 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 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 Notes 2 and 6 to the consolidated financial statements, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158 Employers Accounting for Defined Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R), as of December 31, 2006.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 25, 2008

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Operating revenues			
Pipelines	$ 2,494	$ 2,402	$ 2,171
Exploration and Production	2,300	1,854	1,787
Marketing	(219)	(58)	(796)
Power		6	82
Field Services			123
Corporate and eliminations	73	77	(8)
	4,648	4,281	3,359
Operating expenses			
Cost of products and services	245	238	245
Operation and maintenance	1,333	1,337	1,935
Depreciation, depletion and amortization	1,176	1,047	1,006
Taxes, other than income taxes	249	232	234
	3,003	2,854	3,420
Operating income (loss)	1,645	1,427	(61)
Earnings from unconsolidated affiliates	101	145	281
Loss on debt extinguishment	(291)	(26)	(29)
Other income	214	245	285
Other expenses	(11)	(40)	(17)
Minority interest	(6)	(1)	(1)
Interest and debt expense	(994)	(1,228)	(1,295)
Income (loss) before income taxes from continuing operations	658	522	(837)
Income taxes	222	(9)	(331)
Income (loss) from continuing operations	436	531	(506)
Discontinued operations, net of income taxes	674	(56)	(96)
Cumulative effect of accounting changes, net of income taxes			(4)
Net income (loss)	1,110	475	(606)
Preferred stock dividends	37	37	27
Net income (loss) available to common stockholders	$ 1,073	$ 438	$ (633)
Basic earnings (loss) per common share			
Income (loss) from continuing operations	$ 0.57	$ 0.73	$ (0.82)
Discontinued operations, net of income taxes	0.97	(0.08)	(0.15)
Cumulative effect of accounting changes, net of income taxes			(0.01)

Net income (loss) per common share	$ 1.54	$ 0.65	$ (0.98)
Diluted earnings (loss) per common share			
Income (loss) from continuing operations	$ 0.57	$ 0.72	$ (0.82)
Discontinued operations, net of income taxes	0.96	(0.08)	(0.15)
Cumulative effect of accounting changes, net of income taxes			(0.01)
Net income (loss) per common share	$ 1.53	$ 0.64	$ (0.98)

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	$ 285	$ 537
Accounts and notes receivable		
Customer, net of allowance of $17 in 2007 and $28 in 2006	468	516
Affiliates	196	192
Other	201	495
Inventory	131	115
Assets from price risk management activities	113	436
Assets held for sale and of discontinued operations		4,161
Deferred income taxes	191	478
Other	127	237
Total current assets	1,712	7,167
Property, plant and equipment, at cost		
Pipelines	16,750	15,672
Natural gas and oil properties, at full cost	19,048	16,572
Other	530	566
	36,328	32,810
Less accumulated depreciation, depletion and amortization	16,974	16,132
Total property, plant and equipment, net	19,354	16,678
Other assets		
Investments in unconsolidated affiliates	1,614	1,707
Assets from price risk management activities	302	414
Other	1,597	1,295
	3,513	3,416
Total assets	$ 24,579	$ 27,261

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 460	$ 478
Affiliates	5	3
Other	502	569
Short-term financing obligations, including current maturities	331	1,360
Liabilities from price risk management activities	267	278
Liabilities of discontinued operations		1,817
Margin deposits held by us	20	344
Accrued interest	195	269
Other	633	1,033
Total current liabilities	2,413	6,151
Long-term financing obligations, less current maturities	12,483	13,329
Other		
Liabilities from price risk management activities	931	924
Deferred income taxes	1,157	950
Other	1,750	1,690
	3,838	3,564
Commitments and contingencies (Note 12)		
Minority interests	565	31
Stockholders equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares of 4.99% convertible perpetual stock; stated at liquidation value	750	750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 709,192,605 shares in 2007 and 705,833,206 shares in 2006	2,128	2,118
Additional paid-in capital	4,699	4,804
Accumulated deficit	(1,834)	(2,940)
Accumulated other comprehensive loss	(272)	(343)
Treasury stock (at cost); 8,656,095 shares in 2007 and 8,715,288 shares in 2006	(191)	(203)
Total stockholders equity	5,280	4,186
Total liabilities and stockholders equity	$ 24,579	$ 27,261

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2007	**2006**	**2005**
Cash flows from operating activities			
Net income (loss)	$ 1,110	$ 475	$ (606)
Less income (loss) from discontinued operations, net of income taxes	674	(56)	(96)
Net income (loss) before discontinued operations	436	531	(510)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	1,176	1,047	1,006
Deferred income tax expense (benefit)	182	(20)	(303)
Earnings from unconsolidated affiliates, adjusted for cash distributions	88	(6)	(78)
Loss on debt extinguishment	291	26	29
Other non-cash income items	(25)	72	401
Asset and liability changes			
Accounts and notes receivable	213	344	122
Change in price risk management activities, net	(69)	(420)	325
Accounts payable	(67)	(382)	(118)
Change in margin and other deposits	90	911	(679)
Western Energy Settlement liability			(395)
Other asset changes	(150)	(179)	177
Other liability changes	(327)	(100)	(10)
Cash provided by (used in) continuing activities	1,838	1,824	(33)
Cash provided by (used in) discontinued activities	(33)	279	301
Net cash provided by operating activities	1,805	2,103	268
Cash flows from investing activities			
Capital expenditures	(2,495)	(2,164)	(1,474)
Cash paid for acquisitions, net of cash acquired	(1,197)		(1,140)
Net proceeds from the sale of assets and investments	106	673	1,424
Net change in restricted cash	33	129	(57)
Other	3	23	204
Cash used in continuing activities	(3,550)	(1,339)	(1,043)
Cash provided by discontinued activities	3,660	185	542
Net cash provided by (used in) investing activities	110	(1,154)	(501)
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	6,624	375	1,620
Payments to retire long-term debt and other financing obligations	(8,902)	(3,024)	(1,491)
Net proceeds from issuance of minority interest in consolidated subsidiary	538		

Net proceeds from the issuance of common stock		500	
Dividends paid	(149)	(145)	(121)
Net proceeds from issuance of preferred stock			723
Payments to minority interest holders		(5)	(306)
Contributions from discontinued operations	3,344	232	666
Other	5	(13)	
Cash provided by (used in) continuing activities	1,460	(2,080)	1,091
Cash used in discontinued activities	(3,627)	(464)	(843)
Net cash provided by (used in) financing activities	(2,167)	(2,544)	248
Change in cash and cash equivalents	(252)	(1,595)	15
Cash and cash equivalents			
Beginning of period	537	2,132	2,117
End of period	$ 285	$ 537	$ 2,132
Supplemental cash flow information related to continuing operations			
Interest paid, net of amounts capitalized	$ 1,054	$ 1,217	$ 1,238
Income tax payments	34	77	11

See accompanying notes

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In millions, except per share amounts)

	Year Ended December 31,					
	2007		2006		2005	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred stock, $0.01 par value:						
Balance at beginning of year	1	$ 750	1	$ 750		$
Equity offering					1	750
Balance at end of year	1	750	1	750	1	750
Common stock, $3.00 par value:						
Balance at beginning of year	706	2,118	667	2,001	651	1,953
Exchange of equity security units					14	41
Equity offering			36	107		
Other, net	3	10	3	10	2	7
Balance at end of year	709	2,128	706	2,118	667	2,001
Additional paid-in capital:						
Balance at beginning of year		4,804		4,592		4,538
Equity offering				393		
Dividends		(149)		(147)		(131)
Exchange of equity security units						230
Other, including stock-based compensation		44		(34)		(45)
Balance at end of year		4,699		4,804		4,592
Accumulated deficit:						
Balance at beginning of year		(2,940)		(3,415)		(2,809)
Net income (loss)		1,110		475		(606)
Cumulative effect of adopting of FIN No. 48		(4)				
Balance at end of year		(1,834)		(2,940)		(3,415)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(343)		(332)		1
		80		380		(333)

Other comprehensive income (loss)						
Cumulative effect of adopting SFAS No. 158, net of income tax of $4 in 2007 and $210 in 2006		(9)		(391)		
Balance at end of year		(272)		(343)		(332)
Treasury stock, at cost:						
Balance at beginning of year	(9)	(203)	(8)	(190)	(8)	(225)
Stock-based and other compensation		12	(1)	(13)		35
Balance at end of year	(9)	(191)	(9)	(203)	(8)	(190)
Unamortized compensation:						
Balance at beginning of year				(17)		(20)
Stock-based compensation						3
Adoption of SFAS No. 123(R)				17		
Balance at end of year						(17)
Total stockholders equity	700	$ 5,280	697	$ 4,186	659	$ 3,389

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2007	**2006**	**2005**
Net income (loss)	$ 1,110	$ 475	$ (606)
Foreign currency translation adjustments (net of income tax benefits of less than $1 in 2006 and $13 in 2005)		4	(9)
Pension and postretirement obligations			
Unrealized actuarial gains (losses) arising during period (net of taxes of $91 in 2007, $3 in 2006 and $2 in 2005)	181	5	(3)
Reclassification adjustments (net of taxes of $13 in 2007)	26		
Cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $2 in 2007, $196 in 2006 and $229 in 2005)	(3)	352	(415)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $65 in 2007, $15 in 2006 and $46 in 2005)	(112)	22	79
Investments available for sale:			
Unrealized gains arising during period (net of income tax of $2 in 2007, $16 in 2006 and $9 in 2005)	3	28	15
Realized gains reclassified from accumulated other comprehensive income during period (net of income tax of $8 in 2007 and $17 in 2006)	(15)	(31)	
Other comprehensive income (loss)	80	380	(333)
Comprehensive income (loss)	$ 1,190	$ 855	$ (939)

See accompanying notes.

EL PASO CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles (GAAP) and include the accounts of all majority owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. These reclassifications did not impact our reported net income (loss) or stockholders equity.

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 (see Note 17) in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity s losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the 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.

Use of Estimates

The preparation of our financial statements 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 under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Our pipelines follow the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Under SFAS No. 71, we record regulatory assets and liabilities that would not be recorded under GAAP for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Items to which we apply regulatory accounting requirements include certain 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.

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 the restrictions on this cash to be removed. As of December 31, 2007, we had $7 million of restricted cash in current assets and $91 million in other non-current assets. As of December 31, 2006, we had $8 million of restricted cash in other current assets and $123 million in other non-current assets.

Allowance for Doubtful Accounts

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

Inventory

Our inventory consists primarily of supplies and materials and is classified as current on our balance sheet. We use the average cost method to account for our inventories. We value all inventory at the lower of its cost or market value.

Property, Plant and Equipment

Pipelines and Other (Excluding Natural Gas and Oil Properties). 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, an equity return component in our regulated businesses. We capitalize major units of property replacements or improvements and expense minor items. Prior to January 1, 2006, we capitalized certain costs our interstate pipelines incurred related to their pipeline integrity programs as part of our property, plant and equipment. Beginning January 1, 2006, we began expensing these costs based on FERC guidance. During the years ended December 31, 2007 and 2006, we expensed approximately $18 million and $19 million as a result of the adoption of this accounting release, which was approximately $0.03 per basic and fully diluted share in 2007 and $0.02 per basic and fully diluted share in 2006.

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.

When we retire property, plant and equipment in our regulated operations, we charge accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell or dispose of the assets, less their 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.

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 on a country-by-country basis. 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 for impairment through a ceiling test calculation 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 quarterly. We transfer unproved property costs into the amortizable base when properties are determined to have proved reserves. In addition, in areas where a natural gas or oil reserve base exists, 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; 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 discounted at 10 percent plus the lower of cost or fair market value of unproved properties, net of related income tax effects. We utilize end-of-period spot prices when calculating future net revenues unless those prices result in a ceiling test charge in which case we evaluate price recoveries subsequent to the end of the period. If total capitalized costs exceed the ceiling, we are required to write-down our capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write-down is 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.

Asset and Investment Divestitures/Impairments

We evaluate 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) the long-lived asset s ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. 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 the asset downward, if necessary, to their estimated fair value. 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 impairment is impacted by a number of factors, including the nature of the assets being sold and our established time frame for completing the sale, among other factors.

We reclassify the asset or assets to be sold as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have significant long-term continuing involvement with those assets after they are sold. We cease depreciating assets in the period that they are reclassified as either held for sale or discontinued operations.

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense 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 13.

Our pension and other postretirement benefit plans use the recognition provisions of SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an Amendment of FASB Statements No. 87, 88, 106 and 132(R).* Under SFAS No. 158, we record an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. Any deferred amounts related to unrealized gains and losses or changes in actuarial assumptions are recorded either as a regulatory asset or liability for our regulated operations or in accumulated other comprehensive income (loss), a component of stockholders equity, for our nonregulated operations until those gains and losses are recognized in the income statement. For a further discussion of our application of SFAS No. 158, see Note 13.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. We record revenues for these products and services which include estimates of amounts earned but unbilled. We estimate these unbilled revenues related to services provided or products delivered based on contract data, regulatory information, commodity prices, and preliminary throughput and allocation measurements, among other items. 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. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. 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. 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 delivery and 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 products and services.

Marketing revenues. Our Marketing segment derives revenues from physical natural gas and power transactions and the management of derivative contracts. Our derivative transactions are recorded at their fair value and changes in their fair value are reflected net in operating revenues. For a further discussion of our income recognition policies on derivatives see *Price Risk Management Activities* below. The impact of non-derivative transactions, including our transportation contracts, are recognized net in operating revenues based on the contractual or market price and related volumes at the time the commodity is delivered or the contracts are terminated.

Environmental Costs and Other Contingencies

Environmental Costs. We record liabilities at their undiscounted amounts on our balance sheet as other current and long-term liabilities when 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 recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

We evaluate any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the creditworthiness or solvency of the third party, among other factors. When recovery is assured, 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 a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

Price Risk Management Activities

Our price risk management activities consist of the following activities:

- derivatives entered into to hedge or otherwise reduce the commodity exposure on our natural gas and oil production and interest rate and foreign currency exposure on our long-term debt; and

- derivatives not intended to hedge these exposures, including those related to our legacy trading activities that we 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 7 for a further discussion of our price risk management activities. During 2007, we adopted the provisions of FASB Staff Position (FSP) FIN No. 39-1, *Offsetting of Amounts Related to Certain Contracts*, which allowed companies the option to offset amounts recorded for their derivative contracts with cash collateral posted or held if the contracts are executed with the same counterparty and under the same master netting arrangement. We elected to continue to report separately amounts recorded for derivative contracts from cash collateral posted or held on our balance sheet and, as a result, our adoption of this standard had no impact on our financial statements.

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 that we have not designated as hedges are marked-to-market each period and changes in their fair value are reflected as revenues.

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 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.

Effective January 1, 2007, we adopted the provisions of FIN No. 48, *Accounting for Uncertainty in Income Taxes.* FIN No. 48 clarifies SFAS No. 109, *Accounting for Income Taxes,* and requires us to evaluate our tax positions for all jurisdictions and for all years where the statute of limitations has not expired. FIN No. 48 requires companies to meet a more-likely-than-not threshold (i.e. greater than a 50 percent likelihood of a tax position being sustained under examination) prior to recording a benefit for their tax positions. Additionally, for tax positions meeting this more-likely-than-not threshold, the amount of benefit is limited to the largest benefit that has a greater than 50 percent probability of being realized upon effective settlement. We recognize interest and penalties related to unrecognized tax benefits in income tax expenses on our income statement. For a further discussion of the impact of the adoption of FIN No. 48, see Note 4.

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 effects of translating the local currency to the U.S. dollar are included as a separate component of accumulated other comprehensive income (loss) in stockholders equity on our balance sheet.

Accounting for Asset Retirement Obligations

We account for our asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* and Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations*. We record a liability for legal obligations associated with the replacement, removal, or retirement of our long-lived assets. 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 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 as depreciation, depletion and amortization expense in our income statement. Our regulated pipelines have the ability to recover 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.

Accounting for Stock-Based Compensation.

On January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment,* prospectively for awards of stock-based compensation granted after that date and for the unvested portion of outstanding awards at that date. We measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in our financial statements over the requisite service period. Prior to January 1, 2006, we accounted for stock-based compensation awards using the intrinsic value method under the provisions of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations, and did not record compensation expense on stock options that were granted at the market value of the stock on the date of grant. For additional information on our stock-based compensation awards, see Note 15.

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The following table shows the impact on the net loss available to common stockholders and loss per share had we applied the provisions of SFAS No. 123 in 2005 (in millions, except for per share amounts):

Net loss available to common stockholders, as reported	$ (633)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	12
Deduct: Total stock-based compensation expense determined under fair-value based method for all awards, net of taxes	(19)
Net loss available to common stockholders, pro forma	$ (640)
Loss per common share:	
Basic and diluted, as reported	$ (0.98)
Basic and diluted, pro forma	$ (0.99)

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2007, the following accounting standards and interpretations had not yet been adopted by us.

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance on measuring the fair value of assets and liabilities in the financial statements. We will adopt the provisions of this standard for our financial assets and liabilities effective January 1, 2008, at which time we will be required to consider our own credit standing in the determination of the fair value of our liabilities. Adoption of the standard is not expected to have a material impact on our financial statements. The FASB provided a one year deferral of the adoption of SFAS No. 157 for certain non-financial assets and liabilities. We have elected to defer the adoption for certain of our non-financial assets and liabilities and are currently evaluating the impact, if any, that the deferred provisions of this standard will have on our financial statements.

Measurement Date of Pension and Other Postretirement Benefits. In December 2006, we adopted the recognition provisions of SFAS No. 158. Beginning in 2008, this standard will also require us to change the measurement date of our pension and other postretirement benefit plans from September 30, the date we currently use, to December 31. Adoption of the measurement date provisions of this standard is not expected to have a material impact on our financial statements.

Fair Value Option. In February 2007, the FASB issued SFAS No. 159, *Fair Value Option for Financial Assets and Financial Liabilities* including an Amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, which permits entities to choose to measure many financial instruments and certain other items at fair value. We will adopt the provisions of this standard effective January 1, 2008, and do not anticipate that it will have a material impact on our financial statements.

Business Combinations. In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*, which provides revised guidance on the accounting for acquisitions of businesses. This standard changes the current guidance to require that all acquired assets, liabilities, minority interest and certain contingencies be measured at fair value, and certain other acquisition-related costs be expensed rather than capitalized. SFAS No. 141(R) will apply to acquisitions that are effective after December 31, 2008, and application of the standard to acquisitions prior to that date is not permitted.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which provides guidance on the presentation of minority interest in the financial statements. This standard requires that minority interest be presented as a separate component of equity rather than as a mezzanine item between liabilities and equity, and also requires that minority interest be presented as a separate caption in the income statement. This standard also requires all transactions with minority interest holders, including the issuance and repurchase of minority interests, be accounted for as equity transactions unless a change in control of the subsidiary occurs. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and we are currently evaluating the impact that this standard will have on our financial statements.

2. Acquisitions and Divestitures

Acquisitions

Peoples Energy Production Company (Peoples). In September 2007, we acquired Peoples for $887 million using cash on hand and borrowings under our revolving credit facilities. Peoples is an exploration and production company with natural gas and oil properties located primarily in the Arklatex, Texas Gulf Coast and Mississippi areas and in the San Juan and Arkoma Basins. We accounted for this acquisition under the purchase method of accounting and allocated the purchase price primarily to natural gas and oil properties on our balance sheet, which is subject to change based on the finalization of this allocation. We did not record any goodwill associated with this transaction.

South Texas properties. In January 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas, for approximately $254 million.

Medicine Bow. In August 2005, we completed the acquisition of Medicine Bow, a privately held energy company, for total cash consideration of approximately $853 million. As part of the transaction, we also acquired Four Star, an unconsolidated affiliate of Medicine Bow, and we reflect our proportionate share of their operating results as earnings from unconsolidated affiliates in our financial statements (see Note 17). In 2007, we increased our ownership in Four Star from 43 percent to 49 percent.

Gulf LNG. In February 2008, we closed on the previously announced acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, a liquefied natural gas (LNG) terminal which is currently under construction in Pascagoula, Mississippi, and paid $294 million.

Divestitures

During 2007, 2006 and 2005, we sold a number of assets and investments in each of our business segments and corporate activities. The table and discussions below summarize the assets sold and proceeds from these sales:

	2007	2006	2005
		(In millions)	
Power	$ 1	$ 531	$ 625
Field Services			657
Exploration and Production	2	122	7
Marketing	24		
Pipelines	36	3	49
Corporate	3	2	121
Total continuing[1]	66	658	1,459
Discontinued	3,660	368	577
Total	$ 3,726	$ 1,026	$ 2,036

(1) Proceeds exclude any returns of capital on our investments in unconsolidated affiliates and cash transferred with the assets sold and include costs incurred in preparing assets

for disposal. These items increased our sales proceeds by $40 million for the year ended December 31, 2007, increased our sales proceeds by $15 million for the year ended December 31, 2006, and decreased our sales proceeds by $35 million for the years ended December 31, 2005.

Power. Assets sold in 2006 consisted primarily of our interests in MCV and power plants in Brazil, Asia, and Central America. Assets sold in 2005 consisted primarily of interests in our power contract restructuring entities and power plants in India and Korea.

Field Services. Assets sold in 2005 consisted primarily of our investment in Enterprise and the Javelina natural gas processing and pipeline assets.

Exploration and Production, Marketing, Pipelines and Corporate. Assets sold consisted primarily of our investment in NYMEX and our Stagecoach Pipeline lateral in 2007, natural gas and oil properties in south Texas in 2006 and pipeline facilities and gathering systems located in the southeastern and western U.S. and Lakeside Technology Center in 2005.

Discontinued Operations and Assets Held for Sale

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals to be disposed of by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these operations do not maintain separate cash balances, we reflect the net cash flows generated from these businesses as a contribution to our continuing operations in cash from continuing financing activities. The following is a description of our discontinued operations and summarized results of these operations for the periods ended December 31, 2007, 2006 and 2005. We also had $28 million of assets held for sale as of December 31, 2006. As of December 31, 2007, all of our assets and liabilities related to our discontinued operations and assets held for sale had been sold.

ANR and Related Operations. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for approximately $3.7 billion. We recorded a gain on the sale of $648 million, net of taxes of $354 million. Included in the net assets of these discontinued operations as of the date of sale were net deferred tax liabilities assumed by the purchaser. We also recorded approximately $188 million of deferred taxes in 2006 in conjunction with the sale.

International Power Operations. During 2006, we completed the sale of all of our discontinued international power operations including Macae, a wholly owned power plant facility in Brazil, and Asian and Central American power assets for total net proceeds of approximately $368 million. Previously in 2005, we recognized approximately $499 million of impairments, net of minority interest, based upon indications of the value we would receive upon the sale of the assets.

South Louisiana Gathering and Processing Operations. During 2005, we completed the sale of our south Louisiana gathering and processing assets for net proceeds of approximately $486 million and recorded a pre-tax gain of approximately $394 million. These assets were part of our historical Field Services segment.

Other. Prior to 2005, our Canadian and certain other international natural gas and oil production operations and our petroleum markets businesses and operations were approved for sale. We completed the sale of substantially all of these properties in 2004 and 2005.

Income Taxes on Discontinued Operations. For the years ended December 31, 2007, 2006 and 2005, we incurred income tax expense associated with our discontinued operations of $369 million, $274 million and $179 million resulting in an effective tax rate of approximately 35%, 126% and 216% for these years. The effective tax rates in 2006 and 2005 are significantly higher than the statutory rate of 35% primarily due to the following items:

- In 2006, we recorded approximately $188 million of deferred taxes upon agreeing to sell the stock of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission. Prior to our decision to sell, we only recorded deferred taxes on individual assets/liabilities and a portion of our investment in the stock of one of these companies;
- In 2005, (i) impairments and operating losses of certain foreign investments for which no tax benefit was available, (ii) receipt of dividends from foreign subsidiaries taxable in the U.S. and (iii) state income taxes.

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The summarized operating results and financial position data of our discontinued operations were as follows:

	ANR and Related Operations	International Power Operations	South Louisiana Gathering and Processing Operations	Other	Total
			(In millions)		
Year Ended December 31, 2007					
Revenues	$ 101	$	$	$	$ 101
Costs and expenses	(43)				(43)
Other expense[(1)]	(7)				(7)
Interest and debt expense	(10)				(10)
Income taxes	(15)				(15)
Income from operations					26
Gain on sale, net of income taxes of $354 million					648
Income from discontinued operations, net of income taxes					$ 674
Year Ended December 31, 2006					
Revenues	$ 581	$ 149	$	$	$ 730
Costs and expenses	(334)	(159)			(493)
Gain (loss) on long-lived assets		(11)	5		(6)
Other income	63	3			66
Interest and debt expense	(65)	(14)			(79)
Income taxes					(274)
Loss from discontinued operations, net of income taxes					$ (56)
Year Ended December 31, 2005					
Revenues	$ 612	$ 207	$ 292	$ 127	$ 1,238
Costs and expenses	(372)	(216)	(264)	(182)	(1,034)
Gain (loss) on long-lived assets		(510)	394	2	(114)
Other income	62	13		12	87
Interest and debt expense	(68)	(26)			(94)
Income taxes					(179)
Loss from discontinued operations, net of income taxes					$ (96)

(1)

Includes a loss of approximately $19 million associated with the extinguishment of certain debt obligations.

	ANR and Related Operations (In millions)
December 31, 2006	
Assets of discontinued operations	
Accounts and notes receivable	$ 19
Other current assets	757
Property, plant and equipment, net	3,357
Total assets	$ 4,133
Liabilities of discontinued operations	
Accounts payable	$ 64
Other current liabilities	160
Long-term debt	741
Deferred income taxes	852
Total liabilities	$ 1,817

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3. 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:

	2007	2006 (In millions)	2005
Other Income			
Interest income	$ 49	$ 138	$ 125
Allowance for funds used during construction	32	20	23
Deferred taxes on capitalized funds used during construction	18	11	14
Development, management and administrative services fees on power projects from affiliates	3	7	11
Reversal of liability for legacy crude oil purchases (see Note 12)	77		
Foreign currency gain, net			36
Gain on sale of non-equity method investments	24	47	40
Dividend income		14	19
Other	11	8	17
Total	$ 214	$ 245	$ 285
Other Expenses			
Foreign currency losses, net	$ 1	$ 20	$
Loss on sale of non-equity method investments		12	
Other	10	8	17
Total	$ 11	$ 40	$ 17

4. 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:

	2007	2006 (In millions)	2005
Pretax Income (Loss)			
U.S.	$ 587	$ 442	$ (872)
Foreign	71	80	35
	$ 658	$ 522	$ (837)
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ (1)	$ 7	$ (13)
State	33	(15)	(37)
Foreign	8	19	22
	40	11	(28)
Deferred			
Federal	217	(46)	(372)

State	(39)	32	67
Foreign	4	(6)	2
	182	(20)	(303)
Total income taxes	$ 222	$ (9)	$ (331)

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

	2007	2006	2005
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$ 230	$ 183	$ (293)
Increase (decrease)			
Audit settlements		(159)	(58)
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(40)	(35)	(36)
Texas margins tax credit on accumulated net operating loss	(16)		
State income taxes, net of federal income tax effect	14	20	(16)
Sales and write-offs of foreign investments	1	(17)	(7)
Foreign income taxed at different rates	24	(13)	75
IRS interest refund		(11)	
Valuation allowances	10	23	34
Non-taxable Medicare reimbursements	(3)	(6)	(25)
Other	2	6	(5)
Income taxes	$ 222	$ (9)	$ (331)
Effective tax rate	34%	(2)%	40%

In 2006 and 2005, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the conclusion of IRS audits. In 2006, our audit settlements primarily relate to the conclusion of the audits of The Coastal Corporation s 1998-2000 tax years and El Paso s 2001 and 2002 tax years which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. In 2005, audit settlements primarily relate to the conclusion of The Coastal Corporation s IRS tax audits for years prior to 1998.

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

	2007	2006
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 3,106	$ 2,736
Investments in affiliates	227	555
Regulatory and other assets	107	53
Total deferred tax liability	3,440	3,344
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,135	1,560
State	188	214
Foreign	105	81
Price risk management activities	439	284
Legal and other reserves	321	332
Other	464	568

Valuation allowance	(137)	(127)
Total deferred tax asset	2,515	2,912
Net deferred tax liability	$ 925	$ 432

We expect to receive sales proceeds within the U.S. on Asia and Central America power assets and have recorded U.S. deferred tax assets and liabilities on book versus tax basis differences in these assets. As of December 31, 2007 and 2006, we have U.S. deferred tax assets of $12 million and $45 million and U.S. deferred tax liabilities of $1 million and $2 million related to these investments. Cumulative undistributed earnings from substantially all of the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding the 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, 2007, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $117 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.

Unrecognized Tax Benefits (Liabilities) for Uncertain Tax Matters (FIN No. 48). We file income tax returns in the U.S. federal jurisdiction, and various states and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1999. Additionally, the Internal Revenue Service has completed an examination of El Paso s U. S. income tax returns for 2003 and 2004, with a tentative settlement at the appellate level for all issues. While the settlement of these matters is expected to change our unrecognized tax benefits in the next twelve months, we do not anticipate the impact to be significant to our results of operations, financial condition or liquidity. For our remaining open tax years, our unrecognized tax benefits (liabilities for uncertain tax matters) could increase or decrease our income tax expense and effective income tax rates as these matters are finalized, although we are currently unable to estimate the range of potential impacts these matters could have on our financial statements.

Upon the adoption of FIN No. 48, we recorded additional liabilities for unrecognized tax benefits of $2 million, including interest and penalties, which we accounted for as an increase of $4 million to our January 1, 2007 accumulated deficit and an increase of $2 million to additional paid in capital. The following table below shows the change in unrecognized tax benefits from January 1, 2007 to December 31, 2007:

Balance at January 1, 2007[(1)]	$ 139
Additions:	
Tax positions taken in prior years	2
Tax positions taken in current year	23
Foreign currency fluctuations	1
Reductions:	
Tax positions taken in prior years	(5)
Settlements with taxing authorities	(3)
Balance at December 31, 2007[(2)]	$ 157

(1) Balance at January 1, 2007 including $39 million of interest and penalties was $178 million.

(2) There were no lapses in statutes of limitations during 2007 that impacted our unrecognized tax benefits.

As of December 31, 2007, approximately $132 million (net of federal tax benefits) of unrecognized tax benefits would affect our income tax expense and our effective income tax rate if recognized in future periods. While the amount of our unrecognized tax benefits could change in the next twelve months, we do not expect this change to have a significant impact on our results of operations or financial position.

During the year ended December 31, 2007, we recognized $6 million in interest and penalties. We had $45 million accrued for the payment of interest and penalties as of December 31, 2007.

Tax Credit and NOL Carryovers. As of December 31, 2007, we have U.S. federal alternative minimum tax credits of $344 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2007:

	Carryover Period				
	2008	**2009-2012**	**2013-2017**	**2018-2027**	**Total**
			(In millions)		
U.S. federal net operating loss	$	$ 19	$ 17	$2,335	$2,371
State net operating loss	197	752	553	1,224	2,726

We also had $240 million of foreign net operating loss carryovers and $68 million of foreign capital loss carryovers which carryover indefinitely. Usage of our U.S. federal carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

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. As part of our assessment, we consider future reversals of existing taxable temporary differences, primarily related to depreciation. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

5. Earnings Per Share

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

	2007		2006		2005	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)					
Income (loss) from continuing operations	$ 436	$ 436	$ 531	$ 531	$ (506)	$ (506)
Convertible preferred stock dividends	(37)	(37)	(37)		(27)	(27)
Income (loss) from continuing operations available to common stockholders	399	399	494	531	(533)	(533)
Discontinued operations	674	674	(56)	(56)	(96)	(96)
Cumulative effect of accounting changes, net of income taxes					(4)	(4)
Net income (loss) available to common stockholders	$ 1,073	$ 1,073	$ 438	$ 475	$ (633)	$ (633)
Weighted average common shares outstanding	696	696	678	678	646	646
Effect of dilutive securities:						
Options and restricted stock		3		4		
Convertible preferred stock				57		
Weighted average common shares outstanding and dilutive potential common shares	696	699	678	739	646	646
Earnings per common share:						
Income (loss) from continuing operations	$ 0.57	$ 0.57	$ 0.73	$ 0.72	$ (0.82)	$ (0.82)
Discontinued operations, net of income taxes	0.97	0.96	(0.08)	(0.08)	(0.15)	(0.15)
Cumulative effect of accounting changes, net of income taxes					(0.01)	(0.01)

Net income (loss)	$ 1.54	$ 1.53	$ 0.65	$ 0.64	$ (0.98)	$ (0.98)

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. These potentially dilutive securities consist of our employee stock options, restricted stock, convertible preferred stock, trust preferred securities, and zero coupon convertible debentures (which were paid off in April 2006). For the year ended December 31, 2007 and 2006, certain employee stock options and our trust preferred securities were antidilutive. Additionally, in 2006, our zero coupon convertible debentures (redeemed in April 2006) were antidilutive and in 2007 our convertible preferred stock was antidilutive. For the year ended December 31, 2005, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive. For a discussion of our capital stock activity, our stock-based compensation arrangements, and other instruments noted above, see Notes 14 and 15.

6. Fair Value of Financial Instruments

	As of December 31,			
	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$12,814	$13,113	$14,689	$15,487
Commodity-based price risk management derivatives	(892)	(892)	(395)	(395)
Interest rate and foreign currency derivatives	109	109	43	43
Investments	4	4	23	23

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As of December 31, 2007 and 2006, the 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 7 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.

7. 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, 2007 and 2006. 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 and swaps, other natural gas and power purchase and supply contracts, and derivatives from our historical energy trading activities. 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.

	As of December 31,	
	2007	2006
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (23)	$ 61
Other commodity-based derivative contracts	(869)	(456)
Total commodity-based derivatives	(892)	(395)
Interest rate and foreign currency derivatives	109	43
Net liabilities from price risk management activities[1]	$ (783)	$ (352)

(1) Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. We use commodity pricing data either obtained or derived from an independent pricing source and other assumptions about certain power and natural gas markets to develop price curves. The curves are then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discount these estimated settlement values using a LIBOR curve. 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. We believe this methodology results in a fair value that is representative of the proceeds we would receive if we disposed of our derivative instruments. The estimates utilized in determining the fair value of derivatives are subject to revisions, either up or down, in future periods based on changes in market conditions. During 2006, we changed the independent pricing source that provided the pricing data we used in valuing certain of our commodity-based derivative contracts. These changes did not have a material impact on the fair value of our positions.

Derivatives Designated as Hedges

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. When we enter into a derivative contract, we may designate the derivative as either a cash flow hedge or a fair value hedge, at which time we prepare the documentation required under SFAS No. 133. 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. 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 or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur. 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. The ineffective portion of a hedge s change in fair value, if any, is recognized immediately in earnings as a component of operating revenues or interest and debt expense in our income statement. A discussion of each of our hedging activities is as follows:

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Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use fixed price swaps and floor and ceiling option contracts to limit our exposure to decreases in commodity prices as well as fluctuations in foreign currency and interest rates with the objective of limiting the variability of the cash flows 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, 2007 and 2006 follows:

	Accumulated Other Comprehensive Income (Loss) 2007	2006	Estimated Income (Loss) Reclassification in 2008[1]	Final Termination Year
		(In millions)		
Commodity cash flow hedges				
Held by consolidated entities	$ (25)	$ 84	$ 46	2012
Held by unconsolidated affiliates	(4)	(4)	(1)	2013
Total commodity cash flow hedges	(29)	80	45	
Interest rate and foreign currency cash flow hedges				
Fixed rate	(2)	3		2015
De-designated	(4)	(3)		2009
Total foreign currency cash flow hedges	(6)			
Total interest rate and cash flow hedges	$ (35)	$ 80	$ 45	

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

For the years ended December 31, 2007, 2006 and 2005, we recognized a net loss of $3 million, a net gain of $10 million and a net loss of $5 million, net of income taxes, respectively, in our income (loss) from continuing operations related to the ineffective portion of our cash flow hedges.

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 protect the value of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments and have recorded the fair value of these derivatives as a component of long-term debt and the related accrued interest. As of December 31, 2007 and 2006, these derivatives were as follows (amounts in millions):

Derivative	Weighted	Hedged Debt 2007	2006	Price Risk Management Asset (Liability)[1] 2007	2006

	Average Rate				
Fixed-to-floating swaps	LIBOR + 4.18%	$ 218	$ 440	$ (5)	$ (31)
Fixed-to-floating cross currency swaps[(2)]	LIBOR + 4.23%	379	402	118	67
				$ 113	$ 36

(1) We did not record any ineffectiveness related to our fair value hedges in 2006 or 2007.

(2) As of December 31, 2007 and 2006, these derivatives, when combined with our Euro denominated debt, converted 330 million Euro and 350 million Euro of our debt to $379 million and $402 million.

Other Commodity-Based Derivatives.

Our other commodity-based derivatives primarily relate to derivative contracts not designated as hedges and other contracts associated with our legacy trading activities.

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

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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 the fair value of our derivative contracts, net of collateral and liabilities where a right of offset exists. It is presented by type of derivative counterparty in which we had net asset exposure as of December 31, 2007 and 2006:

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2007				
Energy marketers	$ 30	$ 110	$	$ 140
Natural gas and electric utilities			71	71
Financial institutions and other	86			86
Net financial instrument assets	116	110	71	297
Collateral held by us		(100)	(47)	(147)
Net exposure from derivative assets	$ 116	$ 10	$ 24	$ 150

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2006				
Energy marketers	$ 136	$ 81	$	$ 217
Natural gas and electric utilities	6		64	70
Commodity exchanges	321			321
Financial institutions and other	153		1	154
Net financial instrument assets	616	81	65	762
Collateral held by us	(328)	(78)	(64)	(470)
Net exposure from derivative assets	$ 288	$ 3	$ 1	$ 292

(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.

We have approximately 48 counterparties as of December 31, 2007. 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, 2007, four counterparties, (Merrill Lynch Commodities, Morgan Stanley Group, Central Lomas de Real and Constellation Energy Commodities Group, Inc.) comprise 20 percent, 16 percent, 15 percent and 12 percent, respectively of our net financial asset exposure. As of December 31, 2006, three counterparties (Deutsche Bank AG, J. Aron & Company and Constellation Energy Commodities Group, Inc.) comprised 39 percent, 18 percent and 16 percent of our net financial instrument asset exposure. The 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.

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8. Regulatory Assets and Liabilities

Our regulatory assets and liabilities relate to our interstate pipeline operations and are included in other current and non-current assets and liabilities on our balance sheets. These balances are recoverable or reimbursable over various periods. Below are the details of our regulatory assets and liabilities as of December 31:

	2007	2006
	(In millions)	
Current regulatory assets	$	$ 6
Non-current regulatory assets		
Taxes on capitalized funds used during construction	122	106
Postretirement benefits	18	22
Unamortized net loss on reacquired debt	59	19
Under-collected income taxes	8	3
Other	14	21
Total non-current regulatory assets	221	171
Total regulatory assets	$ 221	$ 177
Current regulatory liabilities	$ 41	$ 16
Non-current regulatory liabilities		
Environmental liability	143	130
Cost of removal of offshore assets	7	12
Property and plant depreciation	67	70
Postretirement benefits	90	19
Plant regulatory liability	11	11
Excess deferred income taxes	3	6
Other	7	4
Total non-current regulatory liabilities	328	252
Total regulatory liabilities	$ 369	$ 268

9. 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:

	2007	2006
	(In millions)	
Other current assets		
Prepaid expenses	$ 66	$ 72
Margin and other deposits held by others	27	60
Deposits		60
Other	34	45
Total	$ 127	$ 237

Other non-current assets		
Pension, other postretirement and postemployment benefits (Note 13)	$ 660	$ 332
Notes receivable from affiliates	220	232
Restricted cash (Note 1)	91	123
Unamortized debt expenses	107	133
Regulatory assets (Note 8)	221	171
Long-term receivables	116	131
Other	182	173
Total	$ 1,597	$ 1,295

	2007	2006
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 89	$ 95
Income taxes	47	17
Environmental, legal and rate reserves (Note 12)	174	560
Deposits	62	30
Pension and other postretirement benefits (Note 13)	28	30
Accrued lease obligations		56
Asset retirement obligations (Note 10)	41	89
Dividends payable	37	37
Regulatory liabilities (Note 8)	41	16
Other	114	103
Total	$ 633	$ 1,033
Other non-current liabilities		
Environmental and legal reserves (Note 12)	$ 590	$ 616
Pension, other postretirement and postemployment benefits (Note 13)	236	294
Regulatory liabilities (Note 8)	328	252
Asset retirement obligations (Note 10)	212	154
Other deferred credits	62	159
Insurance reserves	111	118
Other	211	97
Total	$ 1,750	$ 1,690

10. Property, Plant and Equipment

Depreciable lives. The table below presents the depreciation method and depreciable lives of our property, plant and equipment:

	Method	Depreciable Lives
	(In years)	
Regulated interstate systems	Composite	(1)
Non-regulated assets		
Natural gas and oil properties	(2)	(2)
Transmission and storage facilities	Straight-line	15-26
Gathering and processing systems	Straight-line	15-40
Transportation equipment	Straight-line	5
Buildings and improvements	Straight-line	4-49
Office and miscellaneous equipment	Straight-line	1-10

(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.

(2) 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. See Note 1 for additional information.

Excess purchase costs. As of December 31, 2007 and 2006, TGP and EPNG have excess purchase costs associated with their historical acquisition. Total excess costs on these pipelines were approximately $2.5 billion and accumulated depreciation was approximately $0.4 billion at December 31, 2007 and 2006. These excess costs are being depreciated over the life of the pipeline assets to which the costs were assigned, and our related depreciation expense for each year ended December 31, 2007, 2006, and 2005 was approximately $42 million. We do not currently earn a return on these excess purchase costs from our rate payers.

Capitalized costs during construction. We capitalize a carrying cost on funds related to our construction of long-lived assets and reflect these as increases in the cost of the asset on our balance sheet. This carrying cost consists of (i) an interest cost on our debt that could be attributed to the assets being constructed, and (ii) in our regulated transmission business, a return on our equity, that could be attributed to the assets being constructed. The debt portion is calculated based on the average cost of debt. Interest costs capitalized are included as a reduction of interest expense in our income statements and were $50 million, $41 million and $41 million during the years ended December 31, 2007, 2006 and 2005. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized are included as other non-operating income on our income statement and were $32 million, $20 million and $23 million during the years ended December 31, 2007, 2006 and 2005.

Construction work-in progress. At December 31, 2007 and 2006, we had approximately $1.6 billion and $1 billion of construction work-in-progress included in our property, plant and equipment.

Asset retirement obligations. We have legal obligations associated with the retirement of our natural gas and oil wells and related infrastructure, natural gas pipelines, transmission facilities and storage wells, and obligations related to our corporate headquarters building. In our production operations, we have obligations to plug wells when abandoned because production is exhausted or we no longer plan to use the wells. In our pipeline operations, our legal obligations primarily involve 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 ever demolished, replaced or renovated. We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record.

Where we can reasonably estimate the asset retirement obligation liability, we accrue a liability based on an estimate of the timing and amount of their settlement In estimating the fair value of the liabilities associated with our asset retirement obligations, we utilize several assumptions, including a projected inflation rate of 2.5 percent, and credit-adjusted discount rates that currently range from six to eight percent. We record changes in these estimates based on the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes result from obtaining new information in our Exploration and Production segment about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. In 2006, we also revised our estimates due primarily to the impacts of hurricanes Katrina and Rita. In our pipelines operations, we intend on operating and maintaining our natural gas pipeline and storage systems as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the asset retirement obligation liability for the substantial majority of our natural gas pipeline and storage system assets because these assets have indeterminate lives.

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:

	2007	**2006**
	(In millions)	
Net asset retirement liability at January 1	$ 243	$ 252
Liabilities settled	(62)	(48)
Accretion expense	23	19
Liabilities incurred	16	5
Changes in estimate	33	15
Net asset retirement liability at December 31	$ 253	$ 243

11. Debt, Other Financing Obligations and Other Credit Facilities

	Year Ended December 31,	
	2007	**2006**
	(In millions)	
Short-term financing obligations, including current maturities	$ 331	$ 1,360
Long-term financing obligations	12,483	13,329
Total	$ 12,814	$ 14,689

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The following provides additional detail on our long-term financing obligations:

Colorado Interstate Gas Company (CIG)		
Notes, 5.95% through 6.85%, due 2015 through 2037	$ 575	$ 700
El Paso Corporation		
Notes, 6.375% through 10.75%, due 2008 through 2037	6,090	7,939
$1.25 billion revolver, variable due 2009		200
$1.5 billion revolver, variable due 2012	425	
El Paso Natural Gas Company (EPNG)		
Notes, 5.95% through 8.625%, due 2010 through 2032	1,169	1,115
El Paso Exploration & Production Company (EPEP)		
Senior note, 7.75%, due 2013	1	1,200
Revolving credit facility, variable due 2012	750	
Revolving credit facility, variable due 2010		145
El Paso Pipeline Partners, L.P.		
Revolving credit facility, variable due 2012	455	
Southern Natural Gas Company (SNG)		
Notes, 5.9% through 8.0%, due 2008 through 2032	1,134	1,200
Tennessee Gas Pipeline Company		
Notes, 6.0% through 8.375%, due 2011 through 2037	1,626	1,626
Other	297	310
	12,522	14,435
Other financing obligations		
Capital Trust I, due 2028	325	325
Subtotal	12,847	14,760
Less:		
Other, including unamortized discounts and premiums	33	71
Current maturities	331	1,360
Total long-term financing obligations, less current maturities	$ 12,483	$ 13,329

Changes in Long-Term Financing Obligations. During 2007, we had the following changes in our long-term financing obligations:

Company	**Interest Rate**	**Book Value Increase (Decrease)**	**Cash Received / (Paid)**
Issuances			
EPEP			
Revolving credit facility due 2012	variable	$ 955	$ 952
El Paso			
Revolving credit facility due 2012	variable	3,125	3,117
Notes due 2014	6.875%	374	371

Notes due 2017	7.00%		893		886
EPNG notes due 2017	5.95%		354		350
El Paso Pipeline Partners, L.P.					
Revolving credit facility due 2012	variable		455		454
SNG notes due 2017	5.90%		500		494
Increases through December 31, 2007		$	6,656	$	6,624
Repayments, repurchases and other					
El Paso	6.375%-10.75%	$	(3,001)	$	(3,175)
El Paso-Euro	7.125%		(157)		(165)
EPEP	7.75%		(1,199)		(1,267)
SNG	6.70%		(100)		(100)
SNG	8.875%		(398)		(418)
SNG	6.125%		(66)		(66)
CIG	5.95%		(125)		(127)
EPNG	7.625%		(299)		(314)
Other	various		64		(20)
			(5,281)		(5,652)

	Interest Rate	Book Value Increase (Decrease)		Cash Received / (Paid)
Revolving Credit Facilities				
EPEP	variable	(350)		(350)
El Paso	variable	(2,900)		(2,900)
Decreases through December 31, 2007		$	(8,531)	$ (8,902)

During 2007, we recorded $291 million of pre-tax losses on the extinguishment of certain debt obligations repurchased and debt refinanced above.

Prior to their redemption in 2006, we recorded accretion expense on our zero coupon debentures, which increased the principal balance of long-term debt each period. During 2006 and 2005, the accretion recorded in interest expense was $4 million and $25 million. During 2006 and 2005, we redeemed $615 million and $236 million of our zero coupon convertible debentures, of which $110 million and $34 million represented increased principal due to the accretion of interest on the debentures. We account for these redemptions as financing activities in our statement of cash flows.

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):

2008	$ 331
2009	1,095
2010	251
2011	643
2012	2,075
Thereafter	8,452
Total long-term financing obligations, including current maturities	$ 12,847

Credit Facilities/Letters of Credit

As of December 31, 2007, subject to the terms of various agreements, we had available capacity under such credit agreements of approximately $1.0 billion, exclusive of capacity on the El Paso Pipeline Partners, L.P. (EPPP) facility further discussed below. Below is a description of our existing credit facilities as of December 31, 2007:

$1.5 Billion Revolving Credit Agreement. In November 2007, we restructured our $1.75 billion credit agreement to eliminate the $0.5 billion deposit letter of credit facility and to increase the revolving credit facility from $1.25 billion to $1.5 billion. El Paso and certain of its subsidiaries have guaranteed the $1.5 billion revolving credit agreement, which is collateralized by our stock ownership in EPNG and TGP who are also eligible borrowers under the $1.5 billion revolving credit agreement.

Under the $1.5 billion revolving credit facility which matures in November 2012, we can borrow funds at LIBOR plus 1.25% based on a current applicable margin or issue letters of credit at 1.375% of the amount issued. We pay an annual commitment fee of 0.25% (based on a current applicable margin) on any unused capacity under the revolving credit facility. Under the credit agreement, the applicable margin used to calculate interest on borrowings, letters of credit and commitment fees is determined by a variable pricing grid tied to the credit ratings of our senior secured debt. As of December 31, 2007, we had approximately $0.3 billion of letters of credit issued and $0.4 billion of debt outstanding under this facility.

Unsecured Revolving Credit Facility. We have a $500 million unsecured revolving credit facility that matures in July 2011 with a third party and a third party trust that provides for both borrowings and issuing letters of credit. We are required to pay fixed facility fees at a rate of 2.34% on the total committed amount of the facility. In addition, we will pay interest on any borrowings at a rate comprised of either LIBOR or a base rate. Substantially all of the capacity under this facility was used to issue letters of credit.

Unsecured Credit Facility. In June 2007, we entered into a $150 million unsecured facility that provides for both borrowings and issuing letters of credit. As of December 31, 2007, we had increased the capacity under this facility to $500 million. The facility matures in various tranches during 2009. Based on this facility size, we are required to pay a fixed facility fee at a weighted average rate of 1.58% per annum on the full facility amount. Borrowings carry an interest rate of LIBOR in addition to the facility fee. Substantially all of the capacity under the facility has been used to issue letters of credit.

EPEP $1.0 Billion Revolving Credit Agreement. In September 2007, we amended and restated EPEP s revolving credit facility, increasing the capacity by $0.5 billion to $1.0 billion. The other material terms and conditions of this facility remain the same. As of December 31, 2007, we had $0.8 billion outstanding under this facility. Based on current borrowing levels, we pay interest at LIBOR plus 1.25% on borrowings, and a commitment fee of 0.30% on any unused capacity. This facility is collateralized by certain of our natural gas and oil properties, which are subject to revaluation on a semi-annual basis. As of December 31, 2007, the most recent determination was sufficient to fully support this facility.

Contingent Letter of Credit Facility. We have a $250 million unsecured contingent letter of credit facility that matures in March 2008. Letters of credit are available to us under the facility if the average NYMEX gas price strip for the remaining calendar months through March 2008 is equal to or exceeds $11.75 per MMBtu. The facility fee, if triggered, is 1.66% per annum.

El Paso Pipeline Partners, L.P. Revolving Credit Facility. In November 2007, EPPP and WIC, their subsidiary, entered into an unsecured 5-year revolving credit facility with an initial aggregate borrowing capacity of up to $750 million expandable to $1.25 billion for certain expansion projects and acquisitions. This facility is only available to EPPP and its subsidiaries and borrowings are guaranteed by EPPP or its subsidiaries. Amounts borrowed are non-recourse to El Paso. Approximately $455 million was outstanding under the credit facility as of December 31, 2007. The credit facility has two pricing grids, one based on credit ratings and the other based on leverage. Currently, the leverage pricing grid is in effect and EPPP s cost of borrowings is LIBOR plus 0.525% based on EPPP s current leverage. EPPP also pays a 0.125% annual commitment fee for this facility.

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, 2007, we had outstanding letters of credit of approximately $1.3 billion. Included in this amount is $1.0 billion of letters of credit securing our recorded obligations related to price risk management activities.

Restrictive Covenants

$1.5 billion Revolving Credit Agreement. Our covenants under the $1.5 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 and cross-acceleration. 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 most restrictive debt covenants and cross default provisions are:

(a) Our ratio of Debt to Consolidated EBITDA, each as defined in the credit agreement, shall not exceed 5.5 to 1 at anytime prior to June 30, 2008. Thereafter it shall not exceed 5.25 to 1 until maturity;

(b) Our ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense plus dividends paid shall not be less than 1.75 to 1 at anytime prior to June 30, 2008. Thereafter it shall not be less than 2.00 to 1 until maturity;

(c) EPNG and TGP 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; and

(d) 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.

EPEP $1.0 Billion Revolving Credit Agreement. EPEP s borrowings under this facility are subject to various conditions. The financial coverage ratio under the facility requires that EPEP s EBITDA, as defined in the facility, to interest expense not be less than 2.0 to 1 and EPEP s debt to EBITDA, each as defined in the credit agreement, must not exceed 4.0 to 1.

EPPP Revolving Credit Facility. EPPP s borrowings under the credit facility contains covenants and provisions, the most restrictive of which requires EPPP to maintain, as of the end of each fiscal quarter, a consolidated leverage ratio (consolidated indebtedness to consolidated EBITDA (as defined in the credit facility)) of less than 5.0 to 1.0 for any four consecutive quarters; and 5.5 to 1.0 for any three consecutive quarters subsequent to the consummation of specified permitted acquisitions having a value greater than $25 million. EPPP has also added additional flexibility to their covenants for growth projects. In case of a capital construction or expansion project in excess of $20 million, adjustments to consolidated EBITDA, approved by the lenders, may be made based on the percentage of capital costs expended and projected cash flows for the project. Such adjustments shall be limited to 25% of actual EBITDA.

Other Restrictions and Provisions. In addition to the above restrictions and 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 ability 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. Our most restrictive acceleration provision is $10 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 $10 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.

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

Other Financing Arrangements

Capital Trusts. El Paso Energy Capital Trust I (Trust I), is a wholly owned business trust formed in March 1998 that issued 6.5 million of 4.75 percent trust convertible preferred securities 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, which are 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.

Non-Recourse Project Financings. Several of our subsidiaries and investments have debt obligations related to their costs of construction or acquisition. This project financing debt is recourse only to the project company and assets (i.e. without recourse to El Paso). As of December 31, 2007, two international power projects accounted for as equity investments are in default under their debt agreements; however, we have no material exposure as a result of these defaults.

12. Commitments and Contingencies

Legal Proceedings

ERISA Class Action Suit. 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 that our communication with participants in our Retirement Savings Plan included various 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). Various motions have been filed and we are awaiting the court s ruling. We have insurance coverage for this lawsuit, subject to certain deductibles and co-pay obligations. We have established accruals for this matter which we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a purported class action 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 alleges various violations of ERISA and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. Certain of the claims that our cash balance plan violated ERISA were recently dismissed by the trial court. Our costs and legal exposure related to this lawsuit are not currently determinable.

Shareholder Litigation. In 2007, we settled twenty-eight shareholder class action lawsuits that had alleged violations of federal securities laws by us and several of our current and former officers and directors. Under the settlement, we contributed approximately $48 million, our insurers contributed approximately $225 million, and a third party contributed $12 million.

Retiree Medical Benefits Matters. We 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 July 1, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off in 1994. Tenneco retained an obligation to provide certain medical benefits at the time of the spin-off and we assumed this obligation as a result of our merger with Tenneco. Pursuant to an agreement with the applicable union for Case employees, our liability for these benefits was subject to a cap, such that costs in excess of the cap were to be assumed by plan participants. In 2002, we and Case were sued by individual retirees in a 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 was obligated to indemnify Case 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 by the U.S. Court of Appeals for the 6th Circuit. In October 2007, pending a trial on the merits, the court expanded the number of retirees covered by its prior preliminary rulings. We will proceed with a trial on the merits with regard to the issues of whether the cap is enforceable and to what degree benefits have actually vested. Until this is resolved, El Paso will indemnify Case for payments Case makes above the cap, which are currently about $2 million per month. We continue to defend the action and have 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. 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 obligation. We have established an accrual for this matter which we believe is adequate and further discussed in guarantees and indemnifications below.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging 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 cases were consolidated in federal court in New York for all pre-trial purposes and were styled In re: Gas Commodity Litigation. 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. A settlement was finalized and has been paid. The second set of cases, involving similar allegations on behalf of commercial and residential customers, was transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada and styled In re: Western States Wholesale Natural Gas Antitrust Litigation. These cases were dismissed. The U.S. Court of Appeals for the Ninth Circuit, however, reversed the dismissal and ordered that these cases be remanded to the trial court. A petition for certiorari has been filed with the U.S. Supreme Court. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include Farmland Industries v. Oneok Inc., et al. (filed in state court in Wyandotte County, Kansas in July 2005) and Missouri Public Service Commission v. El Paso Corporation, et al. (filed in the circuit court of Jackson County, Missouri at Kansas City in October 2006), and the purported class action lawsuits styled: Leggett, et al. v. Duke Energy Corporation, et al. (filed in Chancery Court of Tennessee in January 2005); Ever-Bloom Inc., et al. v. AEP Energy Services Inc., et al. (filed in federal court for the Eastern District of California in September 2005); Learjet, Inc., et al. v. Oneok Inc., et al. (filed in state court in Wyandotte County, Kansas in September 2005); Breckenridge, et al. v. Oneok Inc., et al. (filed in state court in Denver County, Colorado in May 2006); Arandell, et al. v. Xcel Energy, et al. (filed in the circuit court of Dane County, Wisconsin in December 2006); and Heartland, et al. v. Oneok Inc., et al. (filed in the circuit court of Buchanan County, Missouri in March 2007). The Leggett case was dismissed by the Tennessee state court and has been appealed. The remaining cases have all been transferred to the MDL proceeding. The Missouri Public Service case has been remanded to state court. Dispositive motions have been filed or are anticipated to be filed in these cases. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Gas Measurement Cases. A number of our subsidiaries were named defendants in actions that generally allege mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act, which have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming). 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. In October 2006, the U.S. District Judge issued an order dismissing all claims against all defendants. An appeal has been filed.

Similar allegations were filed in a set of actions initiated in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The plaintiffs currently seek certification of a class of royalty owners in wells on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. Motions for class certification have been briefed and argued in the proceedings and the parties are awaiting the court s ruling. The plaintiff seeks an unspecified amount of monetary damages in the form of additional royalty payments (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. Our costs and legal exposure related to these lawsuits and claim are not currently determinable.

MTBE. 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 the potential impact of MTBE on water supplies. Some of our subsidiaries are among the defendants in approximately 80 such lawsuits. The plaintiffs, certain state attorneys general, various water districts and a limited number of individual water customers, generally seek remediation of their groundwater, prevention of future contamination, damages (including natural resource 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. Although these suits had been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York, a recent appellate court decision directed two of the cases to be remanded back to state court. A limited number of cases have since been remanded to separate state court proceedings. It is possible many of the other cases will also be remanded. We have reached an agreement in principle with the plaintiffs to settle approximately 60 of the lawsuits. We have also reached an agreement in principle with our insurers, whereby our insurers would fund substantially all of the consideration to be provided by our subsidiaries under the terms of the settlement with the plaintiffs. Approximately 20 of the remaining lawsuits are not covered by the terms of this settlement. While the damages claimed in these remaining actions are substantial there remains significant legal uncertainty regarding the validity of the causes of action asserted and the availability of the relief sought by the plaintiffs. We have tendered these remaining cases to our insurers. Our costs and legal exposure related to these remaining lawsuits are not currently determinable.

Government Investigations and Inquiries

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 continue to cooperate with the SEC in its investigation related to such reserve revisions. We originally self-reported this matter to the SEC and have been cooperating fully with the investigation, which has included producing a large volume of documents and making our employees available for interviews or testimony upon request. On July 13, 2007, we received a notice indicating the SEC staff has made a preliminary decision to recommend to the SEC that it institute an enforcement action against us and two of our subsidiaries related to the reserve revisions. We understand that the staff of the SEC may have also issued similar notices to several of our former employees related to the reserves revisions. We were given the opportunity to respond to the staff before it makes its formal recommendation on whether any action should be brought by the SEC, and on September 25, 2007 we submitted our response.

Legacy Crude Oil Trading. In 2007, we recorded $77 million of other income in our income statement related to the reversal of amounts accrued prior to 2001 relating to shipments of crude oil allegedly purchased by Coastal in 1990. We reversed these amounts following the expiration of the related statute of limitation periods and the completion of a review of the matter and related defenses.

In addition to the above proceedings, 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. For each of these 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, including those 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. It is possible, however, 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, 2007, we had approximately $460 million accrued, net of related insurance receivables, for our outstanding legal and governmental proceedings.

Rates and Regulatory Matters

Notice of Inquiry on Pipeline Fuel Retention Policies. In September 2007, the FERC issued a Notice of Inquiry regarding its policy about the in-kind recovery of fuel and lost and unaccounted for gas by natural gas pipeline companies. Under current policy, pipelines have options for recovering these costs. For some pipelines, the tariff states a fixed percentage as a non-negotiable fee-in-kind retained from the volumes tendered for shipment by each shipper. There is also a tracker approach, where the pipeline s tariff provides for prospective adjustments to the fuel retention rates from time-to-time, but does not include a mechanism to allow the pipeline to reconcile past over or under-recoveries of fuel. Finally, some pipelines tariffs provide for a tracker with a true-up approach, where provisions in a pipeline s tariff allow for periodic adjustments to the fuel retention rates, and also provide for a true-up of past over and under-recoveries of fuel and lost and unaccounted for gas. In this proceeding, the FERC is seeking comments on whether it should change its current policy and prescribe a uniform method for all pipelines to use in recovering these costs. Our pipeline subsidiaries currently utilize a variety of these methodologies. At this time, we do not know what impact this proceeding may ultimately have on any of us.

Notice of Proposed Rulemaking. On October 3, 2007, the Minerals Management Service (MMS) issued a Notice of Proposed Rulemaking for Oil and Gas and Sulphur Operations in the Outer Continental Shelf Pipelines and Pipeline Rights-of-Way . If adopted, the proposed rules would substantially revise MMS Outer Continental Shelf (OCS) pipeline and rights-of-way (ROW) regulations. The proposed rules would have the effect of: (1) increasing the financial obligations of entities, like us, which have pipelines and pipeline rights-of-way in the OCS; (2) increasing the regulatory requirements imposed on the operation and maintenance of existing pipelines in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS. .

EPNG. In August 2007, EPNG received approval of the settlement of its rate case from the FERC. The settlement provides benefits for both EPNG and its customers for a three year period ending December 31, 2008. Under the terms of the settlement, EPNG is required to file a new rate case to be effective January 1, 2009. EPNG received approval from the FERC to begin billing the settlement rates on October 1, 2007. Our financial statements reflect EPNG s settled rates. Additionally, in 2007 and 2006, we recorded rate refund provisions of approximately $60 million and $65 million inclusive of interest, which we reflected as accrued liabilities on our balance sheet. In the fourth quarter of 2007, EPNG refunded $115 million including interest in rate refunds to its customers and refunded the remaining $10 million in January 2008.

Other Contingencies

Navajo Nation. Approximately 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 are the subject of a pending renewal application filed in 2005 with the Department of the Interior s Bureau of Indian Affairs. An interim agreement with the Navajo Nation expired at the end of December 2006. Negotiations on the terms of the long-term agreement are continuing. In addition, we continue to preserve other legal, regulatory and legislative 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. It is uncertain whether our negotiation, or other alternatives, will be successful, or if successful, what the ultimate cost will be of obtaining the rights-of-way and whether we will be able to recover these costs in EPNG s rates.

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. At December 31, 2007, we accrued approximately $260 million, which has not been reduced by $27 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $251 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $9 million for related environmental legal costs. Of the $260 million accrual, $22 million was reserved for facilities we currently operate and $238 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $260 million to approximately $470 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 ($18 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($242 million to $452 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. Our recorded liabilities 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:

	December 31, 2007	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 22	$ 28
Non-operating	211	393
Superfund	27	49
Total	$ 260	$ 470

Below is a reconciliation of our accrued liability from January 1, 2007 to December 31, 2007 (in millions):

Balance as of January 1, 2007	$ 314
Additions/adjustments for remediation activities	21
Payments for remediation activities	(75)
Balance as of December 31, 2007	$ 260

For 2008, we estimate that our total remediation expenditures will be approximately $65 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 $7 million in the aggregate for the years 2008 through 2011. These expenditures primarily relate to compliance with clean air regulations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 44 active sites under the Comprehensive 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, 2007, we have estimated our share of the remediation costs at these sites to be between $27 million and $49 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and 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.

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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, operating facilities and equipment. The terms of the agreements vary from 2008 until 2053. Minimum annual rental commitments under our operating leases at December 31, 2007, were as follows:

Year Ending December 31,	**Operating Leases[(1)] (In millions)**
2008	$ 14
2009	13
2010	10
2011	7
2012	7
Thereafter	29
Total	$ 80

(1) Amounts have not been reduced by minimum sublease rentals of approximately $1 million due in the future under noncancelable subleases.

Rental expense on our lease obligations for the years ended December 31, 2007, 2006, and 2005 was $40 million, $43 million and $53 million, which includes $27 million in 2005 related to consolidating our Houston-based operations.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require 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 and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $785 million, for which we are indemnified by third parties for $15 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 11. Included in the above maximum stated value is approximately $438 million related to indemnification arrangements associated with the sale of ANR and related operations and approximately $119 million related to tax matters, related interest and other indemnifications and guarantees arising out of the sale of our Macae power facility. As of December 31, 2007, we have recorded obligations of $51 million related to our guarantees and indemnification arrangements, of which $8 million is related to ANR and related assets and Macae. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

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 $379 million associated with our estimated exposure under this matter as of December 31, 2007. 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, 2007, we had firm commitments under transportation and storage capacity contracts of $195 million due at various times and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $709 million, the substantial majority of which is due in less than one year.

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 by us (see *Navajo Nation* above).

13. 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, Inc. or The Coastal Corporation 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 2008.

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 expect to contribute $4 million to the SERP in 2008. We also maintain two other frozen pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. We do not anticipate making any contributions to our frozen pension plans in 2008. 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 2007, 2006 and 2005 were not material.

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 depending on our performance relative to our peers. Amounts expensed under this plan were approximately $16 million, $30 million and $25 million for the years ended December 31, 2007, 2006 and 2005.

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 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 $27 million to our postretirement plans in 2008. 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. On December 31, 2006, we adopted the recognition provisions of SFAS No. 158, and upon adoption we reflected the assets and liabilities related to our pension and other postretirement benefit plans based on their funded or unfunded status and all actuarial deferrals were reclassified as a component of accumulated other comprehensive income. The adoption of this standard decreased our other non-current assets by $601 million, our other non-current deferred tax liabilities by $210 million, and our accumulated other comprehensive income by $391 million. In March 2007, the FERC issued guidance requiring regulated pipeline companies to recognize a regulatory asset or liability for the funded status asset or liability that would otherwise be recorded in accumulated other comprehensive income under SFAS No. 158, if it is probable that amounts calculated on the same basis as SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions,* would be included in our rates in future periods. Upon adoption of this FERC guidance, we reclassified approximately $9 million from the beginning balance of accumulated other comprehensive income to regulatory liabilities, which is included in other non-current liabilities on our balance sheet.

The table below provides additional information related to our pension and other postretirement plans as of September 30, our measurement date, for our benefit obligations and plan assets and as of December 31 for the balance sheet amounts:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(In millions)			
Projected benefit obligation/accumulated postretirement benefit obligation	$2,027	$2,157	$418	$494

Fair value of plan assets	2,537	2,382	303	276
Current benefit liability	4	5	24	25
Non-current benefit liability	33	52	192	228
Non-current benefit asset	550	285	106	44
Accumulated other comprehensive income (loss), net of income taxes	$ (269)	$ (450)	$ 32	$ 15

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Our accumulated benefit obligation for our defined benefit pension plans was $2.0 billion and $2.1 billion as of December 31, 2007 and 2006. Our projected benefit obligation and accumulated benefit obligation for our pension plans whose accumulated benefit obligations exceeded the fair value of plan assets, was $37 million as of December 31, 2007 and $167 million as of December 31, 2006.

Our accumulated postretirement benefit obligation for our other postretirement benefit plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets was $222 million and $320 million as of December 31, 2007 and 2006.

Our accumulated other comprehensive income includes approximately $8 million of unamortized prior service costs, net of tax. We anticipate that approximately $16 million of our accumulated other comprehensive loss, net of tax, will be recognized as a part of our net periodic benefit cost in 2008.

Change in 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	
	2007	2006	2007	2006
	(In millions)			
Change in benefit obligation[1]:				
Benefit obligation beginning of period	$ 2,157	$ 2,235	$ 494	$ 527
Service cost	17	17	1	11
Interest cost	119	118	26	26
Participant contributions			32	34
Actuarial gain	(86)	(37)	(66)	(35)
Benefits paid	(186)	(176)	(69)	(69)
Other	6			
Benefit obligation end of period	$ 2,027	$ 2,157	$ 418	$ 494
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 2,382	$ 2,350	$ 276	$ 251
Actual return on plan assets[2]	333	192	39	19
Employer contributions	8	16	25	41
Participant contributions			32	34
Benefits paid	(186)	(176)	(69)	(69)
Fair value of plan assets at end of period	$ 2,537	$ 2,382	$ 303	$ 276
Reconciliation of funded status:				
Fair value of plan assets at September 30	$ 2,537	$ 2,382	$ 303	$ 276
Less: Benefit obligation end of period	2,027	2,157	418	494
Funded status at September 30	510	225	(115)	(218)
Fourth quarter contributions and income	3	3	5	9
Net asset (liability) at December 31	$ 513	$ 228	$ (110)	$ (209)

(1)

Benefit obligation in the table above refers to the projected benefit obligation for our pension plans and accumulated postretirement benefit obligation for our postretirement plans.

(2) We defer the difference between our actual return on plan assets and our expected return over a three year period, after which they are considered for inclusion in net benefit expense or income. Our deferred actuarial gains and losses are amortized only to the extent that our remaining unrecognized actual gains and losses exceed the greater of 10 percent of our projected benefit obligations or market related value of plan assets.

Expected Payment of Future Benefits. As of December 31, 2007, we expect the following payments under our plans, net of participant contributions:

Year Ending December 31	Pension Benefits	Other Postretirement Benefits[1]
	(In millions)	
2008	$167	$ 44
2009	167	43
2010	166	42
2011	164	41
2012	163	39
2013-2017	793	173

(1) Includes a reduction in each of the years presented 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		
	2007	2006	2005	2007	2006	2005
	(In millions)					
Service cost	$ 17	$ 17	$ 22	$ 1	$ 11	$ 1
Interest cost	119	118	121	26	26	29
Expected return on plan assets	(181)	(175)	(168)	(16)	(14)	(12)
Amortization of net actuarial loss	43	55	69	(1)		
Amortization of prior service cost[1]	(2)	(2)	(2)	(1)	(1)	(1)
Other		(2)	1		(1)	8
Net benefit cost (income)	$ (4)	$ 11	$ 43	$ 9	$ 21	$ 25

(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 2007, 2006 and 2005:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
	(Percent)			(Percent)		
Assumptions related to benefit obligations at September 30:						
Discount rate	6.25	5.75		6.05	5.50	
Rate of compensation increase	4.27	4.00				

Assumptions related to benefit costs for the year ended December 31:						
Discount rate	5.75	5.50	5.75	5.50	5.25	5.75
Expected return on plan assets[(1)]	8.00	8.00	8.00	8.00	8.00	7.50
Rate of compensation increase	4.00	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate of return based on our targeted portfolio of investments. Some of our postretirement benefit plans investment earnings are subject to unrelated business income tax at a rate of 35%. The expected return on plan assets for our postretirement benefit plans is calculated using the after-tax rate of return.

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 9.4 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:

	2007	**2006**
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	13	18
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(12)	(15)

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Plan Assets. 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 meet the benefit obligations to participants, retirees and beneficiaries exists. 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. 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 2007**	**Actual 2006**	**Target**	**Actual 2007**	**Actual 2006**
		(Percent)			**(Percent)**	
Equity securities	60	67	66	65	63	63
Debt securities	40	32	33	35	33	33
Other		1	1		4	4
Total	100	100	100	100	100	100

Other Matters. A trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits paid to a closed group of 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 12.

14. Stockholders Equity and Minority Interest

Stockholders Equity

Common Stock. In 2006, we issued 35.7 million shares of common stock for net proceeds of approximately $500 million. In 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 2005, we issued $750 million of convertible perpetual preferred stock. Dividends on the preferred stock are declared quarterly at the rate of 4.99% per annum if approved by our Board of Directors and dividends accumulate if not 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 five years after issuance if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds from the issuance of the preferred stock, along with cash on hand, was used to settle litigation of approximately $442 million and to redeem all of the 6 million outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Company for approximately $300 million.

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

	Common Stock ($0.16/share)	**Convertible Preferred Stock (4.99%/year)**
Amount paid in 2007	$ 112	$ 37
Amount paid in January 2008	$ 28	$ 9

Declared in 2008:

Date of declaration	February 7, 2008	February 7, 2008
Payable to shareholders on record	March 7, 2008	March 15, 2008
Date payable	April 1, 2008	April 1, 2008

Dividends on our common stock and preferred 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 2007 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.

Accumulated Other Comprehensive Income. The following table provides the components of our accumulated other comprehensive income (loss) as of December 31:

	2007	2006
Cash flow hedges (see Note 7)	$ (35)	$ 80
Pension and other postretirement benefits (see Note 13)	(237)	(435)
Investments available for sale		12
Total accumulated other comprehensive loss, net of income taxes	$ (272)	$ (343)

Minority Interest

In November 2007, we issued common units in our subsidiary El Paso Pipeline Partners, L.P., a master limited partnership and accordingly recorded minority interest on our balance sheet of $537 million. Under its partnership agreement, the MLP is obligated to distribute available cash as defined in the agreement. Currently, the MLP s minimum quarterly distribution on its common units is $0.2875/unit per quarter.

15. Stock-Based Compensation

Overview. 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. 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, 2007, approximately 29 million shares remain available for grant under our current plans. In addition, we have approximately 18 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

We record stock-based compensation expense, excluding amounts capitalized, as operation and maintenance expense over the requisite service period for each separately vesting portion of the award, net of estimates of forfeitures. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods.

Non-Qualified Stock Options. We grant non-qualified stock options to our employees with an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally vest in equal amounts over three years from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the year ended December 31, 2007 is presented below:

	# Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)

Outstanding at December 31, 2006	24,135,442	$35.52		
Granted	4,931,457	$14.77		
Exercised	(768,867)	$ 8.85		
Forfeited or canceled	(1,347,888)	$12.52		
Expired	(2,966,149)	$47.32		
Outstanding at December 31, 2007	23,983,995	$31.93	5.03	$ 72
Vested at December 31, 2007 or expected to vest in the future	23,590,686	$32.25	4.97	$ 70
Exercisable at December 31, 2007	16,117,816	$41.23	3.36	$ 37

In 2007 and 2006, we recognized $16 million and $11 million of pre-tax compensation expense on stock options, capitalized approximately $4 million and $2 million of this expense in each respective year as part of fixed assets and recorded $6 million and $4 million of income tax benefits. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2007 was approximately $16 million, which is expected to be recognized over a weighted average period of 10 months. Options exercised during the year ended December 31, 2007 and 2006 had a total intrinsic value of approximately $6 million and $5 million, generated $7 million and $6 million of cash proceeds and did not generate any significant associated income tax benefit. The total intrinsic value, cash received and income tax benefit generated from option exercises was not material during the year ended December 31, 2005.

Fair Value Assumptions. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management s best estimate at the time of grant. For the years ended December 31, 2007, 2006 and 2005 the weighted average grant date fair value per share of options granted was $5.53, $4.89, and $3.88.

Listed below is the weighted average of each assumption based on grants in each fiscal year:

	2007	**2006**	**2005**
Expected Term in Years	6.0	6.0	4.8
Expected Volatility	34%	38%	42%
Expected Dividends	1%	1.3%	1.5%
Risk-Free Interest Rate	4.6%	4.9%	3.7%

We estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and our historical stock price volatility over the expected term, adjusted for certain time periods that we believe are not representative of future stock performance. Prior to January 1, 2006, we estimated expected volatility based primarily on adjusted historical stock price volatility. Effective January 1, 2006, we adopted the provisions of SEC Staff Accounting Bulletin (SAB) No. 107 and estimate the expected term of our option awards based on the vesting period and average remaining contractual term. We expect to continue to use this approach for all stock option contracts consistent with SEC SAB No. 110, *Share Based Payment*, which allows us to continue the use of the simplified method in estimating our expected term consistent with the manner in which we determined expected term under SAB 107. We use this method due to a lack of sufficient historical data to provide a reasonable basis for estimating our expected term based on significant changes in the composition of our employees receiving stock-based compensation awards over the last several years.

Restricted Stock. We may grant shares of restricted common stock, which carry voting and dividend rights, to our officers and employees. Sale or transfer of these shares is restricted until they vest. We currently have outstanding and grant time-based restricted stock. The fair value of our time-based restricted shares is determined on the grant date and these shares generally vest in equal amounts over three years from the date of grant. A summary of the changes in our non-vested restricted shares for each fiscal years are presented below:

Nonvested Shares	**# Shares**	**Weighted Average Grant Date Fair Value per Share**
Nonvested at December 31, 2006	3,739,220	$ 11.44
Granted	2,541,836	$ 14.73
Vested	(1,765,800)	$ 10.43
Forfeited	(599,316)	$ 13.38
Nonvested at December 31, 2007	3,915,940	$ 13.74

The weighted average grant date fair value per share for restricted stock granted during 2007, 2006 and 2005 was $14.73, $13.09 and $10.78. The total fair value of shares vested during 2007, 2006 and 2005 was $31 million,

$24 million, and $14 million.

During 2007, 2006 and 2005, we recognized approximately $25 million, $17 million and $18 million of pre-tax compensation expense on our restricted share awards, capitalized approximately $7 million in 2007 and $2 million in 2006 and 2005 as part of fixed assets and recorded $9 million, $6 million and $6 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2007 was approximately $24 million, which is expected to be recognized over a weighted average period of 10 months.

Employee Stock Purchase Plan. Our employee stock purchase plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of SFAS No. 123(R). Shares issued under this plan were insignificant during 2007, 2006 and 2005.

16. Business Segment Information

As of December 31, 2007, our business consists of two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Prior to 2006, we also had a Field Services segment. 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 activities include our general and administrative functions, as well as other miscellaneous businesses and various other contracts and assets, all of which are immaterial. A further discussion of each segment follows.

Pipelines. Provides natural gas transmission, storage, and related services, primarily in the United States. As of December 31, 2007, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in three interstate transmission systems, along with two underground natural gas storage entities and an LNG terminalling facility.

Exploration and Production. Engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States, Brazil and Egypt.

Marketing. Markets and manages the price risks associated with our natural gas and oil production as well as our remaining legacy trading portfolio.

Power. Manages the risks associated with our remaining international power assets, primarily in Brazil, Asia and Central America. We continue to pursue the sale of these assets.

Prior to January 1, 2006, we had a Field Services segment which conducted midstream activities. We have disposed of substantially all of the assets in this segment.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2007, 2006 and 2005.

Our management uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense 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 from continuing operations for the periods ended December 31:

	2007	2006	2005
		(In millions)	
Segment EBIT	$ 1,935	$ 1,838	$ 979
Corporate and other	(283)	(88)	(521)
Interest and debt expense	(994)	(1,228)	(1,295)
Income taxes	(222)	9	331
Income (loss) from continuing operations	$ 436	$ 531	$ (506)

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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, 2007					
	Segment					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[(1)]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,429	$ 1,123(2)	$ 814	$	$ 54	$ 4,420
Foreign	11	17(2)	163		37	228
Intersegment revenue	54	1,160(2)	(1,196)		(18)	
Operation and maintenance	753	439	11	17	113	1,333
Depreciation, depletion and amortization	373	780	3	1	19	1,176
Earnings (losses) from unconsolidated affiliates	105	11		(15)		101
EBIT	1,265	909	(202)	(37)	(283)[(5)]	1,652
Discontinued operations, net of income taxes	674					674
Assets of continuing operations						
Domestic	13,764	7,404	506	5	1,482	23,161
Foreign[(3)]	175	625	31	526	61	1,418
Capital expenditures and investments in and advances to unconsolidated affiliates, net[(4)]	1,059	2,613		(34)	7	3,645
Total investments in unconsolidated affiliates	759	704		151		1,614

(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 $19 million and an operation and maintenance expense elimination of $1 million, which is included in the Corporate column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Of total foreign assets, approximately $0.6 billion relates to property, plant and equipment, and

approximately $0.6 billion relates to investments in and advances to unconsolidated affiliates.

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

(5) Includes debt extinguishment costs of $86 million related to refinancing EPEP s $1.2 billion notes.

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	As of or for the Year Ended December 31, 2006					
	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate[1] and Other	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,331	$ 645(2)	$ 1,012	$ 4	$ 116	$ 4,108
Foreign	10	32(2)	131			173
Intersegment revenue	61	1,177(2)	(1,201)	2	(39)	
Operation and maintenance	743	410	28	57	99	1,337
Depreciation, depletion and amortization	370	645	4	2	26	1,047
Earnings from unconsolidated affiliates	90	10		45		145
EBIT	1,187	640	(71)	82	(88)	1,750
Discontinued operations, net of income taxes	118			(27)	(147)	(56)
Assets of continuing operations[3]						
Domestic	12,958	5,858	1,115		1,950	21,881
Foreign[4]	147	404	28	618	50	1,247
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[5]	1,023	1,113		(44)	14	2,106
Total investments in unconsolidated affiliates	757	729		221		1,707

(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 $37 million and an operation and maintenance expense elimination of $13 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 segment, which is responsible for marketing our production to third parties.

(3) Excludes assets of discontinued operations of $4,133 million (see Note 2).

(4) Approximately $0.4 billion of total foreign assets relates to

property, plant and equipment and approximately $0.7 billion relates to investments in and advances to unconsolidated affiliates.

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

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	As of or for the Year Ended December 31, 2005 Segments						
	Pipelines	Exploration and Production	Marketing	Power (In millions)	Field Services	Corporate[(1)] and Other	Total
Revenue from external customers							
Domestic	$ 2,094	$ 466(2)	$ 411	$ 71	$ 96	$ 85	$ 3,223
Foreign	7	54(2)	3				64
Intersegment revenue	70	1,267(2)	(1,210)	11	27	(93)	72(3)
Operation and maintenance	772	383	54	122	37	567	1,935
Depreciation, depletion and amortization	343	612	4	2	3	42	1,006
Earnings (losses) from unconsolidated affiliates	100	19		(139)	301		281
EBIT	924	696	(837)	(89)	285	(521)	458
Discontinued operations, net of income taxes	154	9		(476)	251	(34)	(96)
Assets of continuing operations[(4)]							
Domestic	12,264	5,215	3,786	70	99	4,081	25,515
Foreign[(5)]	125	355	33	1,106		57	1,676
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[(6)]	780	1,851		5	8	14	2,658
Total investments in unconsolidated affiliates	734	761		670			2,165

(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 segment, which is responsible for marketing our production to third parties.

(3) Relates to intercompany activities

between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $4,649 million.

(5) Of total foreign assets, approximately $0.3 billion 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.

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17. 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 and impairment charges recorded by us. As of December 31, 2007 and 2006, our investment balance exceeded the net equity in the underlying net assets of these investments by $377 million and $409 million due to these items. The majority of our purchase price adjustments is related to our investment in Four Star which we acquired in 2005. We generally amortize and assess the recoverability of this amount based on the development and production of the underlying estimated proved natural gas and oil reserves of Four Star. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the years ended December 31:

	Net Ownership Interest		Investment		Earnings (Losses) from Unconsolidated Affiliates		
	2007	2006	2007	2006	2007	2006	2005
	(Percent)		(In millions)			(In millions)	
Domestic:							
Four Star[(1)]	49	43	$ 698	$ 723	$ 12	$ 10	$ 19
Citrus	50	50	576	597	81	62	66
Enterprise Products Partners[(2)]							183
Midland Cogeneration Venture[(2)]						13	(162)
Javelina[(2)]							121
Other Domestic Investments	various	various	38	36	3	3	17
Total domestic			1,312	1,356	96	88	244
Foreign:							
Bolivia to Brazil Pipeline	8	8	105	105	11	11	20
Gasoductos de Chihuahua	50	50	146	126	21	25	19
Habibullah Power[(3)]	50	50	17	17		1	(13)
Manaus/Rio Negro[(4)]	100	100	56	96	(6)	17	19
Porto Velho[(3)]	50	50	(60)	(34)	(23)	2	(16)
Korea Independent Energy Corporation[(2)]							127
EGE Itabo[(2)]						1	(58)
Other Foreign Investments	various	various	38	41	2		(61)
Total foreign			302	351	5	57	37
Total investments in unconsolidated affiliates			$ 1,614	$ 1,707			
Total earnings from unconsolidated affiliates					$ 101	$ 145	$ 281

(1) Amortization of our purchase

cost in excess of the underlying net assets of Four Star was $53 million, $54 million and $20 million during 2007, 2006 and 2005. During the third quarter of 2007, we paid $27 million to increase our ownership interest in Four Star from 43 percent to 49 percent.

(2) We sold our interests in these investments.

(3) As of December 31, 2007 and 2006, we had outstanding advances and receivables not included in these balances of $350 million and $413 million related to our foreign investments of which $12 million and $25 million related to our investment in Habibullah Power, $335 million and $350 million relate to our investment in

Porto Velho, and the remainder in our other foreign investments. We recognized interest income on these outstanding advances and receivables of approximately $1 million, $46 million, and $47 million in 2007, 2006 and 2005. For a further discussion of these receivables, see *Matters that Could Impact Our Investments* below.

(4) We transferred ownership of these plants to the power purchaser in January 2008. For a further discussion, see *Matters that Could Impact Our Investments* below.

Impairment charges and gains and losses on sales of equity investments are included in earnings from unconsolidated affiliates. During 2007, 2006 and 2005, our impairments and gains and losses were primarily a result of our decision to sell a number of these investments or were based on declines in their fair value of the investments due to changes in economics of the investments underlying contracts, or the markets they serve. These gains (losses) consisted of the following:

Investment or Group	2007	2006	2005
		(In millions)	
Midland Cogeneration Venture[1]	$	$ 13	$ (162)
Asia power investments	(1)	(8)	(64)
Porto Velho[2]	(32)		
Manaus and Rio Negro	(15)		
Central and other South American power investments	(2)	1	(89)
Enterprise			183
Javelina			111
KIECO			108
Other			4
	$ (50)	$ 6	$ 91

(1) Amounts represent our proportionate share of losses from our investment in MCV in 2005 primarily based on MCV s impairment of the plant assets, and a gain on the sale in 2006.

(2) Amount does not include a $25 million impairment of our note receivable in 2007 as further described in *Matters that Could Impact Our Investments,* 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,		
	2007	2006	2005
	(In millions)		
Operating results data:			
Operating revenues	$ 872	$1,101	$1,476
Operating expenses	528	741	1,407
Income (loss) from continuing operations	211	174	(163)
Net income (loss)[(1)]	211	174	(163)
Financial position data:[(2)]			
Current assets	$ 390	$ 441	$ 942
Non-current assets	2,323	2,408	3,423
Short-term debt	41	82	242
Other current liabilities	328	321	441
Long-term debt	519	556	1,171
Other non-current liabilities	588	592	632
Minority interests			83
Redeemable preferred stock			9
Equity in net assets	1,237	1,298	1,787

(1) Includes net income (loss) of $(1) million, $20 million and $15 million in 2007, 2006 and 2005, related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

(2) Includes total assets of $190 million and $417 million as of December 31, 2007 and 2006 related to our proportionate share of affiliates in which we hold greater than a

50 percent interest.

We received distributions and dividends of $223 million and $177 million in 2007 and 2006, which includes $34 million and $38 million of returns of capital from our investments.

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

	2007	2006	2005
		(In millions)	
Operating revenue[(1)]	$7	$64	$114
Cost of sales	5	3	7
Other income	4	6	9
Interest income[(2)]	1	46	47

(1) Decrease primarily due to the sale of investments in our Power segment.

(2) Decrease primarily due to the impairment of our Porto Velho note receivable in 2007 as further described below.

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Accounts Receivable Sales Program. Several of our pipeline subsidiaries have agreements to sell certain accounts receivable to qualifying special purpose entities (QSPEs) under SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* As of December 31, 2007 and 2006, we sold approximately $189 million and $202 million, of receivables, received cash of approximately $79 million and $108 million, received subordinated beneficial interests of approximately $107 million and $91 million, and recognized a loss of approximately $3 million in both years. In conjunction with the sale, the QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $80 million and $111 million as of December 31, 2007 and 2006. We reflect the subordinated beneficial interest in receivables sold as accounts receivable from affiliates in our balance sheet. We reflect accounts receivable sold under this program and changes in the subordinated beneficial interests as operating cash flows in our statement of cash flows. Under the agreements, we earn a fee for servicing the accounts receivable and performing all administrative duties for the QSPEs which is reflected as a reduction of operation and maintenance expense in our income statement. The fair value of these servicing and administrative agreements as well as the fees earned were not material to our financial statements for the years ended December 31, 2007 and 2006.

Matters that Could Impact Our Investments

International Power. During 2006, we completed the sales of our in domestic power facilities and, accordingly, our remaining power investments are in international power facilities. As of December 31, 2007, we had equity investments in six power generation and transmission facilities in Asia, Central America, and Brazil that are considered variable interests under FIN No. 46(R). We operate 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. Additionally, the long-term debt issued by these entities is recourse only to the project. We have investments in and advances to these entities as well as guarantees and other agreements which are as follows at December 31, 2007:

Porto Velho. We have an equity investment in and a note receivable from the Porto Velho project in Brazil. The power generated by the Porto Velho project is committed to a state-owned utility under power purchase agreements, the largest of which extends through 2023. In July 2007, we received an offer from our partner to purchase our investment in the project for less than its overall carrying value. Our discussions with our partner about this offer have been temporarily suspended pending the resolution of certain claims with the state-owned utility, which are further described below, and a decision to sell our investment has not been made at this time. The power markets in Brazil continue to evolve and mature, and during the third quarter of 2007, the Brazilian national power grid operator communicated to Porto Velho s management that its power plant (and the region that the plant serves) will be interconnected to an integrated power grid in Brazil as soon as late 2008. When the interconnection is completed, the state-owned utility will have access to sources of power at rates that may be less than the price under Porto Velho s existing power purchase agreements. Furthermore, there are plans to construct new hydroelectric plants in northern Brazil that could reportedly be completed as early as 2012 which, once connected to the grid, could further reduce regional power prices and the amount of power Porto Velho will be able to sell under its power purchase agreements. Based on our assessment of the impact these ongoing developments may have on northern Brazil s electricity markets and Porto Velho s power purchase agreements, we recorded incremental losses on our investment during 2007 of approximately $32 million. We also recorded a $25 million impairment of our note receivable from the project, and have discontinued accruing interest on the note. After these adjustments, our total investment in the Porto Velho project was approximately $275 million as of December 31, 2007, comprised primarily of the note receivable from the project. In February 2008, we received a dividend from the project of approximately $29 million, and we and our partner extended the date upon which we will be required to convert approximately $80 million of the amounts due under this note into an equity investment in the project until July 2008. In addition, we may be required to convert up to an additional $80 million of the note in July 2008, depending on the level of equity that our partner contributes to the project, which would increase our percentage ownership in Porto Velho.

In December 2006, the Brazilian tax authorities assessed a $30 million fine against the Porto Velho power project for allegedly not filing the proper tax forms related to the delivery of fuel to the power facility under its power purchase agreements. We believe the claim by the tax authorities is without merit. In addition, beginning in the fourth quarter of 2007, the state-owned utility made claims against the Porto Velho project for the period of 2003 through

2007 totaling approximately $60 million related to alleged excess fuel consumption. We believe that we have valid defenses to these fuel claims. The state-owned utility has made additional net claims of $30 million for retroactive currency indexation adjustments, which are partially offset by retroactive revenue surcharges for periods when the plant uses oil for fuel. We are currently evaluating this claim. Further adverse developments in the Brazilian power markets or at the project could impact our ability to recover our remaining investment in the future.

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Manaus /Rio Negro. On January 15, 2008, we transferred our ownership in the Manaus and Rio Negro facilities to the plants power purchaser as required by their power purchase agreements. On the transfer date, we have approximately $69 million of accounts receivable owed to us under the projects terminated power purchase agreements, which are guaranteed by the purchaser s parent. The purchaser has withheld payment of these receivables in light of a dispute over approximately $54 million of maintenance and other items that the purchaser claims should have been performed at the plants prior to the transfer. We intend to recover our receivable through our legal rights to enforce the parental guarantee, independent of the resolution of the disputed claim. The ultimate resolution of each of these matters is unknown at this time. During 2007, we recorded an impairment of our investments in these projects of approximately $15 million as a result of our assessment of these matters and other unrelated mechanical failures at the plants. Adverse developments related to either our ability to collect amounts due to us or related to the dispute could require us to record additional losses in the future.

Asian and Central American power investments. As of December 31, 2007, our total investment (including advances to the projects) and guarantees related to these projects was approximately $78 million. We are in the process of selling these assets. Any changes in political and economic conditions could negatively impact the amount of net proceeds we expect to receive upon their sale, which may result in additional impairments.

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of December 31, 2007, our total investment and guarantees related to this pipeline project was approximately $117 million, of which the Bolivian portion was $3 million. In 2006, the Bolivian government announced a decree significantly increasing its interest in and control over Bolivia s oil and gas assets. We continue to monitor and evaluate, together with our partners, the potential commercial impact that these political events in Bolivia could have on our investment. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Investment in Argentina. We own an approximate 22 percent interest in the Argentina to Chile pipeline. As of December 31, 2007, our total investment in this pipeline project was approximately $21 million. We are currently evaluating opportunities to sell our interest in this pipeline. In addition, in July 2006, the Ministry of Economy and Production in Argentina issued a decree that significantly increases the export taxes on natural gas. We continue to evaluate, together with our partners, the potential commercial impact that this and other decrees could have on the Argentina to Chile pipeline and the potential value we expect to receive upon the sale of our investment. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

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Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, adjusted to reflect our discontinued operations, is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(In millions, except per common share amounts)				
2007					
Operating revenues	$1,022	$1,198	$ 1,166	$ 1,262	$4,648
Operating income	335	451	417	442	1,645
Earnings (losses) from unconsolidated affiliates	37	44	(6)	26	101
Income (loss) from continuing operations	(48)	169	155	160	436
Discontinued operations, net of income taxes	677	(3)			674
Net income	629	166	155	160	1,110
Net income available to common stockholders	620	156	146	151	1,073
Basic earnings per common share					
Income (loss) from continuing operations	(0.08)	0.23	0.21	0.22	0.57
Net income	0.89	0.23	0.21	0.22	1.54
Diluted earnings per common share					
Income (loss) from continuing operations	(0.08)	0.22	0.20	0.21	0.57
Net income	0.89	0.22	0.20	0.21	1.53
2006					
Operating revenues	$1,337	$1,089	$ 942	$ 913	$4,281
Operating income	683	363	218	163	1,427
Earnings from unconsolidated affiliates	29	37	55	24	145
Income (loss) from continuing operations	301	134	111	(15)	531
Discontinued operations, net of income taxes	55	16	24	(151)	(56)
Net income (loss)	356	150	135	(166)	475
Net income (loss) available to common stockholders	346	141	126	(175)	438
Basic earnings per common share					
Income (loss) from continuing operations	0.44	0.19	0.15	(0.03)	0.73
Net income (loss)	0.53	0.21	0.18	(0.25)	0.65
Diluted earnings per common share					
Income (loss) from continuing operations	0.42	0.19	0.15	(0.03)	0.72
Net income (loss)	0.49	0.21	0.18	(0.25)	0.64

Below are unusual or infrequently occurring items, if any, in each of the respective quarters of 2007 and 2006:

September 30, 2007. Items include (i) $77 million gain in other income related to the reversal of a liability related to a legacy crude oil marketing and trading business matter and (ii) losses of $64 million ($72 million for the year ended December 31, 2007) related to our Porto Velho and Manaus and Rio Negro projects.

June 30, 2007. Items include (i) $86 million loss on debt extinguishment relating to repurchasing notes of El Paso Exploration and Production Company and (ii) a $35 million loss ($100 million for the year ended December 31, 2007) on our PJM power contracts, primarily resulting from increases in installed capacity prices.

March 31, 2007. Items include (i) gain of $651 million, net of taxes of $356 million on the sale of ANR and related assets recorded in discontinued operations and (ii) a loss on extinguishment of debt of $201 million in conjunction with the repurchase of $3.5 billion of debt obligations.

December 31, 2006. Items include (i) $188 million charge associated with the release of capacity under our Alliance contract and (ii) approximately $188 million in deferred taxes related to ANR discontinued operations (Note 2).

September 30, 2006. Items include (i) Mark-to-market losses of $133 million on our MCV supply agreement recorded in conjunction with the sale of our interest in the related power facility and (ii) a $105 million income tax benefit associated with the reduction of tax contingencies and reinstatement of certain tax credits as a result of IRS audit settlements and net tax amounts recognized on certain foreign investments (Note 4).

June 30, 2006. Items include income tax benefit of $34 million associated with IRS audit settlements (Note 4).

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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, in the United States, Brazil and Egypt.

Capitalized Costs. 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 and Egypt(1)	Worldwide
2007			
Natural gas and oil properties:			
Costs subject to amortization	$ 17,631	$ 546	$ 18,177
Costs not subject to amortization	474	265	739
	18,105	811	18,916
Less accumulated depreciation, depletion and amortization	11,847	255	12,102
Net capitalized costs	$ 6,258	$ 556	$ 6,814
2006			
Natural gas and oil properties:			
Costs subject to amortization	$ 15,582	$ 460	$ 16,042
Costs not subject to amortization	333	77	410
	15,915	537	16,452
Less accumulated depreciation, depletion and amortization	11,322	202	11,524
Net capitalized costs	$ 4,593	$ 335	$ 4,928

(1) Capitalized costs for Egypt were $14 million and $4 million as of December 31, 2007 and 2006.

Total Costs Incurred. Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows for the year ended December 31 (in millions):

	United States	Brazil and Egypt(1)	Worldwide
2007			
Property acquisition costs			
Proved properties	$ 964	$	$ 964
Unproved properties	262	5	267
Exploration costs	398	199	597
Development costs	735	26	761

Costs expended	2,359	230	2,589
Asset retirement obligation costs	38	7	45
Total costs incurred	$ 2,397	$ 237	$ 2,634
Unconsolidated investment in Four Star	$ 27	$	$ 27
2006			
Property acquisition costs			
Proved properties	$ 2	$ 2	$ 4
Unproved properties	34	1	35
Exploration costs	323	53	376
Development costs	738	40	778
Costs expended	1,097	96	1,193
Asset retirement obligation costs	3		3
Total costs incurred	$ 1,100	$ 96	$ 1,196
2005			
Property acquisition costs			
Proved properties	$ 643	$ 8	$ 651
Unproved properties	143	1	144
Exploration costs	143	15	158
Development costs	503	6	509
Costs expended	1,432	30	1,462

	United States	Brazil and Egypt[1]	Worldwide
Asset retirement obligation costs	1		1
Total costs incurred	$ 1,433	$ 30	$ 1,463
Unconsolidated investment in Four Star[2]	$ 769	$	$ 769

(1) Costs incurred for Egypt were $10 million and $4 million for the years ended December 31, 2007 and 2006.

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

Pursuant to the full cost method of accounting, we capitalize certain general and administrative expenses related to property acquisition, exploration and development activities and interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. The table above includes capitalized internal general and administrative costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $69 million, $50 million and $47 million for the years ended December 31, 2007, 2006 and 2005. We also capitalized interest of $35 million, $30 million and $30 million for the years ended December 31, 2007, 2006 and 2005.

In our January 1, 2008 reserve report, the amounts estimated to be spent in 2008, 2009 and 2010 to develop our consolidated worldwide proved undeveloped reserves are $743 million, $515 million and $170 million.

Unevaluated Capitalized Costs. We exclude capitalized costs of natural gas and oil properties from amortization that are in various stages of evaluation. We expect a majority of these costs to be included in the amortization calculation in 2008 and 2009.

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, 2007, pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2007	Costs Excluded for Years Ended[1] December 31 2007	2006	2005	Cumulative Balance December 31, 2004
United States					
Acquisition	$ 418	$ 235	$ 30	$ 126	$ 27
Exploration	56	37	14	3	2
Development					
Total United States	474	272	44	129	29
Brazil & Egypt					
Acquisition	8	3	2		3
Exploration	257	193	45	9	10
Development					
Total Brazil & Egypt	265	196	47	9	13
Worldwide	$ 739	$ 468	$ 91	$ 138	$ 42

[1] Includes capitalized interest of $33 million, $24 million and $9 million for the years ended December 31, 2007, 2006 and 2005.

Natural Gas and Oil Reserves. Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil and condensate, and changes in these reserves at December 31, 2007 presented in the tables below are based on our internal reserve report. 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. Our consolidated reserves are 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, an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of 84 percent of our consolidated natural gas and oil reserves. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising greater than 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 75 percent of the proved reserves of Four Star, our unconsolidated affiliate. Our estimates of Four Star s proved natural gas and oil reserves are prepared by our internal reservoir engineers and do not reflect those prepared by the engineers of Four Star. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. Ryder Scott s reports are included as exhibits to this Annual Report on Form 10-K.

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	United States	Brazil	Worldwide	United States	Brazil	Worldwide	United States	
Consolidated								
January 1, 2005	1,724	69	1,793	27,331	24,171	51,502	13,201	2,181
Revisions due to prices	18	4	22	945	210	1,155	115	30
Revisions other than price	(61)	(6)	(67)	(685)	7,717	7,032	1,033	(19)
Extensions and discoveries	183	5	188	8,145	772	8,917	169	242
Purchases of reserves in place	192		192	13,338		13,338	772	276
Sales of reserves in place	(18)		(18)	(969)		(969)	(89)	(24)
Production	(207)	(16)	(223)	(4,877)	(620)	(5,497)	(2,639)	(271)
December 31, 2005	1,831	56	1,887	43,228	32,250	75,478	12,562	2,415
Revisions due to prices	(48)		(48)	(1,007)		(1,007)	(152)	(55)
Revisions other than price	56	(1)	55	(507)	(365)	(872)	(1,682)	40
Extensions and discoveries	254	8	262	5,012	209	5,221	958	299
Purchases of reserves in place	1		1	90		90	32	2
Sales of reserves in place	(17)		(17)	(230)		(230)	(174)	(20)
Production	(213)	(7)	(220)	(5,907)	(247)	(6,154)	(1,532)	(266)
December 31, 2006	1,864	56	1,920	40,679	31,847	72,526	10,012	2,415
Revisions due to prices	28		28	2,336	10	2,346	154	43
Revisions other than price	(39)	(1)	(40)	3,711	1,010	4,721	(35)	(12)
Extensions and discoveries	296		296	5,876		5,876	1,681	341
Purchases of reserves in place	339		339	3,111		3,111		357
Sales of reserves in place	(2)		(2)	(73)		(73)		(2)
Production	(238)	(4)	(242)	(5,966)	(157)	(6,123)	(1,698)	(289)
December 31, 2007	2,248	51	2,299	49,674	32,710	82,384	10,114	2,853
Proved developed reserves								
December 31, 2005	1,404	27	1,431	28,581	1,144	29,725	11,010	1,675
December 31, 2006	1,469	23	1,492	29,616	824	30,440	8,665	1,727
December 31, 2007	1,738	19	1,757	35,070	680	35,750	8,132	2,020
Unconsolidated investment in Four Star								
December 31, 2007								
Net proved developed and undeveloped reserves	200		200	2,858		2,858	6,411	256
Proved developed reserves	170		170	2,804		2,804	5,345	219
December 31, 2006								
	167		167	2,947		2,947	6,209	222

Net proved developed and undeveloped reserves						
Proved developed reserves	139	139	2,874	2,874	5,095	187

In 2007, of the 341 Bcfe of extensions and discoveries, 80 Bcfe related to the Raton area in northern New Mexico, 43 Bcfe related to the McCook area in south Texas, 34 Bcfe related to the Zapata area in south Texas, 26 Bcfe related to the success in the Niobrara and Johnson counties in Wyoming, 22 Bcfe related to the Mustang Island 739/740 block in the Gulf of Mexico and 20 Bcfe related to the Victoria area in south Texas.

In 2006, of the 299 Bcfe of extensions and discoveries, 45 Bcfe related to the coal bed methane projects in central Alabama, 37 Bcfe related to the House Creek Parkman and County Line areas in northeast Wyoming, 35 Bcfe related to the McCook area in South Texas, 27 Bcfe related to the Raton area in northern New Mexico, 18 Bcfe related to the Victoria area in south Texas, 18 Bcfe related to the Bear Creek area in northern Louisiana, and 16 Bcfe related to the Minden area in east Texas.

In 2005, of the 242 Bcfe of extensions and discoveries, 46 Bcfe related to the Holly and Minden fields in northwest Louisiana and east Texas, 39 Bcfe related to the West Cameron 62/75 offshore block in the Gulf of Mexico, 25 Bcfe related to the Raton area in northern New Mexico, 22 Bcfe related to the coal bed methane projects in central Alabama, 22 Bcfe related to the House Creek Parkman area in northeast Wyoming, and 14 Bcfe related to the Altamont/Bluebell area in northeast Utah.

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

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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, 2007.

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

	United States	Brazil	Worldwide
2007			
Net Revenues			
Sales to external customers	$ 1,085	$ 25	$ 1,110
Affiliated sales	1,149	(8)	1,141
Total	2,234	17	2,251
Cost of products and services[1]	(72)		(72)
Production costs[2]	(327)	(11)	(338)
Depreciation, depletion and amortization	(748)	(16)	(764)
	1,087	(10)	1,077
Income tax expense	(392)	4	(388)
Results of operations from producing activities	$ 695	$ (6)	$ 689
Equity earnings from unconsolidated investment in Four Star	$ 12	$	$ 12
Depreciation, depletion and amortization ($/Mcfe)	$ 2.63	$ 3.10	$ 2.64
2006			
Net Revenues			
Sales to external customers	$ 608	$ 41	$ 649
Affiliated sales	1,160	(9)	1,151
Total	1,768	32	1,800
Cost of products and services[1]	(58)		(58)
Production costs[2]	(318)	(7)	(325)
Depreciation, depletion and amortization	(611)	(19)	(630)
	781	6	787
Income tax expense	(281)	(2)	(283)
Results of operations from producing activities	$ 500	$ 4	$ 504
Equity earnings from unconsolidated investment in Four Star	$ 10	$	$ 10
Depreciation, depletion and amortization ($/Mcfe)	$ 2.37	$ 2.14	$ 2.36
2005			
Net Revenues			
Sales to external customers	$ 466	$ 62	$ 528
Affiliated sales	1,268	(9)	1,259

Total	1,734	53	1,787
Cost of products and services[1]	(47)		(47)
Production costs[2]	(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[3]	$ 19	$	$ 19
Depreciation, depletion and amortization ($/Mcfe)	$ 2.25	$ 2.31	$ 2.26

(1) Cost of products and services consists primarily of transportation costs.

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

(3) Acquired in August 2005.

Standardized Measure of Discounted Future Net Cash Flows. 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
2007			
Future cash inflows[1]	$ 19,329	$ 3,226	$ 22,555
Future production costs	(4,822)	(560)	(5,382)
Future development costs	(1,805)	(444)	(2,249)
Future income tax expenses	(3,144)	(625)	(3,769)
Future net cash flows	9,558	1,597	11,155
10% annual discount for estimated timing of cash flows	(3,704)	(617)	(4,321)
Standardized measure of discounted future net cash flows	$ 5,854	$ 980	$ 6,834
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 5,902	$ 980	$ 6,882
2006			
Future cash inflows[1]	$ 12,349	$ 1,977	$ 14,326
Future production costs	(3,623)	(431)	(4,054)
Future development costs	(1,280)	(506)	(1,786)
Future income tax expenses	(1,089)	(239)	(1,328)
Future net cash flows	6,357	801	7,158
10% annual discount for estimated timing of cash flows	(2,302)	(377)	(2,679)
Standardized measure of discounted future net cash flows	$ 4,055	$ 424	$ 4,479
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,225	$ 424	$ 4,649
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						
2007	$	444	$		$	444
2006	$	323	$		$	323
2005	$	617	$		$	617

(1) United States excludes $61 million, $219 million and $(502) million of future net cash inflows (outflows) attributable to hedging activities in the years 2007, 2006 and 2005. Brazil excludes $4 million of future net cash outflows attributable to hedging activities in 2005.

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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 $6.80, $5.64, and $10.08 per MMBtu for natural gas and $95.98, $61.05 and $61.04 per barrel of oil at December 31, 2007, 2006 and 2005. In the United States, after adjustments for transportation and other charges, net prices were $6.40 per Mcf of gas, $87.88 per barrel of oil and $58.63 per barrel of NGL at December 31, 2007. 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.

Changes in Standardized Measure of Discounted Future Net Cash Flows. 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]		
	2007	2006	2005
		(In millions)	
Sales and transfers of natural gas and oil produced net of production costs	$ (1,657)	$ (1,516)	$ (1,477)
Net changes in prices and production costs	2,723	(2,891)	2,884
Extensions, discoveries and improved recovery, less related costs	910	549	793
Changes in estimated future development costs	(4)	(55)	2
Previously estimated development costs incurred during the period	200	192	247
Revision of previous quantity estimates	117	(38)	47
Accretion of discount	501	827	476
Net change in income taxes	(1,333)	1,123	(1,093)
Purchases of reserves in place	810	4	956
Sale of reserves in place	(7)	(42)	(83)
Change in production rates, timing and other	95	(289)	(333)
Net change	$ 2,355	$ (2,136)	$ 2,419

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

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SCHEDULE II
EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2007, 2006 and 2005
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2007					
Allowance for doubtful accounts	$ 28	$ (4)	$ (5)	$ (2)	$ 17
Valuation allowance on deferred tax assets	127	10			137
Legal reserves[7]	548	36	(128)[2]	4	460
Environmental reserves	314	21	(75)		260
Regulatory reserves[3]	65	61	(116)		10
2006[1]					
Allowance for doubtful accounts	$ 65	$ (5)	$ (27)[4]	$ (5)	$ 28
Valuation allowance on deferred tax assets	107	23		(3)	127
Legal reserves[7]	574	48	(74)		548
Environmental reserves	348	30	(64)		314
Regulatory reserves[3]	1	65	(1)		65
2005[1]					
Allowance for doubtful accounts	$ 195	$ (68)	$ (54)[4]	$ (8)	$ 65
Valuation allowance on deferred tax assets	51	34[5]		22	107
Legal reserves[7]	592	496	(516)[6]	2	574
Environmental reserves	349	60	(61)[6]		348
Regulatory reserves	1				1

(1) Amounts reflect the reclassification of discontinued operations.

(2) Included is the settlement of our shareholder litigation lawsuits.

(3) In 2006 and 2007, we recorded reserves for rate refunds under

EPNG s rate case which was settled in 2007 and refunds paid to customers.

(4) In 2006, relates primarily to the sale of our accounts receivable under an accounts receivable sales program. In 2005, relates primarily to accounts written off.

(5) 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.

(6) Relates primarily to payments for various litigation reserves (including $442 million related to the Western Energy Settlement), environmental remediation reserves or revenue

crediting and rate settlement reserves.

(7) Amounts are net of related insurance receivables.

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, 2007, 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 U.S. Securities and Exchange Commission (SEC) reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based on the results of this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective at a reasonable level of assurance at December 31, 2007. 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 of 2007.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information included under the captions Corporate Governance , Proposal No. 1 Election of Directors , Section 16(a), Beneficial Ownership Reporting Compliance and Information about the Board of Directors and Committees in our Proxy Statement for the 2008 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 required by the New York Stock Exchange corporate governance listing standards, in June 2007, Douglas L. Foshee, our president and chief executive officer, submitted an unqualified certification to the New York Stock Exchange that as of the date of the certification, he was not aware of any violation by El Paso of the exchange s corporate governance standards. The certifications of our chief executive officer and chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are attached as Exhibits 31.A and 31.B to this report.

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the captions Information about the Board of Directors and Committees Compensation Committee Interlocks and Insider Participation , Executive Compensation , Director Compensation and Compensation Committee Report in our Proxy Statement for the 2008 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 captions Security Ownership of Certain Beneficial Owners and Management and Equity Compensation Plan Information Table in our Proxy Statement for the 2008 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information appearing under the captions Corporate Governance Independence of Board Members and Corporate Governance Transactions with Related Persons in our Proxy Statement for the 2008 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information appearing under the caption Proposal No. 2 Ratification of Appointment of Ernst & Young, LLP as our Independent Registered Public Accountant Principal Accountant Fees and Services and Information about the Board of Directors Policy for Approval of Audit and Non-Audit Fees, in our Proxy Statement for the 2008 Annual Meeting of Stockholders is incorporated herein by reference.

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

3. Exhibits

The Exhibit Index, which index follows the signature page to this report and is hereby incorporated herein by reference, sets forth a list of those exhibits filed herewith, and includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 (b)(10)(iii) of Regulation S-K.

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.

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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 28th day of February, 2008.

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)	February 28, 2008
/s/ D. Mark Leland D. Mark Leland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ John R. Sult John R. Sult	Senior Vice President and Controller (Principal Accounting Officer)	February 28, 2008
/s/ Ronald L. Kuehn, Jr. Ronald L. Kuehn, Jr.	Chairman of the Board	February 28, 2008
/s/ Juan Carlos Braniff Juan Carlos Braniff	Director	February 28, 2008
/s/ James L. Dunlap James L. Dunlap	Director	February 28, 2008
/s/ Robert W. Goldman Robert W. Goldman	Director	February 28, 2008
/s/ Anthony W. Hall, Jr. Anthony W. Hall, Jr.	Director	February 28, 2008
/s/ Thomas R. Hix	Director	February 28, 2008

Thomas R. Hix		
/s/ William H. Joyce	Director	February 28, 2008
William H. Joyce		
/s/ Ferrell P. McClean	Director	February 28, 2008
Ferrell P. McClean		
/s/ Steven J. Shapiro	Director	February 28, 2008
Steven J. Shapiro		
/s/ J. Michael Talbert	Director	February 28, 2008
J. Michael Talbert		
/s/ Robert F. Vagt	Director	February 28, 2008
Robert F. Vagt		
/s/ John L. Whitmire	Director	February 28, 2008
John L. Whitmire		
/s/ Joe B. Wyatt	Director	February 28, 2008
Joe B. Wyatt		

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EL PASO CORPORATION
EXHIBIT INDEX
December 31, 2007

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.

Exhibit Number	Description
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 December 6, 2007 (Exhibit 3.B to our Form 8-K filed December 6, 2007).
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	Tenth Supplemental Indenture dated as of December 28, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Form 8-K filed January 4, 2006).
4.E	Eleventh Supplemental Indenture dated as of August 31, 2006, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our 2006 Third Quarter Form 10-Q).
4.F	Twelfth Supplemental Indenture dated as of June 18, 2007 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our 2007 Second Quarter Form 10-Q).
+10.A	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.A.1	Amendment No. 1 effective as of January 1, 2007 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003.
+10.B	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).
+10.B.1	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).
*+10.B.2	Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors.

+10.B.3	Amendment No. 3 effective as of October 26, 2006 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.N to our 2006 Third Quarter Form 10-Q).
+10.C	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);
*+10.C.1	Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors.
*+10.C.2	Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors.
+10.C.3	Amendment No. 3 effective as of October 26, 2006 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.O to our 2006 Third Quarter Form 10-Q).
+10.D	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 Number	Description
	(Exhibit 10.I.2 to our 2004 Form 10-K); Amendment No. 3 effective as of October 26, 2006 to the 1995 Omnibus Compensation Plan (Exhibit 10.L to our 2006 Third Quarter Form 10-Q).
*+10.E	1999 Omnibus Incentive Compensation Plan dated January 20, 1999.
*+10.E.1	Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan.
+10.E.2	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.E.3	Amendment No. 3 effective as of October 26, 2006 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.K to our 2006 Third Quarter Form 10-Q).
*+10.F	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001.
*+10.F.1	Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan.
*+10.F.2	Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan.
*+10.F.3	Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan.
+10.F.4	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).
+10.F.5	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.F.6	Amendment No. 6 effective as of October 26, 2006 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.M to our 2006 Third Quarter Form 10-Q).
*+10.G	Supplemental Benefits Plan Amended and Restated effective December 7, 2001.
*+10.G.1	Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan.
+10.G.2	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.G.3	Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q).
+10.G.4	Amendment No. 4 to the Supplemental Benefits Plan effective as of December 31, 2004 (Exhibit 10.I.1 to our 2005 Form 10-K).
*+10.G.5	Amendment No. 5 effective as of January 1, 2007 to the Supplemental Benefits Plan Amended and Restated effective December 7, 2001.

+10.H	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 2004 Form 10-K).
*+10.H.1	Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan.
*+10.H.2	Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan.
+10.I	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.N to our 2004 Form 10-K).
*+10.I.1	Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan.
*+10.I.2	Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan.
*+10.I.3	Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan.
+10.I.4	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.I.5	Amendment No. 5 effective as of January 1, 2007 to the Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998.
+10.J	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K).
*+10.J.1	Amendment No. 1 effective as of January 1, 2007 to the 2004 Key Executive Severance Protection Plan effective as of March 9, 2004.

Exhibit Number	Description
+10.K	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 2004 Form 10-K).
*+10.K.1	Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan.
+10.K.2	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.L	Strategic Stock Plan Amended and Restated effective as of December 3, 1999.
*+10.L.1	Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan.
*+10.L.2	Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan.
*+10.L.3	Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan.
*+10.L.4	Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan.
+10.L.5	Amendment No. 5 effective as of October 26, 2006 to the Strategic Stock Plan (Exhibit 10.J to our 2006 Third Quarter Form 10-Q).
+10.M	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.R to our 2004 Form 10-K).
+10.N	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).
*+10.N.1	Termination of the Executive Award Plan of Sonat Inc.
+10.N.2	Amendment to the Executive Award Plan of Sonat Inc. effective as of October 26, 2006 (Exhibit 10.H to our 2006 Third Quarter Form 10-Q).
*+10.O	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999.
*+10.O.1	Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees.
*+10.O.2	Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees.
*+10.O.3	Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management.
*+10.O.4	Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees.
+10.O.5	Amendment No. 5 effective as of October 26, 2006 to the Corporation Omnibus Plan for Management Employees (Exhibit 10.I to our 2006 Third Quarter Form 10-Q).
+10.P	Severance Pay Plan Amended and Restated effective as of October 1, 2002 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003

	(Exhibit 10.Z to our 2003 First Quarter Form 10-Q); 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); Supplement No. 2 dated April 1, 2005 to the Severance Pay Plan Amended and Restated effective as of October 1, 2002 (Exhibit 10.S.1 to our 2005 Form 10-K).
*+10.P.1	Amendment No. 1 effective January 1, 2007 to the Severance Pay Plan Amended and Restated effective as of October 1, 2002.
+10.Q	Letter Agreement dated September 20, 2006 between El Paso Corporation and Brent J. Smolik (Exhibit 10.A to our Form 8-K filed October 16, 2006).
+10.R	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.S	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K).
+10.T	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).

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Exhibit Number	Description
+10.U	Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto (Exhibit 10.F to our 2006 Third Quarter Form 10-Q).
+10.V	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2004 Third Quarter Form 10-Q).
10.W	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.X	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.Y	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.A to our Form 8-K filed May 31, 2005); Amendment No. 1 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of October 26, 2006 (Exhibit 10.P to our 2006 Third Quarter Form 10-Q).
*+10.Y.1	Amendment No. 2 effective as of January 1, 2007 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005.
+10.Z	El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of May 26, 2005 (Exhibit 10.B to our Form 8-K filed May 31, 2005); Amendment No. 1 to the 2005 Omnibus Incentive Compensation Plan effective as of December 2, 2005 (Exhibit 10.HH.1 to our 2005 Form 10-K); Amendment No. 2 to the El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of October 26, 2006 (Exhibit 10.Q to our 2006 Third Quarter Form 10-Q).
*+10.Z.1	Amendment No. 3 to the El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of May 26, 2005.
+10.AA	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); Amendment No. 1 to the El Paso Corporation Employee Stock Purchase Plan effective as of October 26, 2006 (Exhibit 10.G to our 2006 Third Quarter Form 10-Q).
+10.BB	2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.KK to our 2005 Form 10-K).
*+10.BB.1	Amendment No. 1 effective as of January 1, 2007 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005.
10.CC	Credit Agreement dated as of July 19, 2006 among El Paso Corporation, as Borrower, Deutsche Bank AG New York Branch, as Initial Lender, Issuing Bank, Administrative Agent and Collateral Agent (Exhibit 10.A to our Form 8-K filed July 20, 2006).

10.DD	Third Amended and Restated Credit Agreement dated as of November 16, 2007, among El Paso Corporation, 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 21, 2007).
10.EE	Third Amended and Restated Security Agreement dated as of November 16, 2007, made by among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors 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 21, 2007).
10.FF	Third Amended and Restated Subsidiary Guarantee Agreement dated as of November 16, 2007, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.C to our Form 8-K filed November 21, 2007).
10.GG	Purchase and Sale Agreement dated December 22, 2006, among El Paso Corporation, El Paso CNG Company, L.L.C., and TransCanada American Investments Ltd. (Exhibit 10.A to our Form 8-K filed December 29, 2006).
10.HH	Purchase and Sale Agreement dated December 22, 2006, among El Paso Great Lakes Company, L.L.C., TC GL Intermediate Limited Partnership and TransCanada PipeLine USA Ltd. (Exhibit 10. B to our Form 8-K filed December 29, 2006).
*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, Ernst & Young LLP.

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Exhibit Number	Description
*23.B	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers, LLP.
*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
*99.A	Ryder Scott reserve report for El Paso Exploration & Production Company as of December 31, 2007.
*99.B	Ryder Scott reserve report for Four Star Oil & Gas Company as of December 31, 2007.