EL PASO CORP/DE
Form 10-K
March 01, 2010

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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, 2009

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 o No þ.

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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. þ

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	Smaller reporting company o
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 30, 2009, the last business day of the registrant s most recently completed second fiscal quarter, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date: $6,471,986,386.

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 23, 2010: 701,318,796

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 2010 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2010.

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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
KM	=	kilometer
LNG	=	liquefied natural gas
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
Mcfe	=	thousand cubic feet of natural gas equivalents
MDth	=	thousand decatherms
MMBtu	=	million British thermal units
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
GWh	=	thousand megawatt hours
GW	=	gigawatts
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.

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 933 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 developing growth projects in our market and supply areas.

Exploration and Production. Our exploration and production business focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States (U.S.), Brazil and Egypt. During 2009, in the U.S., we shifted our focus to more unconventional resources including the Haynesville Shale in northwest Louisiana and east Texas, Eagle Ford Shale in south Texas, and Altamont-Bluebell-Cedar Rim Field fractured tight sands in Utah. As of December 31, 2009, we held estimated proved natural gas and oil reserves of 2.75 Tcfe, including 0.2 Tcfe of proved natural gas and oil reserves related to Four Star Oil & Gas Company (Four Star), our unconsolidated affiliate. Our focus is on growing our reserve base over the long-term 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 17. In October 2009, we also announced our re-entry into the midstream business where we believe that the movement to more unconventional supply basins will present future opportunities.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through seven separate, wholly or majority owned pipeline systems, and four 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, three underground natural gas storage facilities, and two LNG terminalling facilities one of which is under construction.

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

- providing outstanding customer service;
- executing successfully on time and on budget our backlog of committed expansion projects;
- developing new growth projects in our market and supply areas;
- ensuring the safety of our pipeline systems and assets;
- optimizing our contract portfolio; and

focusing on efficiency and synergies across our systems.

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Natural gas pipeline systems. The tables below provide more information on our pipeline systems:

		As of December 31, 2009						
Transmission System	**Supply and Market Region**	**Ownership Percentage (Percent)**	**Miles of Pipeline**	**Design Capacity (MMcf/d)**	**Storage Capacity (Bcf)**	**Average Throughput(1)**		
						2009	**2008 (BBtu/d)**	**2007**
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	7,208	92(2)	4,614	4,864	4,880
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian, Anadarko basins and via interconnections in 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(3)	44	3,937	4,379	4,189
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.	100	500	400(4)		379	349	458
Cheyenne Plains Gas Pipeline (CPG)(5)	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	934		841	898	735

(1) Includes throughput transported on behalf of affiliates.

(2) Includes 29 Bcf of storage capacity from Bear Creek Storage Company, L.L.C (Bear Creek) which TGP owns equally with Southern Natural Gas Company.

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

(4) Reflects east to west flow capacity.

(5) We own 100 percent of the common shares. See Part II, Item 8, Financial Statements and Supplementary Data, Note 18.

		As of December 31, 2009						
Transmission System	Supply and Market Region	Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2009	2008 (BBtu/d)	2007
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.	92	7,600	3,700	60[2]	2,322	2,339	2,345
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.	81	4,200	3,750	35[3]	2,299	2,225	2,339
Wyoming Interstate (WIC)	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	67	800	3,340		2,652	2,543	2,071
Florida Gas Transmission (FGT)[4]	Extends from South Texas to South Florida.	50	5,000	2,100		2,250	2,147	2,056

Samalayuca Pipeline and Gloria a Dios Compression Station(5)	Extends from U.S.-Mexico border into the state of Chihuahua, Mexico.	50	23	460	439	428	462
San Fernando Pipeline(5)	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 29 Bcf of storage capacity from Bear Creek which SNG owns equally with TGP.

(3) Includes 6 Bcf of storage capacity from Totem Gas Storage which is owned by WYCO Development L.L.C. (WYCO), our 50 percent equity investee.

(4) We have a 50 percent equity interest in Citrus Corp. (Citrus), which

owns this system.

(5) We have a 50 percent equity interest in Gasoductos de Chihuahua, which owns these systems. In February 2010, we entered into an agreement to sell our interest in these assets.

Liquefied Petroleum Gas (LPG) Pipeline System. In December 2007, we placed the LPG Burgos pipeline in service. This 117 mile pipeline, in which we own a 50 percent interest, transports liquefied petroleum gas and extends from Pemex s Burgos complex to the Monterrey market in the state of Nuevo León, Mexico. The system has a design capacity of 34,000 barrels/day and transported an average of 30,000 barrels/day in 2009, 2008 and 2007.

WYCO. We own a 50 percent interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). WYCO owns Totem Gas Storage and the High Plains pipeline, which were placed in service in June 2009 and November 2008, respectively, and are operated by us. The High Plains pipeline consists of a 164-mile interstate gas pipeline extending from the Cheyenne Hub in northeast Colorado to PSCo s Fort St. Vrain electric generation plant and other points of interconnections with PSCo s system. The Totem Gas Storage facility interconnects with the High Plains Pipeline and has 6 Bcf of working natural gas storage capacity, with a maximum withdrawal rate of 200 MMcf/d and a maximum injection rate of 100 MMcf/d. WYCO also owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to PSCo s Fort St. Vrain s electric generation plant, which we do not operate, and a compressor station in Wyoming that we operate.

Underground Natural Gas Storage Facilities. In addition to the storage capacity in our wholly and majority owned pipeline systems, we have interests in the following natural gas storage facilities:

	As of December 31, 2009		
Storage Facility	**Ownership Interest (Percent)**	**Storage Capacity (Bcf)**	**Location**
Bear Creek	100	58(1)	Louisiana
Young Gas Storage	48	6(2)	Colorado

(1) Approximately 58 Bcf is contracted to affiliates.

(2) Amount is not adjusted for our ownership interest.

Master Limited Partnership. At December 31, 2009, our master limited partnership, EPB, owns WIC, a 58 percent general partner interest in CIG and a 25 percent general partner interest in SNG. As of December 31, 2009, we had a two percent general partner interest and a 65 percent limited partner interest in EPB. Subsequent to a January 2010 public common unit offering, we now own a two percent general partner interest and a 60 percent limited partner interest in EPB.

Federal Energy Regulatory Commission (FERC) Approved Projects. As of December 31, 2009, we had the following significant FERC approved expansion projects on our systems. For a further discussion of other expansion projects, see Part II, 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**
South System III	SNG	370	To add 81 miles of pipe and 17,310 of horsepower compression on our pipeline facilities	2011 2012
	SNG	350		2011

Southeast Supply Header Phase II			To add 26,000 of horsepower compression to the jointly owned pipeline facilities	
FGT Phase VIII	FGT[1]	800	To add more than 483 miles of pipeline loops, laterals and mainline and 213,600 of horsepower compression	2011

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

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LNG Facilities

Elba Island LNG. 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 0.9 Bcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

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.

Gulf LNG. 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 LNG terminal in Pascagoula, Mississippi with a designed sendout capacity of 1.5 bcf/d that is expected to be placed in service in October 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, solar and fuel oil.

The gas industry is undergoing a major shift in supply sources. Production from conventional sources is declining while production from unconventional sources, such as shale, tight sands, and coal bed methane, is rapidly increasing. This shift will change the supply patterns and flows on pipelines. The impact will vary among pipelines according to the proximity of the new supply sources. One of our pipelines is connected to two major shale formations: the Haynesville in northern Louisiana and Texas and the Marcellus in Pennsylvania. It is likely that gas from these sources will, over time, displace receipts from traditional sources in south Texas and the Gulf of Mexico on our system. In addition, our system is close to the Eagle Ford Shale formation in south Texas, which could be a major source of supply into the system in the future. This will affect the flows on the system and the array of shipper contracts.

Another change in the supply patterns is the reduction in imports from Canada. This decrease has been the result of declining production and increasing demand in Canada. This reduction has led to increased demand for domestic supplies and related transportation services, but it has been offset in part by imported LNG. LNG has become a significant supply source for the North American market. LNG terminals and other regasification facilities can serve as alternate 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 has been a growing demand sector of the natural gas market. The growth of natural gas-fired electric power benefits the natural gas industry by creating more demand for natural gas. 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.

Growth of the natural gas market has been adversely affected by the current economic slowdown in the U.S. and global economies. The decline in economic activity reduced industrial demand for natural gas and electricity, which affected natural gas demand both directly in end-use markets and indirectly through lower power generation demand for natural gas. We expect the demand and growth for natural gas to return as the economy recovers. Natural gas has a favorable competitive position as an electric generation fuel because it is a clean, abundant fuel with lower capital requirements compared with other alternatives. The lower demand and the credit restrictions on investments in the recent past may slow development of supply projects. As a result, our pipelines may experience lower throughput, lower revenues and slower development of new expansion projects. While our pipeline systems could experience some level of reduced throughput and revenues, or slower development of expansion projects as a result of these factors, each generates a significant portion of its revenues through monthly reservation or demand charges on long-term contracts at rates stipulated under our tariffs or in our contracts.

Our existing transportation and storage contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our 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 maximum rates allowed under our tariffs, although at times, we enter into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems. The weighted average remaining contract term for active contracts is approximately five years. The table below shows the years of expiration of our firm transportation contracts as of December 31, 2009 for our wholly and majority owned systems.

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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, 2009. 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 transport, store, inject or withdraw.

Customer Information	Contract Information	Competition
TGP		
Approximately 470 firm and interruptible customers.	Approximately 510 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in all of its 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 (766 BBtu/d)	Expire in 2011-2029.	
EPNG		
Approximately 160 firm and interruptible customers.	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately three 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, EPNG faces competition from LNG facilities located in northern Mexico.
Major Customers: Sempra Energy and Subsidiaries including Southern California Gas Company (SoCal)		
(374 BBtu/d)	Expires in 2010.	
(334 BBtu/d)	Expires in 2011.	
(12 BBtu/d)	Expires in 2014.	
ConocoPhillips Company		

(350 BBtu/d)	Expires in 2010.
(35 BBtu/d)	Expires in 2011.
(392 BBtu/d)	Expires in 2012.
Southwest Gas Corporation	
(412 BBtu/d)	Expires in 2011.
(75 BBtu/d)	Expires in 2015.

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Customer Information	Contract Information	Competition
MPC Approximately 10 firm and interruptible customers.	Approximately three firm transportation contracts. Weighted average remaining contract term of approximately six years.	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, Mojave faces competition from LNG facilities located in northern Mexico.
Major Customer: EPNG (312 BBtu/d)	Expires in 2015.	
CPG Approximately 40 firm and interruptible customers.	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately seven 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.	
Shell Energy North America US, L.P. (125 BBtu/d)	Expires in 2019.	

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Customer Information	Contract Information	Competition
SNG Approximately 270 firm and interruptible customers.	Approximately 200 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[1] (1,063 BBtu/d)	Expire in 2013-2024.	
Southern Company Services (433 BBtu/d)	Expire in 2011-2018.	
Alabama Gas Corporation (372 BBtu/d)	Expire in 2010-2013.	
SCANA Corporation (315 BBtu/d)	Expire in 2013-2019.	

(1) Atlanta Gas Light Company is currently releasing a significant portion of its firm capacity to a subsidiary of SCANA Corporation under terms allowed by SNG s tariff.

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Customer Information	Contract Information	Competition
CIG		
Approximately 100 firm and interruptible customers.	Approximately 170 firm transportation contracts. Weighted average remaining contract term of approximately eight 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 in 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 (1,787 BBtu/d)	Expire in 2010-2029.	
Williams Gas Marketing, Inc. (498 BBtu/d)	Expire in 2010-2014.	
Anadarko Petroleum Corporation (280 BBtu/d)	Expire in 2011-2015.	

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Customer Information	Contract Information	Competition
WIC		
Approximately 50 firm and interruptible customers	Approximately 60 firm transportation contracts. Weighted average remaining contract term of approximately eight 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. WIC 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:		
Williams Gas Marketing, Inc. (1,320 BBtu/d)	Expire in 2010-2021.	
Anadarko Petroleum Corporation (1,260 BBtu/d)	Expire in 2010-2023.	

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. The FERC approves 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. The FERC s authority also 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 safety and environmental statutes and regulations of the U.S. Department of Transportation and the U.S. Department of the Interior. 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.

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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 U.S., Brazil and Egypt. During 2009, in the U.S., we shifted our focus to more unconventional resources including the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas, and the Altamont-Bluebell-Cedar Rim Field fractured tight sands in Utah. As of December 31, 2009, we controlled approximately 3.9 million net leasehold acres and had proved natural gas and oil reserves of approximately 2.75 Tcfe, including 0.2 Tcfe of proved natural gas and oil reserves related to Four Star, our unconsolidated affiliate. During 2009, daily equivalent natural gas production averaged approximately 763 MMcfe/d, including 72 MMcfe/d from our equity interest in Four Star. We have a balanced portfolio of development and exploration projects that include both long-lived and shorter-lived properties.

Over the past five years, we have grown our exploration and production business through a combination of acquisitions and organic growth initiatives. During this time, we have also sold non-core properties in each of our U.S. divisions in an effort to high grade our asset portfolio. The combination of all these transactions has increased the onshore U.S. weighting of our existing inventory. Our acquisitions include Medicine Bow, which had operations in the western U.S. along with an equity interest in Four Star; Peoples Energy Production Company (Peoples), with operations in east and south Texas, north Louisiana and Mississippi; and producing properties and undeveloped acreage in Zapata County, Texas. Supplementing these acquisitions were smaller bolt-on acquisitions of incremental interests where we already had existing operations, including our acquisition in December 2009 of producing properties located primarily in the Altamont-Bluebell-Cedar Rim Field in Utah. Our organic growth has mainly focused on expanding acreage and inventory in proximity to our existing core assets principally in unconventional areas. We currently operate through three divisions in the U.S. which include Central, Western and Gulf Coast and one internationally. Each division is discussed below.

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U.S.

Central. The Central division includes operations that are primarily focused on shale gas, 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 division. During 2009, we invested $376 million on capital projects and production averaged 257 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2009 Capital Investment (In millions)	Average Production (MMcfe/d)
East Texas/North Louisiana (Arklatex)	Concentrated land positions primarily focused on shale gas and tight gas sands production in the Haynesville Shale, Travis Peak/Hosston, Bossier and Cotton Valley formations. Our operations are primarily in the Bear Creek, Holly, Minden, Bald Prairie, Bethany Longstreet and Logansport fields. We have production and development activities in several fields and hold approximately 40,000 net acres in the Haynesville Shale. We also have land positions in Mississippi. In 2009, we sold certain natural gas producing properties in the Arklatex area.	138,000	$ 329	173
Black Warrior Basin	Established shallow coal bed methane producing areas of northwestern Alabama. We have high average working interests and are actively developing our operated properties in this area. In addition, we have a 50 percent average working interest covering approximately 46,000 net acres operated by Black Warrior Methane Corporation which produces from the Brookwood Field.	110,000	$ 37	58
Mid-Continent	Primarily in Oklahoma with established production in the Arkoma Basin where we utilize horizontal drilling in the Hartshorne Coals for coal bed methane production. We have approximately 207,000 net acres in the Illinois Basin, focused on the development of the New Albany Shale in southwestern Indiana. We are the operator of these properties and have a 95 percent working interest in this area which is producing and still under evaluation for further investment.	411,000	$ 10	26

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Western. The Western division includes operations that are primarily focused on natural gas and oil production from coal bed methane, shale gas and lower risk conventional producing areas. We have a large inventory of drilling prospects in this division. During 2009, we invested $190 million on capital projects, including a producing property acquisition of $87 million, and production averaged 154 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2009 Capital Investment (In millions)	Average Production (MMcfe/d)
Raton Basin	Primarily focused on coal bed methane production in the Raton Basin of northern New Mexico and southern Colorado where we own the minerals beneath the Vermejo Park Ranch.	605,000	$ 17	76
Uintah Basin	Primarily focused on fractured oil production in the Altamont-Bluebell-Cedar Rim Field in Utah. In December 2009, we acquired producing properties located primarily in the Altamont-Bluebell-Cedar Rim Field. We also own and operate the Altamont and Bluebell processing plants and related gathering systems in Utah. In January 2010, we decided to close the Bluebell processing plant in the second quarter of 2010.	203,000	$ 91	42
Rocky Mountains (Rockies)	Primarily in Wyoming with a focus in the Powder River basin, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with a non-operated working interest in the County Line coal bed methane unit.	273,000	$ 82	36

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Gulf Coast. In May 2009, we reorganized our domestic exploration and production operations to combine our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions into the Gulf Coast division. Along the Texas Gulf Coast, we focus on developing and exploring for tight gas sands and unconventional shales in south Texas and the upper Gulf Coast that are characterized by lower risk, longer life production profiles. Our Gulf of Mexico and south Louisiana operations are focused on deeper conventional reservoirs that are characterized by relatively high initial production rates, resulting in higher near-term cash flows and high decline rates. In these areas, we have licensed over 13,500 square miles of three dimensional (3D) seismic data onshore and over 62,500 square miles of 3D seismic data offshore. During 2009, we invested $290 million on capital projects and production averaged 268 MMcfe/d in the Gulf Coast division. The principal operating areas are listed below:

Area	Description	Net Acres	2009 Capital Investment (In millions)	Average Production (MMcfe/d)
South Texas	Includes the Vicksburg/Frio area with concentrated and contiguous assets in the Jeffress and Monte Christo fields primarily in Hidalgo county, in which we have an average 90 percent working interest. This area also includes assets in the Alvarado and Kelsey fields in Starr and Brooks counties with an average working interest of over 83 percent. The Wilcox area includes working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. Other interests in Zapata County include the Bustamante and Las Comitas fields.	78,000	$ 91	142
Upper Texas Gulf Coast	Includes Wilcox assets in the Renger, Dry Hollow, Brushy Creek and Speaks fields located in Lavaca county and Graceland Field located in Colorado county. In 2009, we expanded our lease position in the Eagle Ford Shale, located in Webb and LaSalle counties, to approximately 132,000 net acres as of December 31, 2009. This area also includes Vermilion Parish and associated bays and inland waters in southwestern Louisiana that are covered by the Catapult 3D seismic project. We have internally processed 2,800 square miles of contiguous 3D seismic data in this project.	215,000	$ 122	40
Gulf of Mexico	Gulf of Mexico area includes interests in 70 Blocks south of the Louisiana, Texas and Alabama shoreline focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 400 feet).	262,000	$ 77	86

Unconsolidated Affiliate Four Star. We have an approximate 49 percent equity interest in Four Star. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama basins and in the Gulf of Mexico. During 2009, our equity interest in Four Star s daily equivalent natural gas production averaged approximately 72 MMcfe/d.

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International

Brazil. Our Brazilian operations cover approximately 139,000 net acres in three blocks and nine development areas in the Camamu, Espirito Santo and Potiguar basins located offshore Brazil. During 2009, we invested $155 million on capital projects in Brazil and production averaged 12 MMcfe/d. Our operations in each basin are described below:

Camamu Basin. We own a 100 percent working interest in two development areas, the Camarao and Pinauna Fields. In Pinauna, we are continuing the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development. The timing of the Pinauna Field development will be dependent on the receipt of all required regulatory approvals.

In 2009, we relinquished our interest in the BM-CAL-5 block, operated by Petrobras, but retained an 18 percent working interest in a development area around an exploratory well drilled on the block in 2008. We continue to search for viable commercial options to develop the resources found by the exploratory well. In addition, we continue to own a 20 percent interest in two additional blocks in the Camamu Basin, CAL-M-312 and CAL-M-372, which are located east of and contiguous to the BM-CAL-5 block. We will be further evaluating these two blocks over the next several years. In 2009, we also relinquished our interest in the BM-CAL-6 block following unsuccessful exploration activities in 2008 and the completion of our evaluation of the block.

Espirito Santo Basin. We own an approximate 24 percent working interest in the Camarupim Field. The plan of development for the field included drilling four horizontal natural gas wells, all of which had been drilled and tested as of December 31, 2009. We began natural gas and condensate production in October 2009 from the first well. The second well began production in January 2010, while the third well began production in February 2010. We continue to work with Petrobras to connect the fourth well and anticipate bringing the well on production by the end of 2010.

In 2009, we completed drilling an exploratory well with Petrobras in the ES-5 block in the Espirito Santo Basin in which we own a 35 percent working interest. Hydrocarbons were found in the well and we are now evaluating the results. The exploratory well is located north of the Camarupim Field. In 2010, we plan to participate with Petrobras in spudding another exploratory well in the ES-5 block to evaluate an additional prospect.

Potiguar Basin. We own a 35 percent working interest in the Pescada-Arabaiana Fields. Our production from these fields averaged approximately 9 MMcfe/d in 2009. In late 2009, we executed an agreement with Petrobras to relinquish our interest in two blocks, BM-POT-11 and BM-POT-13.

Egypt. As of December 31, 2009, our Egyptian operations cover approximately 1.4 million net acres in four blocks located primarily onshore in Egypt s Western Desert. During 2009, we invested $81 million on capital projects in Egypt. In 2009, we completed a transaction to swap a 40 percent working interest in our South Mariut block, which contains approximately 700,000 net acres, for an equal working interest in the Tanta block, which contains approximately 300,000 net acres and is located in the Nile Delta area just to the east of and adjacent to our South Mariut block. We also acquired a 50 percent interest in the South Alamein block, which contains approximately 400,000 net acres and is located just south of our South Mariut block. Finally, we own a 22 percent non-operated working interest in the South Feiran concession, which contains approximately 10,000 net acres and is located offshore in the Gulf of Suez. In December 2009, we made a decision to no longer evaluate prospects in the South Feiran concession and are planning to relinquish the concession in March 2010.

In 2009, we drilled or participated in drilling five wells, two in the South Mariut block and three in the South Alamein block. The South Mariut wells and one of the South Alamein wells were unsuccessful, but the other two South Alamein wells discovered hydrocarbons. In late 2009, we spud a fourth exploratory well in the South Alamein block.

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Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents information about our estimated proved reserves included in our internal reserve report as of December 31, 2009, based on 12-month average fiscal-year prices, calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The risks and uncertainties associated with estimating proved natural gas and oil reserves are discussed further in Item 1A, Risk Factors. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2009.

	Net Proved Reserves					2009
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	Total (Percent)	Production (MMcfe)
Reserves and Production by Division						
Consolidated:						
Proved						
U.S.						
Central	1,009,030	1,167		1,016,031	40%	93,785
Western	652,349	52,822		969,281	38%	56,341
Gulf Coast	390,145	6,860	304	433,124	17%	97,880
Total	2,051,524	60,849	304	2,418,436	95%	248,006
Brazil	105,053	4,196		130,232	5%	4,426
Total Consolidated	2,156,577	65,045	304	2,548,668	100%	252,432
Unconsolidated Affiliate[(1)]	158,023	1,907	5,264	201,049	100%	26,142
Total Combined	2,314,600	66,952	5,568	2,749,717	100%	278,574
Reserves by Classification						
Consolidated:						
Proved Developed						
U.S.	1,441,620	26,588	304	1,602,966	63%	
Brazil	90,715	3,212		109,990	4%	
Total	1,532,335	29,800	304	1,712,956	67%	
Proved Undeveloped						
U.S.	609,904	34,261		815,470	32%	
Brazil	14,338	984		20,242	1%	
Total	624,242	35,245		835,712	33%	

Total Consolidated	2,156,577	65,045	304	2,548,668(2)	100%
Unconsolidated Affiliate(1)					
Proved Developed	135,245	1,860	4,295	172,175	86%
Proved Undeveloped	22,778	47	969	28,874	14%
Unconsolidated Affiliate(1)	158,023	1,907	5,264	201,049	100%
Total Combined	2,314,600	66,952	5,568	2,749,717	100%

(1) Amounts represent our approximate 49 percent equity interest in Four Star.

(2) Includes 1,357 Bcfe of proved developed producing reserves representing 53 percent of consolidated proved reserves and 356 Bcfe of proved developed non-producing reserves representing 14 percent of consolidated proved reserves at December 31, 2009.

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.

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The table below presents proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2009.

	Net Proved Reserves (MMcfe)
As Reported	
Consolidated	2,548,668
Unconsolidated Affiliate	201,049
Total Combined	2,749,717
Scenario 1	
Consolidated	2,776,166
Unconsolidated Affiliate	220,899
Total Combined	2,997,065
Scenario 2	
Consolidated	2,638,406
Unconsolidated Affiliate	208,498
Total Combined	2,846,904
Scenario 3	
Consolidated	2,469,363
Unconsolidated Affiliate	196,085
Total Combined	2,665,448

Scenario 1 The amounts represent our consolidated and unconsolidated proved reserves assuming spot prices at December 31, 2009 of $5.79 per MMBtu of natural gas and $79.36 per barrel of oil rather than the first day 12-month average U.S. price of $3.87 per MMBtu of natural gas and $61.18 per barrel of oil.

Scenario 2 The amounts represent our consolidated and unconsolidated proved reserves assuming prices were 10 percent higher than the first day 12-month average U.S. prices we used to determine proved reserves at December 31, 2009.

Scenario 3 The amounts represent our consolidated and unconsolidated proved reserves assuming prices were 10 percent lower than the first day 12-month average U.S. prices we used to determine proved reserves at December 31, 2009.

On December 31, 2009, we adopted the provisions of the Securities and Exchange Commission s (SEC s) final rule on Modernization of Oil and Gas Reporting (Final Rule). Among other things, the Final Rule revised the definition of proved reserves and required us to use a first day 12-month average price to estimate proved reserves rather than a period end spot price as required in prior periods. The adoption of the Final Rule resulted in lower natural gas and oil prices used to estimate our proved reserves at December 31, 2009 than would have been required under the previous rules. Had we used the spot price rather than the first day 12-month average price, our consolidated proved reserves would have been approximately 227 Bcfe higher than our reported proved reserves at December 31, 2009. Other than the first day 12-month average price change, the remaining provisions of the Final Rule had minimal impact on the Company s proved reserves. For a further discussion of the impact of the Final Rule on the Company s financial information, see Supplemental Natural Gas and Oil Operations.

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare for Four Star, our unconsolidated affiliate, has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is currently responsible for reserve reporting, strategy development, technical excellence and land administration. He has over 22 years of industry experience in various domestic and international engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates.

Ryder Scott Company, L.P. (Ryder Scott) conducted an audit of the estimates of the proved reserves prepared by us as of December 31, 2009. In connection with its audit, Ryder Scott reviewed 87 percent of the properties associated with our total proved reserves on a natural gas equivalent basis, representing 90 percent of the total discounted future net cash flows of these proved reserves. Ryder Scott also conducted an audit of the estimates we prepared of the proved reserves of Four Star as of December 31, 2009. In connection with the audit of these proved reserves, Ryder Scott reviewed 83 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 85 percent of the total discounted future net cash flows. Based on our data, technical processes and interpretations and procedures and methodologies utilized by us in determining our proved reserves, we believe our reported proved reserve amounts are reasonable. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing our reserves audit by Ryder Scott has a B.S. degree in mechanical engineering. He is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has over 18 years of reservoir engineering experience. His technical expertise is in the area of economic evaluations, reserves management systems, probabilistic modeling, pressure transient analysis, reservoir surveillance, production optimization, field operations, Enhanced Oil Recovery certification, computer application development and database management.

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 they are produced. Recovery of proved undeveloped (PUD) 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 PUD reserves and proved non-producing reserves are inherently 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.

We assess our PUD reserves on a quarterly basis. At December 31, 2009, we had 836 Bcfe of consolidated PUD reserves representing an increase of 230 Bcfe of PUD reserves compared to December 31, 2008. During 2009, we added 339 Bcfe of PUD reserves primarily due to our drilling activities in the Haynesville Shale and Holly/Kingston areas in our Central division and the Altamont Field in our Western division. In addition, we added 37 Bcfe of PUD reserves with the acquisition of natural gas and oil properties in the Altamont-Bluebell-Cedar Rim Field in Utah, also in our Western division. We had negative revisions of 73 Bcfe of PUD reserves, of which 33 Bcfe related to reserves that are not included in our current five-year development plan.

During 2009, we spent $186 million and converted approximately 11 percent or 69 Bcfe of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2009 reserve report, the amounts estimated to be spent in 2010, 2011 and 2012 to develop our consolidated worldwide proved undeveloped reserves are $316 million, $290 million and $223 million. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices.

Of the 836 Bcfe of PUD reserves at December 31, 2009, 71 Bcfe has remained undeveloped for five years or more, primarily in our Central division in major areas of very active drilling, including the Arklatex, Black Warrior and Raton basins. In these areas, we have ongoing drilling activities and a historical record of completing development of comparable long-term projects. Our properties in these major drilling areas are included in our current five-year development plan.

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2009, (ii) our interest in natural gas and oil wells at December 31, 2009 and (iii) our exploratory and development wells drilled during the years 2007 through 2009. 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						
Central	393,966	269,850	522,493	388,987	916,459	658,837
Western	405,145	319,967	975,040	760,674	1,380,185	1,080,641
Gulf Coast	345,952	196,523	462,289	358,195	808,241	554,718
Total United States	1,145,063	786,340	1,959,822	1,507,856	3,104,885	2,294,196
Brazil	47,377	14,492	494,346	124,605	541,723	139,097
Egypt			2,841,111	1,444,933	2,841,111	1,444,933
Worldwide Total	1,192,440	800,832	5,295,279	3,077,394	6,487,719	3,878,226

(1) Gross interest reflects the total acreage we participate 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 Utah (18 percent), New Mexico (16 percent), Texas (14 percent), Louisiana (10 percent), Oklahoma (9 percent) and Alabama (9 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (30 percent), Indiana (13 percent), the Gulf of Mexico (11 percent), Texas (11 percent), Wyoming (8 percent), and Colorado (7 percent). Approximately 9 percent, 10 percent and 6 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010, 2011 and 2012, respectively. Approximately 17 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010. Approximately 29 percent and 7 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010 and 2012, respectively. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or by entering into farm-out agreements with other operators.

	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2009	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2][3]	Gross[1]	Net[2]
Productive Wells								
United States								
Central	3,597	2,578	10	6	3,607	2,584	13	10
Western	1,397	953	560	372	1,957	1,325	4	3
Gulf Coast	1,428	1,055	24	21	1,452	1,076	2	2
Total	6,422	4,586	594	399	7,016	4,985	19	15
Brazil	9	2	5	2	14	4	2	1
Egypt							3	2
Worldwide Total	6,431	4,588	599	401	7,030	4,989	24	18

	Net Exploratory[2]			Net Development[2]		
	2009	2008	2007	2009	2008	2007
Wells Drilled						
United States						
Productive	61	163	214	69	278	238
Dry	2	2	12	2	7	1
Total	63	165	226	71	285	239
Brazil						
Productive			3	1		
Dry						
Total			3	1		
Egypt						
Productive						
Dry	2					
Total	2					
Worldwide						
Productive	61	163	217	70	278	238
Dry	4	2	12	2	7	1
Total	65	165	229	72	285	239

(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,

2009, we operated 4,589 of the 4,989 net productive wells.

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

Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, average sales prices received, average transportation costs 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:

	2009	**2008**	**2007**
Volumes:			
Consolidated Net Production Volumes			
United States			
Natural gas (MMcf)	214,718	229,518	238,021
Oil, condensate and NGL (MBbls)	5,548	6,371	7,664
Total (MMcfe)	248,006	267,745	284,005
Brazil			
Natural gas (MMcf)	3,826	3,185	4,295
Oil, condensate and NGL (MBbls)	100	124	157
Total (MMcfe)	4,426	3,928	5,237
Consolidated Worldwide			
Natural gas (MMcf)	218,544	232,703	242,316
Oil, condensate and NGL (MBbls)	5,648	6,495	7,821
Total (MMcfe)	252,432	271,673	289,242
Total (MMcfe/d)	691	742	792
Unconsolidated Affiliate Volumes(1)			
Natural gas (MMcf)	19,557	20,576	19,380
Oil, condensate and NGL (MBbls)	1,097	1,054	1,015
Total equivalent volumes (MMcfe)	26,139	26,899	25,470
MMcfe/d	72	74	70
Total Combined Volumes(1)			
Natural gas (MMcf)	238,101	253,279	261,696
Oil, condensate and NGL (MBbls)	6,745	7,549	8,836
Total equivalent volumes (MMcfe)	278,571	298,572	314,712
MMcfe/d	763	816	862

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	2009	2008	2007
Consolidated Prices and Costs per Unit:			
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Physical sales	$ 3.78	$ 8.51	$ 6.60
Including financial derivative settlements	$ 7.68	$ 8.26	$ 7.26
Brazil			
Physical sales	$ 4.84	$ 2.60	$ 2.61
Including financial derivative settlements	$ 4.22	$ 2.60	$ 2.61
Worldwide			
Physical sales	$ 3.80	$ 8.43	$ 6.53
Including financial derivative settlements(2)	$ 7.62	$ 8.18	$ 7.18
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Physical sales	$ 47.03	$ 82.96	$ 63.56
Including financial derivative settlements	$ 78.70	$ 77.42	$ 63.56
Brazil			
Physical sales	$ 60.88	$ 96.21	$ 70.86
Including financial derivative settlements	$ 60.88	$ 96.21	$ (4.41)
Worldwide			
Physical sales	$ 47.27	$ 83.21	$ 63.71
Including financial derivative settlements(2)	$ 78.38	$ 77.78	$ 62.19
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.28	$ 0.32	$ 0.27
Oil, condensate and NGL ($/Bbl)	$ 0.78	$ 0.98	$ 0.83
Worldwide			
Natural gas ($/Mcf)	$ 0.28	$ 0.31	$ 0.27
Oil, condensate and NGL ($/Bbl)	$ 0.77	$ 0.96	$ 0.81
Average Production Costs ($/Mcfe)			
United States			
Lease operating expenses	$ 0.70	$ 0.89	$ 0.86
Production taxes	0.21	0.44	0.31
Total production costs	$ 0.91	$ 1.33	$ 1.17
Brazil			
Lease operating expenses(3)	$ 5.19	$ 1.64	$ 1.63
Production taxes	0.68	0.58	0.51
Total production costs	$ 5.87	$ 2.22	$ 2.14
Worldwide			
Lease operating expenses(3)	$ 0.78	$ 0.90	$ 0.88
Production taxes	0.22	0.44	0.31
Total production costs	$ 1.00	$ 1.34	$ 1.19

(1) Represents our approximate 49 percent equity interest in the volumes of Four Star.

(2) Premiums related to natural gas derivatives settled during the year ended December 31, 2008 were $21 million. Had we included these premiums in our natural gas average realized prices in 2008, our realized price, including financial derivative settlements, would have decreased by $0.09/Mcf for the year ended December 31, 2008. We had no premiums related to natural gas derivatives settled during the years ended December 31, 2009 and 2007, or related to oil derivatives settled during the years ended December 31, 2009, 2008 and 2007.

(3)

Includes approximately $14 million of start-up costs in Camarupim Field in 2009 or $3.08 per Mcfe for Brazil and $0.05 per Mcfe worldwide.

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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:

	2009	2008	2007
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 87	$ 51	$ 964
Unproved	89	74	262
Development Costs	324	938	735
Exploration Costs:			
Delay rentals	5	6	6
Seismic acquisition and reprocessing	27	24	19
Drilling	323	408	373
Asset Retirement Obligations	36	19	38
Total full cost pool expenditures	891	1,520	2,397
Non-full cost pool expenditures	34	30	13
Total costs incurred	$ 925	$ 1,550	$ 2,410
Acquisition of additional investment in Four Star	$	$	$ 27
Brazil and Egypt[(1)]			
Acquisition Costs:			
Proved	$	$	$
Unproved	51	1	5
Development Costs	118	93	26
Exploration Costs:			
Seismic acquisition and reprocessing	3	13	6
Drilling	64	91	193
Asset Retirement Obligations	6		7
Total full cost pool expenditures	242	198	237
Non-full cost pool expenditures	4	13	1
Total costs incurred	$ 246	$ 211	$ 238
Worldwide[(1)]			
Acquisition Costs:			
Proved	$ 87	$ 51	$ 964
Unproved	140	75	267
Development Costs	442	1,031	761
Exploration Costs:			
Delay rentals	5	6	6
Seismic acquisition and reprocessing	30	37	25
Drilling	387	499	566

Asset Retirement Obligations	42	19	45
Total full cost pool expenditures	1,133	1,718	2,634
Non-full cost pool expenditures	38	43	14
Total costs incurred	$ 1,171	$ 1,761	$ 2,648
Acquisition of additional investment in Four Star	$	$	$ 27

(1) Costs incurred for Egypt were $81 million, $27 million and $10 million for the years ended December 31, 2009, 2008 and 2007.

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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, under long-term contracts, to Petrobras, Brazil s state-owned energy company. These long-term contracts include a gas sales agreement and a condensate sales agreement. The gas sales agreement provides for a price that adjusts quarterly based on a basket of fuel oil prices, while the condensate sales agreement provides for a price that adjusts monthly based on a Brent crude price less a fixed differential that will adjust annually. We 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 protect the economic assumptions associated with our capital investment programs. For a further discussion of these contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

The exploration and production business is highly competitive in the search for and acquisition of additional natural gas and oil reserves and in the sale of natural gas, oil and NGL. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms, our ability to access drilling and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in this 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 El Paso s overall price risk. In addition, we continue to manage and liquidate remaining legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2009, we managed the following types of contracts:

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, 2009:

	Affiliated Pipelines[1]	**Other Pipelines**
Daily capacity (MMBtu/d)	514,000	241,000
Expiration	2011 to 2028	2011 to 2026
Receipt points / Delivery points	Various	Various

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

Legacy natural gas contracts. As of December 31, 2009, we had seven significant physical natural gas contracts with power plants associated with our legacy trading activities, including our Midland Cogeneration Venture (MCV) supply agreement. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2011 to 2028, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d.

Legacy power contracts. As of December 31, 2009, we had three derivative contracts that require us to swap locational differences in power prices between three power plants in the Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub. In total, these contracts require us annually to swap locational differences in power prices on approximately 3,700 GWh from 2010 to 2012, 2,400 GWh for 2013 and 1,700 GWh from 2014 to April 2016. Additionally, these contracts require us to provide approximately 1,700 GWh of power per year and approximately 71 GW of installed capacity per year in the PJM power pool through April 2016.

Markets, Competition and Regulatory Environment

Our Marketing segment operates in a highly competitive environment, competing on the basis of price, 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.

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Power Segment

As of December 31, 2009, our Power segment primarily included the ownership and operation of our remaining investment in a power generation project and a pipeline facility. These facilities are subject to regulation by government agencies and the regulatory structure is subject to change over time, and as a result, we are subject to certain political risks related to the facilities. Each of these assets is further described below:

Power Project	Area	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas

Pipeline	El Paso Ownership Interest (Percent)	Gross KM(1)	Design Capacity(1) (MMcf/d)	Average 2009 Throughput(1) (BBtu/d)
Bolivia to Brazil	8	3,150	1,059	793

(1) Amounts are not adjusted for our ownership percentage.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 13.

Employees

As of February 22, 2010, we had 4,991 full-time employees, of which 98 employees are subject to collective bargaining arrangements.

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Executive Officers of the Registrant

Our executive officers as of February 26, 2010, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	Chairman, President and Chief Executive Officer of El Paso	2003	50
John R. Sult	Senior Vice President and Chief Financial Officer of El Paso	2005	50
Brent J. Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	48
James C. Yardley	Executive Vice President, Pipeline Group	2005	58
D. Mark Leland	Executive Vice President of El Paso and President of Midstream	2005	48
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	53
Susan B. Ortenstone	Senior Vice President and Chief Administrative Officer of El Paso	2003	53
James J. Cleary	President of Western Pipeline Group	2005	55
Dane E. Whitehead	Senior Vice President, Strategy and Enterprise Business Development of El Paso	2009	48

Douglas L. Foshee has been Chairman of the Board of Directors of El Paso Corporation since May 2009 and President, Chief Executive Officer and a director of El Paso since September 2003. Prior to joining El Paso, Mr. Foshee served as Executive Vice President and Chief Operating Officer of Halliburton Company 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. Prior to assuming his position at Halliburton, Mr. Foshee served as President, Chief Executive Officer and Chairman of the Board of Nuevo Energy Company and Chief Executive Officer and Chief Operating Officer of Torch Energy Advisors Inc. Mr. Foshee presently serves as a director of Cameron International Corporation and is a trustee of AIG Credit Facility Trust. Mr. Foshee serves as Chairman of the Federal Reserve Bank of Dallas, Houston Branch. Mr. Foshee also serves on the Board of Trustees of Rice University and serves as a member of the Council of Overseers for the Jesse H. Jones Graduate School of Management. He is a member of various other civic and community organizations. Mr. Foshee also serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

John R. Sult has been Senior Vice President and Chief Financial Officer of El Paso since November 2009. Mr. Sult previously served as Senior Vice President and Controller of El Paso from November 2005 to November 2009. He has served as Senior Vice President and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. since November 2009 and Senior Vice President, Chief Financial Officer and Controller from August 2007 to November 2009. Mr. Sult served as Senior Vice President, Chief Financial Officer and Controller of El Paso s Pipeline Group from November 2005 to November 2009. Mr. Sult was Vice President and Controller for Halliburton Energy Services from August 2004 to October 2005. Mr. Sult also serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

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 and asset management capacities for Burlington Resources Inc., including the Chief Engineering role from 2000 to 2004. He was a member of the Burlington Executive Committee from 2001 to 2006. Mr. Smolik also serves on the Boards of the American Exploration and Production Council, America s Natural Gas Alliance and the Independent Petroleum Association of America.

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James C. Yardley has been Executive Vice President of El Paso with responsibility for the regulated pipeline business unit since August 2006. He has served as President of Tennessee Gas Pipeline Company since February 2007 and Chairman of the Board since August 2006. Mr. Yardley has been Chairman of El Paso Natural Gas Company since August of 2006 and has served as President of Southern Natural Gas Company since May 1998. Mr. Yardley 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 is currently a member of the board of directors of Scorpion Offshore Ltd. He also serves on the Board of Interstate Natural Gas Association of America and previously served as its Chairman. Mr. Yardley also serves as Director, President and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

D. Mark Leland has been Executive Vice President of El Paso and President of El Paso s Midstream business unit since October 2009. Mr. Leland previously served as Executive Vice President and Chief Financial Officer of El Paso from August 2005 to November 2009. He served as Executive Vice President of El Paso Exploration & Production Company from January 2004 to August 2005, and as Chief Financial Officer and a director from April 2004 to August 2005. Mr. Leland served as Senior Vice President and Chief Operating Officer of GulfTerra Energy Partners, L.P. and its general partner 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 serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

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. Mr. Baker previously served as Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Mr. Baker serves as Executive Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

Susan B. Ortenstone has been Chief Administrative Officer of El Paso since October 2009 and Senior Vice President 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. Ms. Ortenstone serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

James J. Cleary has been a director and President of El Paso Natural Gas Company since January 2004. Mr. Cleary has been a member of the Management Committee of Colorado Interstate Gas Company since November 2007 and President since January 2004. He previously served as Chairman of the Board of both 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. Mr. Cleary serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

Dane E. Whitehead has been Senior Vice President of Strategy and Enterprise Business Development of El Paso since October 2009. Mr. Whitehead previously served as Senior Vice President and Chief Financial Officer for El Paso Exploration and Production Company from May 2006 to October 2009. From October 1993 to April 2006, Mr. Whitehead held various positions at Burlington Resources Inc. including serving as Vice President, Controller and Chief Accounting Officer.

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 failures, 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. In addition, although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns as a result of global emissions of greenhouse gas could have a negative impact upon our operations in the future, particularly with regard to the facilities of our Pipeline and Exploration and Production segments that are located in or near the Gulf of Mexico and other coastal regions.

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, limits on our maximum recovery, and do not cover all risks. There is also the risk that our coverages will change over time in light of increased premiums or changes in the terms of the insurance coverages that could result in our decision to either terminate certain coverages, increase our deductibles and self-insurance levels, or decrease our maximum recoveries. In addition, there is a risk that our insurers may default on their coverage obligations. 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.

The results of our pipeline business are impacted by the volumes of natural gas we transport or store and the prices we are able to charge for doing so. The volumes of natural gas we are able to transport and store depend on the actions of third parties and are beyond our control. Such actions include factors that impact our customers demand and producers supply, including factors that negatively impact our customers need for natural gas from us, as well as the continued availability of natural gas production and reserves connected to our pipeline systems. Further, the following factors, most of which are also beyond our control, may unfavorably impact our ability to maintain or increase current throughput, or to remarket unsubscribed capacity on our pipeline systems:

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service area competition;

price competition;

expiration or turn back of significant contracts;

changes in regulation and action of regulatory bodies;

weather conditions that impact natural gas throughput and storage levels;

weather fluctuations or warming or cooling trends that may impact demand in the markets in which we do business, including trends potentially attributed to climate change;

drilling activity and decreased availability of conventional gas supply sources and the availability and timing of other natural gas supply sources, such as LNG and gas shale supplies;

continued development of additional sources of gas supply that can be accessed;

decreased natural gas demand due to various factors, including economic recession (as further discussed below), availability of alternate energy sources and increases in prices;

legislative, regulatory, or judicial actions, such as mandatory renewable portfolio standards and greenhouse gas (GHG) regulations and/or legislation that could result in (i) changes in the demand for natural gas and oil, (ii) changes in the availability of or demand for alternative energy sources such as hydroelectric and nuclear power, wind and solar energy and/or (iii) changes in the demand for less carbon intensive energy sources;

availability and cost to fund ongoing maintenance and growth projects, especially in periods of prolonged economic decline;

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;

our ability to achieve targeted annual operating and administrative expenses primarily by reducing internal costs and improving efficiencies from leveraging a consolidated supply chain organization;

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 pipeline 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, cost of capital, taxes 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.

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The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Substantially all of our pipeline revenues are generated under transportation and storage 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. For additional information on the expiration of our contract portfolio, see Part II, Item 7, Management s Discussion and Analysis of Financial Conditions and Results of Operations. In particular, our ability to extend and replace contracts could be adversely affected by factors we cannot control, as discussed in more detail above. In addition, changes in state regulation of local distribution companies may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire.

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. Consequently, a significant prolonged downturn in natural gas and oil prices could have a material adverse effect on our financial condition, results of operations and liquidity. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand, including changes in supply and demand due to general economic conditions and weather;
- availability and adequacy of gathering, processing and transportation facilities;
- energy legislation and regulation, including potential changes associated with GHG emissions and renewable portfolio standards;
- federal and state taxes, if any, on the sale or transportation of natural gas and NGL;
- the price and availability of supplies of alternative energy sources; and
- the level of imports, including the potential impact of political unrest among countries producing oil and LNG, as well as the ability of certain foreign countries to maintain natural gas and oil price, production and export controls.

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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, including the potential impact of delays and increased costs caused by certain environmental and landowner groups with interests along the route of our pipelines;
- the ability to access sufficient capital at reasonable rates to fund expansion projects, especially in periods of prolonged economic decline when we may be unable to access the capital markets;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes, regulations, and orders, such as environmental requirements, including climate change requirements that delay or 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 or to commence and complete construction 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, delays in construction 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/or demand; 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. There is also the risk that the downturn in the economy and its negative impact upon natural gas demand may result in either slower development in our expansion projects or adjustments in the contractual commitments supporting such projects. As a result, new facilities may be delayed or may not achieve our expected investment return, which could adversely affect our results of operations, cash flows or financial position.

Our pipeline systems depend on certain key customers and producers for a significant portion of their revenues. The loss of any of these key customers could result in a decline in our systems revenues.

Our systems rely on a limited number of customers for a significant portion of our systems revenues. For the year ended December 31, 2009, the four largest natural gas transportation customers for each of TGP, CIG, EPNG and SNG accounted for approximately 22 percent, 60 percent, 52 percent and 44 percent of their respective operating revenues. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts or otherwise, could have a material adverse effect on our financial condition and results of operations.

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We are exposed to the credit risk of our pipeline customers and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of delays in payment as well as losses resulting from nonpayment and/or nonperformance by our pipeline customers, including default risk associated with adverse economic conditions. Our credit procedures and policies may not be adequate to fully eliminate customer credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future customers fail to pay and/or perform and we are unable to remarket the capacity, our business, the results of our operations and our financial condition could be adversely affected. We may not be able to effectively remarket capacity during and after insolvency proceedings involving a shipper.

We are exposed to the credit and performance risk of our key contractors and suppliers.

As an owner of large energy infrastructure, including significant capital expansion programs, we rely on contractors for certain construction and drilling operations and we rely on suppliers for key materials and supplies, including steel mills and pipe manufacturers. There is a risk that such contractors and suppliers may experience credit and performance issues that could adversely impact their ability to perform their contractual obligations with us. This could result in delays or defaults in performing such contractual obligations, which could adversely impact our financial condition and results of operations.

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

Our future financial condition, revenues, results of operations, cash flows and future rate of growth of our exploration and production business 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.

Further, because the majority of our proved reserves at December 31, 2009 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 the first day 12-month average natural gas and oil prices could result in additional downward revisions of our reserves and additional full cost ceiling test write-downs 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.

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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 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, limit or restrict the use of hydraulic fracturing in our drilling operations, limit or restrict our access to water rights (including disposal of water and other fluids in our operations), 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 ability to receive certain government approvals or permits on a timely basis on terms acceptable to us;
- 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 at reasonable rates to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics especially in periods of prolonged economic decline when we may be unable to access the capital markets.

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.

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, limits on our maximum recovery and do not cover all risks, including potential environmental fines and penalties. In addition, there is a risk that our insurers may default on their coverage obligations. As a result, our future results of operations, cash flows or financial condition could be adversely affected if a significant event occurs that is not fully covered by insurance.

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.

All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules require that the standard of reasonable certainty be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as 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. Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which it is based, and on engineering and geological interpretations and judgment. 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. In addition, 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 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) 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 first day 12-month average 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, changes in commodity prices or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially. For estimated quantities of proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves as of December 31, 2009, see Item 1, Business, Natural Gas and Oil Properties.

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. In addition, as the portion of our proved reserve base that consists of unconventional sources increases, the costs of finding, developing and producing those reserves may require capital expenditures that are greater than more conventional sources. 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 accounting hedges or do not qualify as hedges, changes in commodity prices, interest rates, counterparty non-performance risks, 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 enter into derivative contracts to manage 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. To the extent that we enter into fixed price derivative contracts, we could experience losses and be required to pay cash to the extent that commodity prices or interest rates were to increase above the fixed price. 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. In this regard, there is proposed federal legislation that would require commodity derivative transactions that are currently traded over-the-counter to be traded over regulated exchanges that could require collateral posting for many of our derivative transactions that do not currently have collateral posting requirements and therefore would negatively impact our working capital requirements. 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 8.

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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, pipeline projects in Mexico and a power project in Pakistan, 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 which include:

- 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.

The midstream business may be subject to additional risks associated with fluctuations in energy commodity prices.

The midstream sector generally includes the gathering, transporting, processing, fractionating and storing of natural gas, NGLs and oil. The pricing for each of these hydrocarbon products has been volatile over time. In addition, the relative pricing between these hydrocarbon products has been volatile, which may affect fractionation spreads and the profitability of the business. Changes in prices and relative price levels may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we may provide services.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could affect the profitability of our midstream business.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, could adversely affect the profitability of our future midstream business. Various factors could impact the demand for NGL products, including general economic conditions, reduced demand by consumers for the end products made with NGL products, extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of NGL processing and transportation capacity, government regulations affecting prices and production levels of natural gas, NGLs or the content of motor fuels.

We will face competition from third parties in our midstream businesses.

As we re-enter the midstream business, we will be competing with third parties to gather, transport, process, fractionate, store or handle hydrocarbons. Although we will attempt to leverage the synergies between our pipeline and exploration and production businesses, most of these third parties will have existing facilities and as a result initially have more scale and personnel than us. Therefore, there can be no assurances on how successful our re-entry into the midstream business will be.

We will face additional reserve and volumetric risk in our midstream business.

Although the revenues in our pipeline business are typically collected in the form of demand or reservation charges and are not dependent upon reserves or throughput levels, many transactions in the midstream business involve additional reserve and throughput risk. For example, natural gas and oil reserves committed to gathering and processing facilities may not be as large as expected, the life of the reserves may not be as long as expected or the producers may elect not to develop such reserves. We also cannot influence or control the production or the speed of development of the third-party natural gas we transport or process. The reserves committed will naturally decline overtime and our ability to attract new reserves in competition with third parties to replace these declining supplies is uncertain. Furthermore, the rate at which production from these reserves declines may be greater than we anticipate. As a result, we may face additional reserve and throughput risk in our midstream business beyond what we typically experience in our pipeline business.

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 including engineers and other technical personnel. If we are unable to retain our current employees (many of which are retirement eligible) or recruit new employees of comparable knowledge and experience, our business could be negatively impacted.

Risks Related to Legal and Regulatory Matters

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

We are subject to various governmental investigations from time to time, including investigations by the FERC and the U.S. Department of Transportation Office of Pipeline Safety. The results of any investigation 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.

Many of our pipelines periodically file to adjust their rates charged to their customers. In establishing those rates, 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. Depending on the specific risks faced by us and the companies included in the proxy group, the FERC may establish rates that are not acceptable to us and have a negative impact on our cash flows, profitability and results of operations. In addition, pursuant to laws and regulations, our existing rates may be challenged by complaint. The FERC commenced several complaint proceedings in 2009 against unaffiliated pipeline systems to reduce the rates they were charging their customers. There is a risk that the FERC or our customers could file similar complaints on one or more of our pipeline systems and that a successful complaint against our pipelines rates could have an adverse impact on our cash flows and results of operations.

We formed EPB, 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 EPB.

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.

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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. In addition, although we have environmental management systems to manage our compliance obligations, fines and penalties can result 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 U.S. Environmental Protection Agency (EPA) under the Comprehensive Environmental Response, Compensation and Liability Act), as well as damage claims arising out of the contamination of properties or impact on natural resources. Although we believe we have processes and systems in place to establish 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 Item 3, Legal Proceedings and Part II, Item 8, Financial Statements and Supplementary Data, Note 13.

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;
- forecasting cash flow timing to implement proposed pollution control and cleanup costs;
- receiving regulatory approval for remediation programs;
- quantifying liability under environmental laws that may impose joint and several liability on potentially responsible parties and managing allocation responsibilities;
- evaluating and understanding environmental laws and regulations, including their interpretation and enforcement;
- interpreting whether various maintenance activities performed in the past and currently being performed required pre-construction permits pursuant to the Clean Air Act; and
- changing environmental laws and regulations that may increase our costs.

In addition to potentially increasing the cost of our environmental liabilities, changing environmental laws and regulations may increase our future compliance costs, such as the costs of complying with ozone standards, emission standards with regard to our reciprocating internal combustion engines on our pipeline systems, GHG reporting and potential mandatory GHG emissions reductions. Future environmental compliance costs relating to GHGs associated with our operations are not yet clear. For a further discussion on GHGs, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, Commitments and Contingencies.

Although it is uncertain what impact legislative, regulatory, and judicial actions might have on us until further definition is provided in those forums, there is a risk that such future measures 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 or pay taxes related to our GHG and other emissions, and (v) administer and manage an emissions program for GHG and other emissions. Changes in regulations, including adopting new standards for emission controls for certain of our facilities, could also result in delays in obtaining required permits to construct or operate our facilities. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance in the rates charged by our pipelines and in the prices at which we sell natural gas and oil, our ability to recover such 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 regulations and legislation.

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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 13). We also have other contingent liabilities and exposures. In addition, we have significant benefit plan obligations that could be negatively impacted by changes that might arise out of potential health care and pension reform legislation. 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 stable outlook by Moody s Investor Service and BB- with a negative outlook by Standard & Poor s. These ratings have increased our cost of capital and our operating costs. There is a risk that these credit ratings may be adversely affected in the future as the credit rating agencies continue to review our leverage, liquidity and credit profile. Any reduction in our credit rating could impact our ability, as well as the ability of El Paso Pipeline Partners and our pipeline subsidiaries, to access the capital markets. These changes could also impact our cost of capital as well as that of our subsidiaries. As a result of the volatility in the financial markets and the capital commitments of our pipeline group, we have been maintaining greater liquidity levels. However, if commodity prices remain at current levels or continue to decline and our access to capital markets is restricted, then such liquidity levels may not be adequate to manage our business and our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 12, for a further discussion of our debt.

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

Our debt and other financing obligations contain restrictive covenants, including debt to earnings before interest, income taxes, depreciation and amortization (EBITDA) and fixed charges to EBITDA covenants in our revolving credit agreement, and contain cross default provisions. In light of the volatility in the financial markets and a reduction in access to capital, these covenants may become more restrictive over time. 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.

Adverse general global economic conditions could negatively affect our operating results, financial condition, liquidity or our share price.

We are subject to the risks arising from adverse changes in general global economic conditions including recession or economic slowdown. The global economy is experiencing a recession and the financial markets have experienced extreme volatility and instability. In response, over the last year we announced reductions in our capital plan as well as several other actions, including non-core asset sales to address these general economic conditions. Adverse general economic conditions as well as restrictions on the ability of parties to access capital markets could negatively impact our ability to sell assets or obtain partners on certain projects on a timely basis. In addition, such conditions if they persist could negatively impact the amount of proceeds from such sales or joint venture arrangements.

If we experience prolonged periods of recession or slowed economic growth in the U.S., demand growth from consumers for natural gas and oil produced and transported by us on our natural gas transportation systems may continue to decrease, which could impact the development of our future expansion projects. Additionally, our access to capital could be impeded and the cost of capital we obtain could be higher. We are subject to the risks arising from changes in legislation and regulation associated with any such recession or prolonged economic slowdown, including creating preferences for renewables, as part of a legislative package to stimulate the economy. In addition, the general volatility in the financial markets and the economy may also affect the return expectations of our investors and could adversely impact the value of our securities. Finally, our pension plans were underfunded at December 31, 2009, due primarily to the recent adverse economic conditions. While we do not currently expect to make additional contributions in 2010, we may be required to make additional pension plan contributions in the future if adverse economic conditions continue. 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 in addition to general economic conditions discussed above, 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.

Although a substantial portion of our debt capital structure has fixed interest rates, changes in market conditions, including potential increases in the deficits of federal and state governments, could have a negative impact on interest rates that could cause our financing costs to increase. Rising interest rates could also negatively impact our investment in El Paso Pipeline Partners as changes in interest rates may affect the yield requirements of investors in its units.

Our available liquidity could be impacted by decreases in our natural gas and oil reserves under our borrowing base facility of our exploration and production subsidiary.

We maintain $1.3 billion of our liquidity through the borrowing base facilities of our exploration and production subsidiary. A downward revision of our natural gas and oil reserves, due to future declines in commodity prices, performance revisions or otherwise, could require a redetermination of the borrowing base and could negatively impact our ability to source funds from such facilities in the future.

Our ability to sell assets or obtain partners on projects, to maintain adequate liquidity may be impacted by adverse general economic conditions.

We currently are projecting to sell certain assets during 2010. In addition, it is possible that we may be required to sell assets or obtain partners on projects in order to maintain adequate levels of liquidity. Adverse general economic conditions as well as restrictions on the ability of parties to access capital markets could negatively impact our ability to sell such assets or obtain partners on such projects on a timely basis, as well as negatively impact the amount of proceeds from such sales or joint venture arrangements.

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Our inability to satisfy all conditions precedent under the transaction with Global Infrastructure Partners (GIP) associated with the development, construction and financing of the Ruby pipeline project could require us to pay all amounts owed to GIP under the associated equity and debt instruments.

During the third quarter of 2009, we entered into an agreement with GIP, whereby it will invest up to $700 million and acquire a 50 percent indirect interest in our Ruby pipeline project. To the extent that all conditions precedent set forth in the agreements with GIP are not satisfied, including obtaining certain regulatory approvals, obtaining certain financing commitments and completing the pipeline, then we are obligated to repurchase its equity interests and repay all amounts owed under the loan arrangements. These repayment obligations are secured by various interests in Ruby Pipeline Holding Company, L.L.C. (Ruby), Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains) and our common units held in El Paso Pipeline Partners, L.P. Adverse economic conditions, as well as restrictions on our ability to access the capital markets could negatively impact our ability to meet such obligations, as well as permit GIP to foreclose on such security interests.

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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

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 13, and is incorporated herein by reference.

Natural Buttes. In May 2004, the EPA issued a Compliance Order to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. In September 2005, the matter was referred to the U.S. Department of Justice (DOJ). CIG entered into a tolling agreement with the United States and conducted settlement discussions with the DOJ and the EPA. While conducting some testing at the facility, CIG discovered that three generators installed in 1992 may have been emitting oxides of nitrogen at levels which suggested the facility should have obtained a Prevention of Significant Deterioration (PSD) permit when the generators were first installed, and CIG promptly reported those test data to the EPA. CIG executed a Consent Decree with the DOJ and has paid a total of $1.02 million to settle all of these Title V and PSD issues at the Natural Buttes Compressor Station. In addition, as required by the Consent Decree, ambient air monitoring at the Uintah Basin commenced on January 1, 2010 for a period of two years. In November 2009, CIG sold its Natural Buttes compressor station and gas processing plant to a third party for $9 million.

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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 23, 2010, we had 29,916 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
2009			
Fourth Quarter	$11.37	$ 8.94	$0.01
Third Quarter	10.85	8.00	0.05
Second Quarter	10.91	6.10	0.05
First Quarter	9.52	5.22	0.05
2008			
Fourth Quarter	$12.57	$ 5.32	$0.05
Third Quarter	22.47	11.25	0.05
Second Quarter	22.10	15.80	0.04
First Quarter	18.27	14.83	0.04

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2004 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 2008 and 2009 included the following companies: Anadarko Petroleum Corp., Apache Corp., CenterPoint Energy Inc., Chesapeake Energy Corp., Devon Energy Corp., Dominion Resources, Inc., Enbridge, Inc., EOG Resources Inc., EQT Corp., National Fuel Gas Co., Newfield Exploration Co., NiSource, Inc., Noble Energy Inc., ONEOK, Inc., Pioneer Natural Resources Co., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., TransCanada Corp., Williams Companies, Inc., and XTO Energy Inc.

COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS

	12/04	12/05	12/06	12/07	12/08	12/09
El Paso Corporation	$100	$118.61	$150.75	$171.76	$ 79.15	$101.40
S&P 500 Stock Index	$100	$104.91	$121.48	$128.16	$ 80.74	$102.11
S&P 500 Oil & Gas Storage & Transportation Index(1)	$100	$132.10	$157.13	$179.50	$ 89.21	$124.66
Peer Group (2008 & 2009)	$100	$139.85	$150.42	$193.68	$126.90	$196.69

(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 24, 2010, we declared a quarterly dividend of $0.01 per share of our common stock, payable on April 1, 2010, to shareholders of record as of March 5, 2010. 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 we are unable to comply with our fixed charge ratio, our ability to pay additional dividends would be restricted.

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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 December 31, 2009 and 2008 and for each of the three years in the period ended December 31, 2009 is derived from the audited consolidated financial statements included in this Report on Form 10-K in Item 8, Financial Statements and Supplementary Data. The selected financial data as of December 31, 2007, 2006 and 2005 and for each of the two years in the period ended December 31, 2006 are derived from unaudited consolidated financial statements adjusted to reflect the adoption of the new presentation and disclosure requirements for noncontrolling interests. The selected financial data is not necessarily indicative of results to be expected in future periods and should be read together with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8, Financial Statements and Supplementary Data included in this Report on Form 10-K.

	As of or for the Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,631	$ 5,363	$ 4,648	$ 4,281	$ 3,359
Income (loss) from continuing operations	$ (474)	$ (789)	$ 442	$ 532	$ (505)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (576)	$ (860)	$ 1,073	$ 438	$ (633)
Earnings (loss) per common share from continuing operations attributable to El Paso Corporation s common stockholders:					
Basic	$ (0.83)	$ (1.24)	$ 0.57	$ 0.73	$ (0.82)
Diluted	$ (0.83)	$ (1.24)	$ 0.57	$ 0.72	$ (0.82)
Cash dividends declared per common share	$ 0.16	$ 0.18	$ 0.16	$ 0.16	$ 0.16
Basic average common shares outstanding	696	696	696	678	646
Diluted average common shares outstanding	696	696	699	739	646
Financial Position Data:					
Total assets	$22,505	$23,668	$24,579	$27,261	$31,840
Long-term financing obligations, less current maturities	13,391	12,818	12,483	13,329	16,282
Preferred stock of subsidiary	145				
Total equity	3,991	4,596	5,845	4,217	3,420

Factors Affecting Trends. During 2009 and 2008, we recorded non-cash full cost ceiling test charges of $2.1 billion and $2.7 billion, principally as a result of declines in commodity prices. In 2007, we sold our ANR pipeline system and related assets and also completed the initial public offering of common units in EPB, our master limited partnership. Our 2005 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, under which we sold a substantial amount of non-core assets to reduce our long-term financing obligations resulting in a significant reduction of our net income during that year.

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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 in Item 1A, Risk Factors. 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 2009 performance and an outlook for 2010;

Results of Operations includes a year-over-year analysis 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 of our sources and uses of cash, available liquidity, our liquidity outlook for 2010, an overview of cash flow activity during 2009, and additional factors that could impact our liquidity;

Off Balance Sheet Arrangements, Contractual Obligations, and Commodity-Based Derivative Contracts includes a discussion 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 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, which provide a stable base of earnings and cash flow with a significant backlog of committed expansion projects. We are also a large independent natural gas and oil producer focused on generating competitive financial returns through disciplined capital allocation 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, our costs to explore, develop, and produce natural gas and oil, and the volumes we are able to produce, among other factors. Our long-term profitability in each of our operating segments will be primarily influenced by the following factors:

Pipelines

- Successfully executing on our remaining backlog of committed expansion projects on time and on budget and developing new growth projects in our market and supply areas;

- Contracting and recontracting pipeline capacity with our customers;

- Maintaining or obtaining approval by the FERC of acceptable rates, terms of service, and expansion projects; and

- Improving operating efficiency.

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Exploration and Production

- Growing our natural gas and oil proved reserve base and production volumes through successful drilling programs;
- 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 be affected by any impacts of the volatility in the financial and commodity markets, 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 2009 Financial and Operational Performance

During 2009, we generated significant operating cash flows from our core pipeline and exploration and production businesses while executing on our plan outlined in late 2008 to respond to the volatility in the financial markets, energy industry and the global economy. During 2009, we placed several pipeline expansion projects into service, obtained a partner on our Ruby project and secured financing for a portion of our remaining pipeline backlog. In our exploration and production business, despite a lower level of drilling activity, lower natural gas prices and lower capital spending in 2009, we expanded our resource inventory with low-risk onshore reserves, lowered our operating costs, and managed our exposure to a volatile commodity price environment through an expanded hedging program through 2011. However, due to lower natural gas prices at the end of the first quarter of 2009, we recorded approximately $2.1 billion of non-cash ceiling test charges, primarily on our domestic full cost pool, which significantly impacted our overall financial results. We believe the stability of our pipeline earnings coupled with the hedging program in our exploration and production business will continue to protect our earnings base and cash flows from operations. Additionally, we believe we have managed our capital program to provide for our pipeline backlog while retaining substantially all of our existing natural gas and oil resource positions for future exploration and production activities.

The following table provides 2009 operational highlights in our core businesses:

Area of Operations	Significant Highlights
Pipelines	Continued to make progress on our backlog of expansion projects placing four growth projects in service on budget, including the Carthage Expansion, the Totem Gas Storage project, the WIC Piceance Lateral expansion, and the Concord Lateral Expansion
	Obtained a 50 percent partner for our Ruby pipeline project and completed $2.1 billion of financings to partially fund our pipeline backlog
	Successfully settled the SNG rate case with contract extensions through August 2013 and a rate moratorium until September 2012
Exploration and Production	Achieved an overall domestic drilling success rate of 96 percent
	Shifted focus to more unconventional resource plays domestically including the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont-Bluebell-Cedar Rim Field fractured tight sands in Utah
	Brought Camarupim project on line in Brazil and found hydrocarbons in two wells drilled in Egypt
	Managed price risk through derivative contracts on 2009, 2010 and 2011 natural gas

production as well as our 2009 and 2010 oil production

In our non-core Power segment, we completed the sale of our interests in the Porto Velho power generation facility and the Argentina-to-Chile pipeline to our partners in these projects. In October 2009, we also announced our re-entry into the midstream business where we believe that the movement to more unconventional supply basins will present future opportunities.

Outlook for 2010

We expect that our pipeline operations will continue to provide a strong base of earnings and operating cash flow in 2010. We expect to have relatively stable rates within our pipeline group, with the majority of our pipelines not having any outstanding rate cases pending before the FERC. We have also increased our 2010 capital expenditure program for this business to approximately $2.9 billion and have a backlog of growth projects which we will remain focused on implementing both on time and on budget. We currently plan to place three more projects in service by the end of 2010. However, the largest portion of our capital program is related to the anticipated construction of our Ruby pipeline project. Finally, we will consider additional opportunities with our master limited partnership (MLP), EPB, as the markets permit.

In our exploration and production business, we also expect to generate significant operating cash flow and earnings, although additional non-cash ceiling test charges could impact our earnings in the future as a result of future declines in natural gas and oil prices. We anticipate spending approximately $1.1 billion in capital expenditures in this business during 2010, with approximately one-half of the domestic capital program targeted for our Haynesville, Altamont and Eagle Ford areas and $175 million planned for our Brazil and Egypt programs. Our planned average daily production for 2010 is expected to range between 740 MMcfe/d and 780 MMcfe/d, including approximately 60 MMcfe/d to 65 MMcfe/d from our ownership interest in the production of Four Star. Although commodity prices remain at lower levels, we have expanded our financial derivative contracts in place for 2010 providing $6.41 average floors on approximately 85 percent of our estimated consolidated natural gas production and $75 average floors on approximately 90 percent of our estimated consolidated oil production. These contracts also allow for potential upside.

As of December 31, 2009, we had approximately $1.8 billion of available liquidity. In 2010, we have an estimated $4.1 billion capital program which provides for funding our pipeline backlog as well as exploration and production reserves growth. Our 2010 capital program consists of $2.9 billion related to our pipeline business (including 100% of Ruby pipeline capital) and approximately $1.1 billion related to our exploration and production business. While our 2010 pipeline capital requirements are significant, our 2011 requirements decline significantly and by the end of 2011 most of our backlog will be placed in service. Accordingly, in 2012, we expect to benefit from the earnings generated from our substantially completed pipeline backlog and greater exploration and production volumes. In 2010, our debt maturities are nominal. We believe we are well positioned to meet our obligations based on the anticipated performance of our core businesses, our financing actions taken to date and planned for 2010, and the additional steps noted below to enhance our liquidity. For a further discussion, see *Liquidity and Capital Resources*.

In November 2009, we announced additional steps we would take to further improve our financial flexibility to fund our core businesses. The additional steps are designed to (i) provide incremental funding for our 2010 capital programs focused on our industry-leading pipeline backlog of growth opportunities and growing our unconventional natural gas drilling inventory in our exploration and production business, (ii) improve our overall cost structure, (iii) protect our credit profile, (iv) manage commodity risk and (v) enhance overall shareholder returns. These steps were:

- A reduction of $150 million in annual operating and administrative expenses achieved primarily by reducing internal costs and improving efficiencies from leveraging a consolidated supply chain organization, a portion of which was realized in 2009.

- The sale of $300 million to $500 million of assets during 2010. In February 2010, we entered into an agreement to sell our interest in Mexican pipeline and compression assets for approximately $300 million; and

- A reduction in our quarterly dividend from $0.05 per share to $0.01 per share, which will result in annual cash savings of approximately $112 million.

We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements as well as address further changes in the financial and commodity markets.

Results of Operations

Overview

As of December 31, 2009, 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 power and pipeline assets in South America and Asia. 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) as a measure 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 more effectively our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense, (ii) income taxes, and (iii) net income attributable to noncontrolling interests so that our 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 (loss), income (loss) before income taxes 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:

	2009	2008	2007
		(In millions)	
Segment			
Pipelines	$ 1,416	$ 1,273	$ 1,265
Exploration and Production	(1,349)	(1,448)	909
Marketing	20	(104)	(202)
Power	(25)	1	(37)
Segment EBIT(1)	62	(278)	1,935
Corporate and other	8	124	(283)
Consolidated EBIT(1)	70	(154)	1,652
Interest and debt expense	(1,008)	(914)	(994)
Income tax benefit (expense)	399	245	(222)
Discontinued operations, net of income taxes			674
Net income (loss) attributable to El Paso Corporation	(539)	(823)	1,110
Net income attributable to noncontrolling interests	65	34	6
Net income (loss)	$ (474)	$ (789)	$ 1,116

(1) 2007 EBIT represents EBIT from continuing operations.

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.

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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 2009 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.	79
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.	21

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, changes in supply and demand, 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 our 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 the process of renewing expiring contracts to limit the risk of significant impacts on our revenues. 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 the 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 maximum rates allowed under our tariffs, although at times, we enter into firm transportation contracts at amounts that are less than these maximum rates to remain competitive. We refer to the difference between the maximum rates allowed under our tariff and the contractual rate we charge as discounts . Our existing contracts mature at various times and in varying amounts of throughput capacity. The weighted average remaining contract term for our active contracts is approximately five years as of December 31, 2009.

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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, 2009, including those with terms beginning in 2010 or later:

	Contracted Capacity BBtu/d	Percent of Total	Reservation Revenue (In millions)	Percent of Total Reservation Revenue
2010	3,275	12	$ 115	6
2011	2,570	10	198	10
2012	3,852	15	212	10
2013	5,359	20	506	25
2014	1,211	5	118	6
2015 and beyond	10,337	38	867	43
Total	26,604	100	$ 2,016	100

Summary of Operational and Financial Performance

In 2009, we continued to deliver strong operational and financial performance across all pipelines benefitting from several expansion projects placed in service. These projects included the Carthage Expansion in May, Totem Gas Storage in June, the WIC Piceance Lateral expansion in September, and the Concord Lateral Expansion in October. We continue to make significant progress on our remaining backlog of expansion projects. In 2009, EPB issued additional public common units and used the proceeds primarily to acquire additional interests in CIG. At December 31, 2009, our ownership interest in EPB consisted of a two percent general partner interest and a 65 percent limited partner interest.

During 2010, we plan to spend $2.9 billion in capital on our pipeline business, including $2.5 billion on our backlog of expansion projects. Our most significant projects are listed below grouped by anticipated in-service dates.

Project	Anticipated In-Service Dates	Total Estimated Project Costs (In millions)	Cumulative Project Spend as of December 31, 2009 (In millions)	FERC Approved
2010:				
Elba Expansion III and Elba Express (Phase A)	March/August 2010(2)	$ 903	$ 812	Yes
CIG Raton 2010 Expansion	December 2010	146	42	No(1)
2011 and Beyond:				
WIC System Expansion(3)	First Quarter of 2011	71	11	No(1)
Ruby Pipeline(4)(5)	First Quarter of 2011	2,964	732	No(1)
FGT Phase VIII Expansion (50%)(4)(6)	April 2011	1,202	372	Yes
Gulf LNG Clean Energy (50%)(6)(7)	October 2011	808	563	Yes
TGP 300 Line Expansion	November 2011	642	100	No(1)
	2011-2012	421	21	Yes

South System III and Southeast Supply Header Phase II[1]				
TGP Northeast Upgrade Project	November 2013	416		No
Elba Expansion III and Elba Express (Phase B)	January 2014	261	5	Yes

(1) An application has been filed with the FERC for this project.

(2) Elba Expansion III vaporization and Elba Express in-service dates are March 2010 and Elba Expansion III storage in-service date is August 2010.

(3) This expansion consists of two projects.

(4) These projects have substantial contractual commitments with customers but are not fully contracted.

(5) Amount includes 100 percent of our Ruby pipeline project expenditures. As of December 31, 2009, we have received $362 million and anticipate obtaining approximately $700 million of funding in total from our equity partner on this project.

(6) Amounts represent our share of the estimated costs for these unconsolidated affiliates.

(7) Amount includes approximately $295 million that we paid to acquire a 50 percent interest in this project.

Listed below is additional information related to our significant backlog projects:

Elba Expansion III/ Elba Express/ Cypress Phase III. During the second quarter of 2009, BG LNG Services LLC (BG) and SNG, Elba Express and Southern LNG, Inc. entered into agreements to delay the in-service date of the Elba Expansion III Phase B project at BG s option, to as late as December 31, 2014, or, in the event certain conditions are unable to be met by BG, to terminate the Elba Expansion III Phase B project. In exchange for this delay/termination option, BG has committed to subscribe to certain firm Phase B capacity on our Elba Express pipeline and to provide certain rate considerations on an existing transportation contract on our SNG Pipeline. In addition, BG has given up its right to proceed with Phase III of the Cypress Expansion Project on SNG. Phase A of both the Elba Expansion III vaporization facilities and the Elba Express project are expected to commence commercial operations in March 2010.

WIC Expansion. WIC expanded the scope of this project to add a second compressor unit on the Kanda Lateral due to increased shipper commitments. This portion of the project will add a 12,400 horsepower compressor station on the Kanda Lateral which will increase the capacity on this lateral to 595 MDth/d. WIC also plans to install three miles of pipeline and reconfigure one compressor at its Wamsutter station which will provide 155 MDth/d natural gas deliveries from the WIC Mainline into a third party pipeline and onto the Opal Hub and the proposed Ruby pipeline.

Ruby Pipeline Project. We expect that the Ruby pipeline project will consist of approximately 680 miles of 42 pipeline and multiple compressor stations with total horsepower of approximately 157,000; however, final sizing will be based on market support. In September 2009, we received a Preliminary Determination from the FERC on non-environmental issues related to this project. In January 2010, the FERC issued a final Environmental Impact Statement (EIS) related to our Ruby project. Subject to FERC and other approvals, the project is expected to commence construction in the first half of 2010 and is anticipated to be placed in service during the first quarter of 2011.

FGT Phase VIII Project. In September 2009, the FERC issued a final EIS. We also received the Pipeline and Hazardous Materials Safety Administration special permit from the Department of Transportation in order to operate the pipeline at higher operating pressures. In November 2009, the FERC approved this project.

Gulf LNG. 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 LNG terminal in Pascagoula, Mississippi with a designed sendout capacity of 1.5 bcf/d that is expected to be placed in service in October 2011.

TGP 300 Line Expansion. All of the firm transportation capacity resulting from this project in the northeast U.S. market area is fully subscribed with one shipper based on a precedent agreement which was executed in the third quarter of 2009. An environmental assessment is expected to be issued by the FERC in the first quarter of 2010.

South System II/ Southeast Supply Header. The South System II expansion project will expand SNG s pipeline system in Mississippi, Alabama and Georgia by adding approximately 81 miles of pipeline looping and replacement on SNG s south system and 17,310 of horsepower compression to serve an existing power generation facility in the Atlanta, Georgia area. This project will be completed in three phases with each phase expected to add an additional 122 MMcf/d of capacity.

The Southeast Supply Header is expected to provide access through pipeline interconnects to several supply basins, including the Barnett Shale, Bossier Sands, Arkoma and Fayetteville Shale basins and is expected to provide SNG with an additional 350 MMcf/d of supply capacity.

TGP Northeast Upgrade Project. In February 2010, TGP entered into precedent agreements with two shippers to provide 636,000 MMBtu/d of additional firm transportation service from receipt points in the Marcellus Shale basin to an interconnect in New Jersey. In order to accommodate the additional service, we will pursue Northeast Upgrade project which includes approximately 37 miles of 30 pipeline looping and approximately 20,600 horsepower of additional compression. The expected cost for this project is $416 million and construction is anticipated to be placed in service by November 2013.

Successful execution on our committed pipeline backlog will continue to require effective project management. In addition to securing a partner for the Ruby pipeline project in 2009, we have significantly mitigated the risk associated with our remaining backlog by subscribing approximately 90 percent of the capacity of our aggregate backlog under contract terms of 10 to 30 years primarily with investment-grade customers and purchasing or committing to purchase steel at fixed prices for all of our largest projects as well as contracting a significant portion of the construction costs.

In addition to our current backlog of contracted organic growth projects, we have other potential projects that are in various phases of commercial development. Many of these projects involve expansion capacity to serve increased natural gas-fired generation loads, as well as new supply projects. Most of our potential expansion projects would have in-service dates for 2014 and beyond. If we are successful in contracting for these new projects, the capital requirements could be substantial and would be incremental to our current projects. Although we pursue the development of these and other potential projects from time to time, there can be no assurance that we will be successful in negotiating the definitive binding contracts necessary for such projects.

Potential Power Plant Loads. Similar to SNG s South System III project, we are pursuing various expansion projects particularly in the southeastern portion of the United States (U.S.) to serve increased natural gas-fired generation loads. In addition, along the Front Range of CIG s system, utilities have various projects under development that involve constructing new natural gas-fired generation in part to provide backup capacity required when renewable generation is not available during certain daily or seasonal periods.

Operating Results

	2009	2008	2007
	(In millions, except volumes)		
Operating revenues	$ 2,767	$ 2,684	$ 2,494
Operating expenses	(1,486)	(1,532)	(1,383)
Operating income	1,281	1,152	1,111
Other income, net	200	156	157
EBIT before noncontrolling interests	1,481	1,308	1,268
Net income attributable to noncontrolling interests	(65)	(35)	(3)
EBIT(3)	$ 1,416	$ 1,273	$ 1,265
Throughput volumes (BBtu/d)(1)			
TGP	4,614	4,864	4,880
El Paso Natural Gas (EPNG) and Mojave Pipeline (MPC)	3,982	4,422	4,216
CIG, WIC and Cheyenne Plains Gas Pipeline (CPG)	5,550	5,376	4,906
SNG	2,322	2,339	2,345
Other	50	50	50
Equity investments and other(2)	1,820	1,763	1,734
Total throughput	18,338	18,814	18,131

(1) Volumes exclude intrasegment activities.

(2) Represents our proportional share of unconsolidated affiliates.

(3) 2007 EBIT represents EBIT from continuing operations.

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Below is a discussion that details the impact on EBIT of significant events in 2009 compared with 2008 and 2008 as compared with 2007. We have also provided an outlook on events that may affect our operations in the future.

	2009 to 2008 Variance				2008 to 2007 Variance			
	Revenue	Expense	Other	Total	Revenue	Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 103	$ (25)	$ 49	$ 127	$ 74	$ (26)	$ 19	$ 67
Reservation and usage revenues	23			23	67			67
Gas not used in operations and revaluations	2	30		32	33	(13)		20
Bankruptcy proceeds	(48)	(1)		(49)	27	1		28
Operating and general and administrative expense		4		4		(62)		(62)
Gain/loss on long-lived assets		42		42		(31)	1	(30)
Hurricanes	10	13		23	(10)	(14)		(24)
Equity earnings from Citrus			2	2			(17)	(17)
Net income attributable to noncontrolling interests			(30)	(30)			(32)	(32)
Other[1]	(7)	(17)	(7)	(31)	(1)	(4)	(4)	(9)
Total impact on EBIT	$ 83	$ 46	$ 14	$ 143	$ 190	$ (149)	$ (33)	$ 8

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

Expansions. During 2009 and 2008, our reservation revenues and throughput volumes increased due to the projects placed in service. During 2009 and 2008, we placed the Carthage expansion project, the Totem Gas Storage facility, the Concord Lateral expansion, the WIC Piceance Lateral expansion, the WIC Kanda Lateral project, Phase II of the Cypress project, the Cheyenne Plains compression expansion project, Phase I of the Southeast Supply Header project, the Medicine Bow expansion and the High Plains Pipeline projects in service.

Reservation and Usage Revenues. During the year ended December 31, 2009 compared with 2008, our reservation and usage revenues were also impacted by:

- increased revenues for the mainline and lateral capacity on our Rocky Mountain region systems primarily due to new contracts and restructured contract terms;
- additional capacity sales of approximately $8 million primarily from the Marcellus Basin in the northeast market area of our TGP system;

increased reservation and other services revenues of approximately $24 million primarily on our SNG system due to higher tariff rates effective September 1, 2009 pursuant to SNG s rate case settlement further discussed below;

higher reservation charges of approximately $11 million for capacity on our EPNG system resulting from increased contracted capacity to primary delivery points in California and an increase in EPNG s tariff rates effective January 1, 2009, subject to refund; and

unfavorable usage revenue of approximately $20 million due to decreased activity under various interruptible services and lower demand at the southeast interconnects resulting from increased competition on our TGP system.

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For the year ended December 31, 2009, our throughput volumes on the TGP and EPNG systems decreased compared with 2008. This was due, in part, to general weakness in natural gas demand in the United States, including in the northeast and southwest. Although fluctuations in throughput on our pipeline systems have a limited effect on our short-term results since a material portion of our revenues are derived from firm reservation charges, it can be an indication of the risks we may face when seeking to recontract or renew any of our existing firm transportation contracts. Continuing negative economic impacts on demand, as well as adverse shifting of sources of supply, could negatively impact basis differentials and our ability to renew firm transportation contracts that are expiring on our system or our ability to renew such contracts at current rates. If we determine there is a significant change in our costs or billing determinants on any of our pipeline systems, we will have the option to file rate cases on certain of our pipelines with the FERC to recover our prudently incurred costs.

For the year ended December 31, 2008 compared with 2007, the increase in our reservation and usage revenues was primarily due to:

- approximately $22 million related to increased demand for off-system and mainline capacity on our Rocky Mountain region systems primarily due to lower natural gas prices in the Rocky Mountains as compared to other regions in the United States;

- approximately $15 million related to additional firm capacity sold in the northern and southern regions of our TGP system, partially offset by lower surcharges from certain firm customers on this system ;

- approximately $29 million related to increased reservation and usage revenues on our EPNG system due to higher amounts charged on recontracted capacity in Arizona and California; and

- approximately $1 million related to additional interruptible and firm commodity services provided in several of our pipeline systems.

Gas Not Used in Operations and Revaluations. During the year ended December 31, 2009, our overall EBIT was $32 million favorable when compared with 2008, primarily due to retained fuel volumes in excess of fuel used in operations, higher realized prices on operational sales, lower electric compression utilization, and lower index prices related to fuel imbalance revaluations, settlement and other gas balance related items.

In addition, during 2008, CIG and WIC recorded cost and revenue tracker adjustments associated with the implementation of fuel and related gas cost recovery mechanisms, which the FERC approved subject to the outcome of technical conferences. The implementation of these mechanisms was protested by a limited number of shippers. On July 31, 2009 and October 1, 2009, the FERC issued orders to CIG and WIC, respectively, directing them to remove the cost and revenue components from their fuel recovery mechanisms. Additionally, on October 1, 2009, EPNG received an order from the FERC directing EPNG to remove the cost and revenue component of its fuel recovery mechanism. EPNG s compliance filing to remove the cost and revenue component was approved in the fourth quarter of 2009. Our future earnings may be impacted positively or negatively depending on fluctuations in gas prices related to the revaluation of EPNG s under or over recoveries, imbalances and system encroachments. EPNG s tariff continues to provide that the difference between the quantity of fuel retained and fuel used in operations and lost and unaccounted for will be flowed through or charged to shippers. We continue to explore options to minimize the price volatility associated with these operational pipeline activities.

During the year ended December 31, 2008 compared with the same period in 2007, our EBIT was favorably impacted by $20 million due to higher volumes of gas not used in our TGP operations.

Bankruptcy Proceeds. During 2008, our revenue increased by $39 million related to Calpine Corporation s (Calpine s) rejection of its transportation contracts with us primarily associated with distributions received under Calpine s approved plan of reorganization. During 2008 and 2007, we recorded income of approximately $10 million and $5 million, net of amounts potentially owed to certain customers, related to amounts recovered from the Enron bankruptcy settlement. In 2007, we received $10 million to settle our bankruptcy claim against USGen New England, Inc.

Operating and General and Administrative Expenses. For the year ended December 31, 2009, our operating and general and administrative expenses were lower than in 2008 primarily due to $18 million of decreased field repair and maintenance expense on several of our pipeline systems. Partially offsetting these cost reductions were severance costs of approximately $14 million. During the year ended December 31, 2008, our operating and general and administrative expenses were higher than in 2007 primarily due to increased labor costs of approximately $43 million to support our growth and customer activities and approximately $29 million in additional maintenance work required on several of our pipeline systems.

Gain/Loss on Long-Lived Assets. During 2009, we recorded a gain of $8 million related to the sale of CIG s Natural Buttes compressor station and gas processing plant. During 2008, we recorded impairments of $41 million, including an impairment related to our Essex-Middlesex Lateral project due to a prolonged permitting process and an impairment of our EPNG Arizona gas storage projects that we are no longer developing due to declining real estate values. During 2007, we recorded (i) a $10 million impairment of certain pipeline assets originally purchased to repair certain offshore hurricane damage following a decision not to use these assets, (ii) a loss of approximately $9 million on EPNG s East Valley Line Lateral pursuant to a FERC determination on the accounting treatment for the pending sale of certain transmission facilities and (iii) a $7 million pre-tax gain on the sale of a pipeline lateral.

Hurricanes. During 2008, we incurred damage to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Ike and Gustav. Our EBIT was unfavorably impacted by $8 million in 2009 due to repair costs and $31 million in 2008 related to these hurricanes due to gas loss from various damaged pipelines, lower volume of gas not used in operations, and repair costs that did not exceed self-retention levels.

Equity Earnings from Citrus. In 2008, equity earnings on our Citrus investment decreased as compared to 2007 primarily due to Citrus s favorable settlement in 2007 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 and Citrus sale of a receivable in 2007 for approximately $3 million related to the bankruptcy of Enron North America.

Net Income Attributable to Noncontrolling Interests. Our net income attributable to noncontrolling interests increased during 2009 and 2008 due to (i) the additional public common units issued by our majority-owned MLP in July 2009 and (ii) our contribution to our MLP of additional interests in CIG (18 percent in July 2009 and 20 percent in September 2008) and SNG (15 percent in September 2008). As of December 31, 2009, our MLP owned 58 percent of CIG, 25 percent of SNG and 100 percent of WIC and we owned 67 percent of the MLP.

Other Regulatory Matters. Our pipeline systems periodically file for changes in their rates, which are subject to the approval by 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, while certain of our pipelines are expected to continue operating under their existing rates, other pipelines have projected upcoming rate actions with anticipated effective dates from 2011 through 2013.

In January 2010, the FERC approved SNG s settlement in which SNG (i) increased its base tariff rates, (ii) implemented a volume tracker for gas used in operations, (iii) agreed to file its next general rate case to be effective after August 31, 2012 but no later than September 1, 2013, and (iv) extended the vast majority of SNG s firm transportation contracts until August 31, 2013.

In June 2008, EPNG filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposed an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates effective January 1, 2009, subject to refund and the outcome of a hearing and a technical conference. The FERC issued an order in December 2008 that generally accepted most of EPNG s proposals in the technical conference proceeding. The FERC has appointed an administrative law judge to preside over a hearing if EPNG is unable to reach a negotiated settlement with its customers on the remaining issues. Settlement negotiations are continuing; however, the hearing has been postponed until May 2010. The outcome of the settlement discussions and the hearing is not currently determinable.

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 at 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 strategy focuses on building and applying competencies in assets with repeatable programs, executing to improve capital and expense efficiency, and maximizing returns by adding assets and inventory that match our competencies and divesting assets that do not. During 2009, in the U.S., we shifted our focus to more unconventional resource plays including the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont-Bluebell-Cedar Rim Field fractured tight sands in Utah.

Our domestic natural gas and oil reserve portfolio blends lower decline rate, typically longer lived assets in our Central and Western divisions, with steeper decline rate, shorter lived assets in our Gulf Coast division. Approximately 79 percent of our 2009 capital was spent on domestic projects. Internationally, our portfolio consists of producing fields along with several exploration and development projects in offshore Brazil and exploration projects in Egypt. Our 2009 international capital, primarily in Brazil, constituted approximately 21 percent of our total capital program. Success of our international programs in Brazil and Egypt will require effective project management, strong partner relations and obtaining approvals from regulatory agencies.

During 2009, the challenging commodity price environment resulted in ceiling test charges totaling $2.1 billion. Coupled with unprecedented challenges in the credit markets, we also reduced our capital spending during 2009.

We continue to evaluate acquisition and growth opportunities that are focused on our core competencies and areas of competitive advantage. Strategic acquisitions, like the one we completed in December 2009 of natural gas and oil properties in the Altamont-Bluebell-Cedar Rim Field in Utah, can support our corporate objectives, providing us greater opportunities to achieve our long term performance goals by leveraging operational expertise already possessed in key operating areas, balancing our exposure to regions, basins and commodities, achieving risk-adjusted returns competitive with those available within our existing inventory, and increasing our reserves by supplementing our current drilling inventory.

In addition to effectively executing on our strategy, our profitability and performance is impacted by (i) changes in commodity prices, (ii) industry-wide changes in the cost of drilling and oilfield services, 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 maintain derivative contracts to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Year Ended December 31, 2009

Production. Our average daily production for the year was 763 MMcfe/d, including 72 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our 2009 production by division (MMcfe/d):

	2009	2008	2007
United States			
Central	257	238	227
Western	154	154	147
Gulf Coast	268	339	404
International			
Brazil	12	11	14
Total consolidated	691	742	792
Four Star	72	74	70
Total combined	763	816	862

Central division Our 2009 Central division production volumes continued to increase as a result of our successful Arklatex drilling programs including the Haynesville Shale. In the Haynesville Shale, we drilled 17 wells during the year and had average net production of approximately 36 MMcfe/d. At December 31, 2009, we had 20 operated wells producing at a rate of approximately 110 MMcfe/d.

Western division Our 2009 Western division production volumes were flat as compared to 2008 primarily due to the successful drilling programs in the Altamont-Bluebell-Cedar Rim Field offset by natural declines in the Rockies.

Gulf Coast division Our 2009 Gulf Coast division production volumes decreased primarily due to sales of assets in 2008 and early 2009. In this division, our 2009 focus was on increasing our Eagle Ford Shale acreage, where we hold approximately 132,000 net acres as of December 31, 2009 and drilled our first well which was successful.

Brazil In Brazil, our 2009 production volumes were up slightly from 2008. Production from natural declines in our Pescada-Arabiana Fields was more than offset by new production from our Camarupim Field, where we began production in the fourth quarter of 2009.

2009 Drilling Results

Central. We achieved a 99 percent success rate on 139 gross wells drilled.

Western. We achieved a 100 percent success rate on seven gross wells drilled.

Gulf Coast. We achieved an 80 percent success rate on 30 gross wells drilled.

Brazil. We achieved a 75 percent success rate on four gross wells drilled.

Egypt. Hydrocarbons were found in two of five or 40 percent of the gross exploratory wells we drilled or participated in drilling.

For a further discussion of our activities in Brazil and Egypt, see Part I, Item 1, Business, Exploration and Production Segment, International.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil production volumes. Cash operating costs is a non-GAAP measure calculated on a per Mcfe basis and includes total operating expenses less depreciation, depletion and amortization expense, ceiling test and other impairment charges, transportation costs and cost of products. Cash operating costs per unit is a valuable measure of operating performance and efficiency for the exploration and production segment.

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During the year ended December 31, 2009, cash operating costs per unit decreased to $1.82/Mcfe as compared to $1.97/Mcfe in 2008. The decrease in 2009 is primarily due to lower lease operating expenses and production taxes partially offset by lower production volumes in 2009 versus 2008.

Reserve Replacement Ratio/Reserve Replacement Costs. 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 lower costs than our competition. We calculate these metrics as follows:

Reserve replacement ratio	Sum of reserve additions[1] [2]
	Actual production for the corresponding period
Reserve replacement costs/Mcfe	Total oil and gas capital costs[3]
	Sum of reserve additions [1] [2]

(1) Reserve additions include proved reserves and reflect reserve revisions for prices and performance, 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. We present these metrics separately, both including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of our drilling program exclusive of economic factors (such as price) outside of our control. All amounts are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

(2) The proved reserves used in the calculation of reserve replacement ratio and reserve replacement costs in 2009 were determined based on the SEC s final rule on Modernization of Oil and Gas Reporting (Final Rule) effective December 31, 2009. The Final Rule, among other things, revised the definitions of proved reserves and required us to use a first day 12-month average price in determining estimated proved reserves.

(3) 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.

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 developing 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, 2009, proved developed reserves represent approximately 67 percent of our 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.

The table below shows our reserve replacement costs and reserve replacement ratio for our domestic and worldwide operations, including and excluding the effect of price revisions on reserves for each of the years ended December 31:

	Including Price Revisions			Excluding Price Revisions		
	2009	2008 ($/Mcfe)	2007	2009	2008 ($/Mcfe)	2007
Domestic						
Reserve replacement costs, including acquisitions	$1.84	$ 6.68	$3.26	$1.57	$2.87	$3.46
Reserve replacement costs, excluding acquisitions	1.91	7.01	3.22	1.59	2.87	3.65
Worldwide						
Reserve replacement costs, including acquisitions	$2.04	$36.00	$3.55	$1.76	$3.25	$3.77
Reserve replacement costs, excluding acquisitions	2.13	56.05	3.79	1.81	3.26	4.29
		(% of Production)			(% of Production)	
Domestic						
Reserve replacement ratio, including acquisitions	188%	84%	255%	220%	195%	240%
Reserve replacement ratio, excluding acquisitions	162%	77%	129%	195%	188%	114%
Worldwide						
Reserve replacement ratio, including acquisitions	212%	17%	252%	245%	192%	237%
Reserve replacement ratio, excluding acquisitions	187%	11%	129%	220%	186%	114%

We typically cite reserve replacement costs in the context of a multi-year trend, in recognition of its limitation as a single year measure, and also to demonstrate consistency and stability, which are essential to our business model. The table below shows our reserve replacement costs for our domestic and worldwide operations for the three years ended December 31, 2009.

	Including Price Revisions	Excluding Price Revisions
	Three Years Ending December 31, 2009 ($/Mcfe)	
Domestic		
Reserve replacement costs, including acquisitions	$ 3.33	$ 2.70
Reserve replacement costs, excluding acquisitions	3.48	2.59
Worldwide		
Reserve replacement costs, including acquisitions	$ 4.10	$ 2.94
Reserve replacement costs, excluding acquisitions	4.66	2.92

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

	2009	2008	2007

		(in millions)	
Total oil and gas capital costs, excluding acquisitions	$ 1,004	$ 1,648	$ 1,411
Acquisitions	87	51	1,178
Total oil and gas capital costs, including acquisitions[1]	$ 1,091	$ 1,699	$ 2,589

(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.

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Outlook for 2010

For 2010, we anticipate continued volatility in the commodity markets and the general economic climate. We will exercise flexibility in allocating capital in response to changing conditions.

We expect the following on a worldwide basis:

- Capital expenditures, excluding acquisitions, of approximately $1.1 billion. Of this total, we expect to spend approximately $0.9 billion on our domestic program and approximately $0.2 billion in Brazil and Egypt.

- Average daily production volumes for the year of approximately 740 MMcfe/d to 780 MMcfe/d, which includes approximately 60 MMcfe/d to 65 MMcfe/d from Four Star. Production volumes from our Brazil operations are expected to increase to between 45 MMcfe/d and 55 MMcfe/d in 2010.

- Average cash operating costs between $1.85/Mcfe and $2.15/Mcfe for the year; and

- Depreciation, depletion and amortization rate between $1.65/Mcfe and $1.85/Mcfe.

Price Risk Management Activities

We enter into derivative contracts on our natural gas and oil production to stabilize cash flows, 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 we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge the entirety of our price risk, this strategy only partially reduces our commodity price exposure. Our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

During 2009, we entered into option and basis swap contracts on our 2010 and 2011 natural gas production and swaps on our 2010 oil production and paid $173 million in premiums to enter into these contracts.

The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of December 31, 2009.

	Fixed Price Swaps[(1)]		Floors[(1)]		Ceilings[(1)]		Basis Swaps[(1)(2)]							
							Texas Gulf Coast		Western Raton		Western Rockies		Central Mid-Continent	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
Natural Gas														
2010	52	$ 6.19	123	$ 6.50	60	$ 8.14	48	$(0.40)	20	$(0.78)	9	$(1.93)	9	$(0.74)
2011	16	$ 5.99	120	$ 6.00	120	$ 9.00	33	$(0.13)	7	$(0.29)				
2012	2	$ 3.93												
Oil														
2010	2,373	$74.63	1,643	$75.00	1,643	$91.33								

(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.

Internationally, production from the Camarupim Field in Brazil is sold at a price that is adjusted quarterly based on a basket of fuel oil prices. In addition to the amounts included in the table above, as of December 31, 2009, we have fuel oil swaps that effectively lock in a price of approximately $4.00 per MMBtu on approximately 8 TBtu of projected Brazilian natural gas production in 2010.

During the first two months of 2010, we entered into 635 MBbls of fixed price swaps on our anticipated 2010 oil production at an average price of $85.18 per barrel. In addition, we entered into collars on 2,008 MBbls of our anticipated 2011 oil production with a floor price of $80 per barrel and an average ceiling price of $95.56 per barrel, and basis swaps at an average price of $0.21 per MMBtu on 15 TBtu of anticipated 2011 natural gas production.

Operating Results and Variance Analysis

The information below provides the financial results and an analysis of significant variances in these results during the periods ended December 31:

	2009	2008	2007
		(In millions)	
Physical sales:			
Natural gas	$ 830	$ 1,960	$ 1,582
Oil, condensate and NGL	267	541	499
Total physical sales	1,097	2,501	2,081
Realized and unrealized gains on financial derivatives(1)	687	196	184
Other revenues	44	65	35
Total operating revenues	1,828	2,762	2,300
Operating Expenses:			
Cost of products	31	38	20
Transportation costs	66	79	72
Production costs	252	363	344
Depreciation, depletion and amortization	440	799	780
General and administrative expenses	195	160	185
Ceiling test charges	2,123	2,669	
Impairment of inventory and other assets	25		
Other	13	12	13
Total operating expenses	3,145	4,120	1,414
Operating income (loss)	(1,317)	(1,358)	886
Other income (expense)(2)	(32)	(90)	23
EBIT	$ (1,349)	$ (1,448)	$ 909

(1) Includes $406 million, $(88) million and $176 million for the years ended December 31, 2009, 2008 and 2007, reclassified from accumulated other comprehensive income associated with accounting hedges.

(2) Other income includes equity earnings from Four Star, our unconsolidated affiliate, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets. In 2008, other income also includes a $125 million impairment charge related to our equity interest in Four Star.

	2009	Percent Variance	2008	Percent Variance	2007
Volumes:					
Natural gas					
Consolidated volumes (MMcf)	218,544	(6)%	232,703	(4)%	242,316
Unconsolidated affiliate volumes (MMcf)	19,557	(5)%	20,576	6%	19,380
Oil, condensate and NGL					
Consolidated volumes (MBbls)	5,648	(13)%	6,495	(17)%	7,821
Unconsolidated affiliate volumes (MBbls)	1,097	4%	1,054	4%	1,015
Equivalent volumes					
Consolidated MMcfe	252,432	(7)%	271,673	(6)%	289,242
Unconsolidated affiliate MMcfe	26,139	(3)%	26,899	6%	25,470
Total combined MMcfe	278,571	(7)%	298,572	(5)%	314,712
Consolidated MMcfe/d	691	(7)%	742	(6)%	792
Unconsolidated affiliate MMcfe/d	72	(3)%	74	6%	70
Total Combined MMcfe/d	763	(6)%	816	(5)%	862
Consolidated prices and costs per unit:					
Natural gas					
Average realized price on physical sales ($/Mcf)	$ 3.80	(55)%	$ 8.43	29%	$ 6.53
Average realized prices, including financial derivative settlements ($/Mcf)(1)	$ 7.62	(7)%	$ 8.18	14%	$ 7.18
Average transportation costs ($/Mcf)	$ 0.28	(10)%	$ 0.31	15%	$ 0.27
Oil, condensate and NGL					
Average realized price on physical sales ($/Bbl)	$ 47.27	(43)%	$ 83.21	31%	$ 63.71
Average realized price, including financial derivative settlements ($/Bbl)(1)	$ 78.38	1%	$ 77.78	25%	$ 62.19
Average transportation costs ($/Bbl)	$ 0.77	(20)%	$ 0.96	19%	$ 0.81
Production costs and other cash operating costs ($/Mcfe)					
Average lease operating expenses	$ 0.78	(13)%	$ 0.90	2%	$ 0.88
Average production taxes(2)	0.22	(50)%	0.44	42%	0.31
Total production costs	$ 1.00	(25)%	$ 1.34	13%	$ 1.19
Average general and administrative expenses	$ 0.77	31%	$ 0.59	(8)%	$ 0.64
Average taxes, other than production and income taxes	$ 0.05	25%	$ 0.04	(20)%	$ 0.05

Total cash operating costs	$	1.82	(8)%	$	1.97	5%	$	1.88
Depreciation, depletion and amortization ($/Mcfe)(3)	$	1.74	(41)%	$	2.94	9%	$	2.70

(1) Premiums related to natural gas derivatives settled during the year ended December 31, 2008 were $21 million. Had we included these premiums in our natural gas average realized prices in 2008, our realized price, including financial derivative settlements, would have decreased by $0.09/Mcf for the year ended December 31, 2008. We had no premiums related to natural gas derivatives settled during the years ended December 31, 2009 and 2007, or related to oil derivatives settled during the years ended December 31, 2009, 2008 and 2007.

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

(3) Includes $0.06 per Mcfe, $0.05 per Mcfe and $0.07 per Mcfe for the years ended December 31, 2009, 2008 and 2007 related to accretion expense on asset retirement obligations.

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Our EBIT for 2009 increased $99 million as compared to 2008. The table below shows the significant variances in our financial results in 2009 as compared to 2008:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Lower realized prices in 2009	$ (1,011)	$	$	$ (1,011)
Lower volumes in 2009	(119)			(119)
Oil, condensate and NGL				
Lower realized prices in 2009	(203)			(203)
Lower volumes in 2009	(71)			(71)
Realized and unrealized gains on financial derivatives	491			491
Other revenues	(21)			(21)
Depreciation, depletion and amortization expense				
Lower depletion rate in 2009		305		305
Lower production volumes in 2009		54		54
Production costs				
Lower lease operating expenses in 2009		46		46
Lower production taxes in 2009		65		65
General and administrative expenses		(35)		(35)
Ceiling test charges		546		546
Impairment of inventory and other assets		(25)		(25)
Earnings from unconsolidated affiliate			63	63
Other		19	(5)	14
Total variances	$ (934)	$ 975	$ 58	$ 99

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the year ended December 31, 2009, natural gas, oil, condensate and NGL revenues decreased as compared to 2008 due to lower commodity prices and lower production volumes.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2009, we recognized net gains of $687 million compared to net gains of $196 million during 2008 due to lower natural gas and oil prices in 2009 relative to the commodity prices contained in our derivative contracts.

Depreciation, depletion and amortization expense. During 2009, our depreciation, depletion and amortization expense decreased as a result of a lower depletion rate and lower production volumes. The lower depletion rate is primarily a result of the impact of the ceiling test charges recorded in December 2008 and March 2009.

Production costs. Our production costs decreased during 2009 as compared to the same periods in 2008 primarily due to lower production taxes as a result of lower natural gas and oil revenues and lower lease operating expenses from cost declines in the lower commodity price environment.

General and administrative expenses. Our general and administrative expenses increased during 2009 as compared to the same periods in 2008 primarily due to the reversal of a $20 million accrual in 2008 as a result of a favorable ruling on a legal matter and higher severance costs of approximately $7 million due to reorganizations in 2009.

Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the fourth quarter of 2008 and the first quarter of 2009, we recorded total non-cash ceiling test charges of $2.7 billion and $2.1 billion. The calculation of these charges was based on spot commodity prices at the end of each period. In calculating our fourth quarter 2008 ceiling test charges, capitalized costs exceeded the ceiling limit by $2.2 billion for our domestic full cost pool and $0.5 billion for our Brazilian full cost pool. In the first quarter of 2009, due to low natural gas and oil prices, we experienced a downward price-related reserve revision of approximately 400 Bcfe (primarily in our Arklatex, Raton and Mid-Continent areas) and recorded non-cash ceiling test charges of approximately $2.0 billion in our domestic full cost pool and $28 million in our Brazilian full cost pool.

During the fourth quarter of 2009, primarily due to proved reserve additions, we did not record ceiling test charges in our domestic full cost pool; however, we recorded a $30 million ceiling test charge in our Brazilian full cost pool as a result of lower commodity prices and a downward performance-related reserve revision in our Pescada-Arabaiana Fields.

As a result of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we were required to use a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) when performing the ceiling tests. In calculating our ceiling test charges, we are also required to hold prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. For more information on the first day 12-month average price used to calculate the ceiling test, see Supplemental Natural Gas and Oil Operations.

During 2009 and 2008, we also recorded non-cash ceiling test charges in our Egyptian full cost pool of $34 million and $9 million. These charges were primarily as a result of dry hole costs on unsuccessful wells drilled during these years.

Impairment of inventory and other assets. In 2009, we recorded a $16 million non-cash charge to reflect the current market price we expect to receive upon the sale of certain casing and tubular goods inventory (materials and supplies), which prior to the third quarter, we intended to use in our capital programs. Based on changes to our capital program we decided that we would sell this inventory and use the proceeds to purchase inventory related to our current capital projects. We also recorded a $9 million non-cash charge as a result of our decision to close our Bluebell processing plant in 2010.

Other. Our equity earnings from Four Star increased by $63 million during the year ended December 31, 2009 as compared to 2008 primarily due to an impairment of the carrying value of our investment of $125 million recorded in 2008, partially offset by the impact of lower commodity prices in 2009.

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Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Our EBIT for 2008 decreased $2,357 million as compared to 2007. The table below shows the significant variances in our financial results in 2008 as compared to 2007:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Higher realized prices in 2008	$ 441	$	$	$ 441
Lower volumes in 2008	(63)			(63)
Oil, condensate and NGL				
Higher realized prices in 2008	127			127
Lower volumes in 2008	(85)			(85)
Realized and unrealized gains on financial derivatives	12			12
Other revenues	30			30
Depreciation, depletion and amortization expense				
Higher depletion rate in 2008		(64)		(64)
Lower production volumes in 2008		45		45
Production costs				
Lower lease operating expenses in 2008		10		10
Higher production taxes in 2008		(29)		(29)
General and administrative expenses		25		25
Ceiling test charges		(2,669)		(2,669)
Earnings from unconsolidated affiliate			(104)	(104)
Other		(24)	(9)	(33)
Total variances	$ 462	$ (2,706)	$ (113)	$ (2,357)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During 2008, revenues increased as compared with 2007 due primarily to higher commodity prices. During the year ended December 31, 2008, we also benefited from an increase in production volumes in all of our domestic divisions compared to 2007 primarily as a result of successful drilling programs and our Peoples acquisition in the third quarter of 2007. Our Gulf Coast division production volumes decreased in 2008 versus 2007 primarily due to asset sales, production shut in as a result of Hurricanes Ike and Gustav and natural production declines.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2008, we recognized net gains of $196 million compared to net gains of $184 million during 2007 due to natural gas and oil prices in 2008 relative to the commodity prices contained in our derivative contracts.

Depreciation, depletion and amortization expense. During 2008, our depletion rate increased as compared to the same period in 2007 as a result of the Peoples and Zapata County, Texas acquisitions in 2007 and higher finding and development costs.

Production costs. Our production costs increased during 2008 as compared to 2007 primarily due to higher production taxes which increased due to higher natural gas and oil revenues. The increase in production taxes was partially offset by a reduction in lease operating expenses for the year ended December 31, 2008, primarily as a result of the impact of divested properties.

General and administrative expenses. Our general and administrative expenses decreased during 2008 as compared to the same periods in 2007 primarily due to the reversal of a $20 million accrual as a result of a favorable ruling on a legal matter.

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Ceiling test charges. In the fourth quarter of 2008, we recorded non-cash full cost ceiling test charges of $2.7 billion. Capitalized costs exceeded the ceiling limit by $2.2 billion for our domestic full cost pool and $0.5 billion for our Brazilian full cost pool. The calculation of these charges was based on the December 31, 2008 spot natural gas price of $5.71 per MMBtu and oil price of $44.60 per barrel, as required at that time. In calculating our ceiling test charges, we were required to hold prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period.

Prior to the fourth quarter of 2008, we included derivatives that were designated as accounting hedges in the determination of our future net revenues for purposes of calculating our ceiling tests. During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivative contracts related to our hedged natural gas and oil production volumes. We estimate that had we chosen not to de-designate these hedges, our ceiling test charges as of December 31, 2008 would have been lower by approximately $400 million.

Other. Our equity earnings from Four Star in 2008 decreased as compared to 2007 due primarily to a $125 million impairment of the carrying value of our investment based on a decline in its fair value as a result of lower forecasted commodity prices.

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 El Paso s overall price risk. In addition, we continue to manage and liquidate remaining legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. All of our remaining contracts are subject to counterparty credit and non-performance risks while our remaining mark-to-market contracts are also subject to interest rate exposure.

Legacy power contracts. The primary exposure remaining in the Marketing segment relates to mark-to-market power contracts that extend through April 2016. The exposure relates to volatility in locational power prices within the Pennsylvania-New Jersey-Maryland (PJM region).

Legacy transportation-related contracts. The impact of these accrual-based contracts is based on our ability to use or remarket the contracted pipeline capacity. As of December 31, 2009, these contracts require us to pay demand charges of $47 million in 2010 and an average of $41 million between 2011 and 2014. Additionally, in the fourth quarter of 2009, we entered into an agreement associated with the Ruby pipeline project that commences in 2016 and continues through 2021.

Legacy natural gas contracts. As of December 31, 2009, we have long term gas supply contracts that obligate us to deliver natural gas to specified power plants. The accounting on these contracts is a combination of mark-to-market and accrual-based. These are expected to have minimal future impact on this segment as we have substantially offset all of the fixed price exposure.

Operating Results

Overview. Our overall operating results and analysis by significant contract type for our Marketing segment during each of the three years ended December 31 are as follows:

	2009	2008	2007
		(In millions)	
Revenue by Significant Contract Type:			
Production-Related Natural Gas and Oil Derivative Contracts:			
Changes in fair value of options and swaps	$	$ (50)	$ (89)
Contracts Related to Legacy Trading Operations:			
Changes in fair value of power contracts	44	(46)	(77)
Natural gas transportation-related contracts:			
Demand charges	(35)	(35)	(98)
Settlements, net of termination payments	23	41	76
Changes in fair value of other natural gas derivative contracts	(3)	7	(31)
Total revenues	29	(83)	(219)
Operating expenses	(9)	(20)	(15)
Operating income (loss)	20	(103)	(234)
Other income, net		(1)	32
EBIT	$ 20	$ (104)	$ (202)

Our 2009 results were primarily driven by a $52 million mark-to-market gain related to the adoption of new accounting requirements for our derivative liabilities associated with non-cash collateral (e.g. letters of credit) partially offset by $27 million related to the impact of El Paso s credit standing on our derivative liabilities. Our 2008 and 2007 results were significantly impacted by mark-to-market losses on production-related natural gas and crude contracts that we held and managed during these years and losses of $46 million and $100 million in 2008 and 2007 due to changes in fair value of our PJM contracts. Additionally, in 2008 we signed a capacity purchase agreement that was executed to reduce our exposure to installed capacity prices which contributed to the losses recognized during 2007 and also recorded $19 million of revenue related to bankruptcy settlements. Additional items impacting our 2007 results were $23 million of other income from the sale of an investment and $28 million ($23 million of revenues and $5 million of other income) related to the settlement of outstanding California power price disputes.

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Power Segment

Overview. As of December 31, 2009, our remaining investment, guarantees and letters of credit related to projects in this segment totaled approximately $174 million, which consisted primarily of equity investments, notes and accounts receivable as follows:

Area		Amount (In millions)
South America		
Manaus & Rio Negro	$	52
Bolivia-to-Brazil Pipeline		117
Asia		5
Total	$	174

For the years ended December 31, 2009, 2008, and 2007, our Power segment generated an EBIT loss of $25 million, EBIT of $1 million, and an EBIT loss of $37 million. Our 2009 EBIT loss primarily relates to a loss on the sale of the Porto Velho notes receivable during 2009. Our 2007 EBIT loss was primarily due to impairments of $57 million on Porto Velho and $15 million on the Manaus and Rio Negro project offset by $30 million in EBIT generated on Porto Velho prior to the impairment and $9 million from our Manaus and Rio Negro project. Beginning in 2007, we ceased recognizing earnings from our Porto Velho project based on our inability to realize those earnings through the expected sales price of the investment. In 2007, our other Brazilian operations generated EBIT of $12 million.

In 2008, we transferred the ownership of our Manaus and Rio Negro power plants in Brazil to the plants power purchaser. While we no longer own the plants, we still have exposure relating to outstanding Brazilian reais-denominated receivables due from the power purchaser. We are also in the process of trying to resolve several outstanding claims related to these projects. In early 2009, we completed the sale of our investment in the Porto Velho power generation facility in Brazil to our partner in the project for cash and a notes receivable. In the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of $22 million. In 2009, we also sold our investment in the Argentina-to-Chile pipeline to our partners for approximately $32 million. Until the sale of our remaining international investments is completed, the Manaus and Rio Negro receivables are collected or matters further discussed in Item 8, Financial Statements and Supplementary Data, Note 19 are resolved, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in impairments of our remaining assets and investments.

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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:

	2009	2008	2007
		(In millions)	
Early extinguishment/exchange of debt	$	$	$ (291)
Foreign currency fluctuations on Euro-denominated debt	2		(8)
Change in litigation, environmental and other reserves	2	84	23
Gain on the sale of legacy assets		35	
Other	4	5	(7)
Total EBIT	$ 8	$ 124	$ (283)

Litigation, Environmental, and Other Reserves. During the year ended December 31, 2009, we recorded mark-to-market gains of $21 million associated with an indemnification in conjunction with the sale of a legacy ammonia facility based on fluctuations in ammonia prices. We also recorded $16 million in additional estimated environmental remediation costs related to a legacy non-operating chemical plant. During 2008, we recorded favorable adjustments related to resolving certain legacy litigation matters including $65 million related to our Case Corporation indemnification dispute (see Item 8, Financial Statements and Supplementary Data, Note 13) and $32 million related to the settlement of certain class action matters. Partially offsetting these 2008 settlements were approximately $46 million in mark-to-market losses based on significant increases in ammonia prices during the first quarter of 2008. Changes in ammonia prices will continue to impact this contract, which could affect our results in the future.

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.

We have a number of pending litigation matters and reserves related to our historical business operations that affect our corporate results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may continue to impact our future results.

In addition to these matters, we anticipate an increase in our non-cash pension costs of approximately $40 million during 2010 primarily as a result of our pension plan asset performance during 2008. Overall losses on our pension assets will be amortized into our future net benefit cost through 2011. Despite the increased expense, we do not anticipate making any contributions to our primary pension plan in 2010. For further discussion of our primary pension plan and related net benefit cost, see Item 8, Financial Statements and Supplementary Data, Note 14.

Extinguishment of Debt. During 2007, we incurred losses of $291 million in conjunction with repurchasing or refinancing more than $5 billion of our debt. For further information on our debt, see Item 8, Financial Statements and Supplementary Data, Note 12.

Interest and Debt Expense

Our interest and debt expense for the years ended December 31, 2009, 2008 and 2007 was $1.0 billion, $0.9 billion and $1.0 billion. During 2009, our interest and debt expense increased as compared to the prior year due primarily to higher interest rates and amortization of discounts related to debt issuances and other financing obligations, net of retirements. During 2008, our interest and debt expense decreased as compared to 2007 primarily due to debt repurchases in 2007 and 2008, net of issuances. See Item 8, Financial Statements and Supplementary Data, Note 12, for a further discussion.

Income Taxes

	Years Ended December 31,		
	2009	2008	2007
	(In millions)		
Income tax expense (benefit)	$(399)	$(245)	$222
Effective tax rate	46%	24%	33%

In 2009, our overall effective tax rate on continuing operations differed from the statutory rate due primarily to recording an $88 million income tax benefit relating to a U.S. tax loss on the liquidation of certain foreign entities. Following the 2009 sale of the remaining significant non-core international power projects, these entities had no liquidating value. As these entities had tax basis, the liquidation resulted in a tax loss. In 2008, our overall effective tax rate on continuing operations differed from the statutory rate due primarily to: (i) a Brazilian ceiling test charge in our exploration and production operations that did not have a corresponding U.S. or Brazilian tax benefit and (ii) the establishment of a valuation allowance against deferred tax assets (associated with Brazilian net operating losses) based on uncertainties about our ability to realize these assets. In 2007, our overall effective tax rate on continuing operations was impacted primarily by earnings from unconsolidated affiliates where we anticipate receiving dividends that qualify for the dividend received deduction. For a discussion of these and other items affecting our effective tax rates in each year and other tax matters, see Item 8, Financial Statements and Supplementary Data, Note 5.

Discontinued Operations

In 2007, our income from discontinued operations was due to a gain on the sale of ANR and related operations of $648 million, net of income taxes of $354 million as further discussed in Item 8, Financial Statements and Supplementary Data, Note 2.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 13.

Climate Change and Energy Legislation and Regulation. There are various legislative and regulatory measures relating to climate change and energy policies that have been proposed and, if enacted, will likely impact our business.

Climate Change Legislation and Regulation. Measures to address climate change and greenhouse gas (GHG) emissions are in various phases of discussions or implementation at international, federal, regional and state levels. These measures 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. Over 50 countries, including the U.S. and Brazil, have submitted formal pledges to cut or limit their emissions in response to the United Nations- sponsored Copenhagen Accord. It is reasonably likely that federal legislation requiring GHG controls will be enacted within the next few years in the United States. Although it is uncertain what legislation will ultimately be enacted, it is our belief that cap-and-trade or other market-based legislation that sets a price on carbon emissions will increase demand for natural gas, particularly in the power sector. We believe this increased demand will occur due to substantially less carbon emissions associated with the use of natural gas compared with alternate fuel sources for power generation, including coal and oil-fired power generation. However, the actual impact on demand will depend on the legislative provisions that are ultimately adopted, including the level of emission caps, allowances granted, offset programs established, cost of emission credits and incentives provided to other fossil fuels and lower carbon technologies like nuclear, carbon capture sequestration and renewable energy sources.

It is also reasonably likely that any federal legislation enacted would increase our cost of environmental compliance by requiring us to install additional equipment to reduce carbon emissions from our larger facilities as well as to potentially purchase emission allowances. Based on 2008 operational data we reported to the California Climate Action Registry, our operations in the United States emitted approximately 13.9 million tonnes of carbon dioxide equivalent emissions during 2008. We believe that approximately 10.7 to 12.4 million tonnes of these GHG emissions, depending on how the legislation is interpreted, would be subject to regulations under the climate change legislation that passed in the U.S. House of Representatives (the House) in June 2009. Of these amounts that would be subject to regulation, we believe that approximately 4.5 million tonnes would be subject to the cap-and-trade rules contained in the proposed legislation and the remainder would be subject to performance standards. As proposed by the House, the portion of our GHG emissions that would be subject to cap-and-trade rules could require us to purchase allowances or offset credits and the portion of our GHG emissions that would be subject to performance standards could require us to install additional equipment or initiate new work practice standards to reduce emission levels at many of our facilities. The costs of purchasing emission allowances or offset credits and installing additional equipment or changing work practices would likely be material. Increases in costs of our suppliers to comply with such cap-and-trade rules and performance standards, such as the electricity we purchase in our operations, could also be material and would likely increase our costs of operations. Although we believe that many of these costs should be recoverable in our sales price for natural gas and the rates charged by our pipelines, recovery through these mechanisms is still uncertain at this time. A climate change bill was also voted upon favorably by the Senate Committee on Energy and Public Works (the Committee) in November 2009 and has been ordered to be reported out of the Committee. Any final bill passed out of the U.S. Senate will likely see further substantial changes, and we cannot yet predict the form it may take, the timing of when any legislation will be enacted or implemented or how it may impact our operations if ultimately enacted.

The Environmental Protection Agency (EPA) finalized regulations to monitor and report GHG emissions on an annual basis. The EPA also proposed new regulations to regulate GHGs under the Clean Air Act, which the EPA has indicated could be finalized as early as March 2010. The effective date and substantive requirements of any EPA final rule is subject to interpretation and possible legal challenges. In addition, it is uncertain whether federal legislation might be enacted that either delays the implementation of any climate change regulations of the EPA or adopts a different statutory structure for regulating GHGs than is provided for pursuant to the Clean Air Act. Therefore, the potential impact on our operations and construction projects remains uncertain.

In addition, in March 2009, the EPA proposed a rule impacting emissions from reciprocating internal combustion engines, which would require us to install emission controls on engines on our pipeline systems. It is expected that the rule will be finalized in August 2010. As proposed, engines subject to the regulations would have to be in compliance by August 2013. Based upon that timeframe, we would expect that we would commence incurring expenditures in late 2010, with the majority of the work and expenditures incurred in 2011 and 2012. If the regulations are adopted as proposed, we would expect to incur approximately $60 million in capital expenditures over the period from 2010 to 2013.

Legislative and regulatory efforts are underway in various states and regions. These rules once finalized may impose additional costs on our operations and permitting our facilities, which could include costs to purchase offset credits or emission allowances, to retrofit or install equipment or to change existing work practice standards. In addition, various lawsuits have been filed seeking to force further regulation of GHG emissions, as well as to require specific companies to reduce GHG emissions from their operations. Enactment of additional regulations by the federal or state governments, as well as lawsuits, could result in delays and have negative impacts on our ability to obtain permits and other regulatory approvals with regard to existing and new facilities, could impact our costs of operations, as well as require us to install new equipment to control emissions from our facilities, the costs of which would likely be material.

Energy Legislation. In conjunction with these climate change proposals, there have been various federal and state legislative and regulatory proposals that would create additional incentives to move to a less carbon intensive footprint . These proposals would establish renewable energy and efficiency standards at both the federal and state level, some of which would require a material increase of renewable sources, such as wind and solar power generation, over the next several decades. There have also been proposals to increase the development of nuclear power and commercialize carbon capture and sequestration especially at coal fired facilities. Other proposals would establish incentives for energy efficiency and conservation. Although it is reasonably likely that many of these proposals will be enacted over the next few years, we cannot predict the form of any laws and regulations that might be enacted, the timing of their implementation, or the precise impact on our operations or demand for natural gas. However, such proposals if enacted could negatively impact natural gas demand over the longer term.

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Liquidity and Capital Resources

Our continued focus has been on expanding our core pipeline and exploration and production businesses and to build liquidity to fund that growth. Our primary sources of cash are cash flows generated from our operations and amounts available to us under our revolving credit facilities. As conditions warrant, we may also generate funds through additional bank financings, project financings, capital market activities and asset sales. Our primary uses of cash are funding the capital expenditure programs, meeting operating needs and repaying debt when due or repurchasing debt when conditions warrant. We believe we are well positioned in 2010 to meet these obligations based on the anticipated performance of our core businesses, our financing actions taken to date or planned in 2010, and the additional steps we announced in November 2009 to enhance our liquidity.

Available Liquidity and Liquidity Outlook for 2010. At December 31, 2009, we had available liquidity of approximately $1.8 billion (approximately $0.5 billion cash, $1.3 billion of available credit facility), exclusive of approximately $0.4 billion of combined cash /credit facility capacity of EPB and Ruby. In 2009, we took a number of actions to generate additional liquidity and address the instability in the global financial markets including reducing our 2009 capital program, obtaining a 50 percent partner on our Ruby pipeline project (as further described below) and raising $2.1 billion of net liquidity in financings. These 2009 financings included (i) the issuance of approximately $500 million of El Paso notes and $250 million of TGP notes, (ii) completing two additional facilities that provide a combined $300 million of letter of credit capacity, (iii) completing $300 million of financings related to our Elba Island LNG facility and Elba Express pipeline project, (iv) extending our $300 million El Paso Exploration and Production Company 364-day revolving credit facility without any additional collateral requirements to maintain the current borrowing base, (v) raising $215 million in conjunction with contributing additional interests in CIG to our master limited partnership, and (vi) selling approximately $300 million of non-core assets.

Our 2010 capital programs anticipate planned cash capital expenditures in our operations as follows:

	Total (In billions)
Pipelines	
Maintenance	$ 0.4
Growth[1]	2.5
Exploration and Production	1.1
Other	0.1
	$ 4.1

(1) Our pipeline growth capital expenditures reflect 100 percent of the capital related to the Ruby pipeline project. In 2009, we obtained a partner on this project as described below.

Although our 2010 pipeline capital requirements are significant, our 2011 requirements decline significantly, and by the end of 2011 most of our backlog will be placed in service. Our capital program is designed to deliver on our pipeline expansion backlog while keeping our exploration and production capital spend levels essentially consistent with 2009, allowing for continued reserve growth. In addition to our capital needs, in 2010 we have approximately $250 million of debt (excluding Ruby debt of approximately $217 million which we anticipate will convert into Ruby preferred equity) that will mature; however, our primary revolving credit facility is not scheduled for renewal until late 2012.

We plan to meet these requirements through a variety of measures in 2010 which include (i) generating positive operating cash flows from our core operations (ii) raising approximately $1.5 billion in third party financing for Ruby expected to close in the first half of 2010 (of which we expect to borrow approximately $1 billion in 2010), (iii) receiving approximately $300 million in committed funding from Global Infrastructure Partners (GIP) for the Ruby project, and (iv) selling $300 million to $500 million of assets. We will also consider additional opportunities with our MLP as the markets permit.

In November 2009, we announced additional actions for 2010 to provide incremental funding and further improve our financial flexibility, including a reduction of $150 million in annual operating and administrative expenses**,** the sale of $300 million to $500 million of assets, and a reduction in our quarterly dividend for annual cash savings of approximately $112 million. As part of this plan, in February 2010 we entered into an agreement to sell our interest in Mexican pipeline and compression assets for $300 million which is expected to close in the second quarter of 2010 subject to lender consent and Mexican regulatory approval.

We believe the actions planned for 2010 will provide sufficient liquidity to meet our operating, financing and capital needs in 2010. However, there are a number of factors that could impact our plans, including our ability to access the financial markets to fund our long-term capital needs if the financial markets are restricted, a further decline in commodity prices, or if any of our announced actions are not sufficient. If these events occur, additional adjustments to our plan and outlook may be required which could impact our financial and operating performance including reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets.

Ruby financing. During the third quarter of 2009, we entered into an agreement with several infrastructure funds managed by GIP, whereby they will invest up to $700 million in Ruby Pipeline Holding Company L.L.C. (Ruby) in three major tranches including (i) a series of 7 percent loans totaling $405 million ($217 million of which has been borrowed as of December 31, 2009), which will be converted into a preferred equity interest in Ruby upon satisfaction of certain conditions, (ii) $145 million which was contributed in October 2009 as a convertible preferred equity interest in Ruby and simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains Investment Company (Cheyenne Plains) with a 15 percent rate of return until the Ruby pipeline project is placed in-service, among other conditions and (iii) up to an additional $150 million of convertible preferred equity to be made to Ruby under the conditions that all FERC approvals for construction of the project are obtained and third party financing of approximately $1.4 billion is secured by Ruby by December 2010. The convertible preferred equity interest in Ruby will earn a 13 percent yield beginning at final project completion. GIP will have the right to convert its preferred equity to common equity in Ruby at any time. However, the preferred equity is subject to a mandatory conversion to common equity upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements.

If all conditions to closing are satisfied or waived, at the time of project completion, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, the GIP preferred equity interests in Ruby and Cheyenne Plains, amounts borrowed under GIP s loan commitment to Ruby and a 15 percent return on all outstanding amounts, must be repaid in cash to GIP if (i) all FERC approvals for construction of the Ruby pipeline project are not obtained by December 2010, (ii) third party financing of approximately $1.4 billion is not secured by Ruby by December 2010 or (iii) the Ruby pipeline project is not placed in-service within 16 months of obtaining all FERC approvals. Additionally, if the financings are not completed, GIP has the option to convert its preferred interest in Cheyenne Plains to a 50 percent common interest in Cheyenne Plains. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in our MLP.

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Overview of 2009 Cash Flow Activities. During 2009, we generated positive operating cash flow of approximately $2.1 billion primarily from our pipeline and exploration and production operations. We also generated approximately $0.3 billion from the sale of certain non-core power and exploration and production assets and $1.6 billion from debt issuances in 2009 (including consolidated project financings). We utilized these amounts to fund our capital programs, refinance 2009 debt maturities of $1.0 billion, and pay common and preferred dividends, among other items. For the year ended December 31, 2009 and 2008, our cash flows from continuing operations are summarized as follows:

	2009	2008
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Loss from continuing operations	$ (0.5)	$ (0.8)
Ceiling test charges	2.1	2.7
Other income adjustments	0.5	1.2
Change in other assets and liabilities		(0.7)
Total cash flow from operations	$ 2.1	$ 2.4
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.3	$ 0.7
Other	0.1	0.1
	0.4	0.8
Continuing financing activities		
Net proceeds from the issuance of long-term debt	1.6	4.6
Net proceeds from issuance of noncontrolling interests	0.2	
Net proceeds from issuance of preferred stock of subsidiary	0.1	
	1.9	4.6
Total other cash inflows	$ 2.3	$ 5.4
Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 2.8	$ 2.8
Cash paid for acquisitions	0.1	0.4
	2.9	3.2
Continuing financing activities		
Payments to retire long-term debt and other financing obligations[1]	1.7	3.7
Dividends and other	0.2	0.2

	1.9	3.9
Total cash outflows	$ 4.8	$ 7.1
Net change in cash	$ (0.4)	$ 0.7

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 and Indemnifications

We are involved in 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, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Those arrangements with a specified dollar amount have a maximum stated value of approximately $0.8 billion, which primarily relates to indemnification arrangements associated with the sale of ANR, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Item 8, Financial Statements and Supplementary Data, Note 12. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. 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.

As of December 31, 2009, we have recorded obligations of $52 million related to our guarantee and indemnification arrangements. This liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification.

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, 2009, we had outstanding letters of credit of approximately $1.3 billion, including $0.7 billion of letters of credit securing our recorded obligations related to price risk management activities. For additional information on our counterparty credit and nonperformance risk, see Item 8, Financial Statements and Supplementary Data, Note 7. Depending on changes in commodity prices or interest rates, we could be required to post additional margin or may recover margin earlier than anticipated. A 10 percent change in natural gas and power prices would not have had a significant impact on the margin requirements of our derivative contracts as of December 31, 2009.

Interests in Variable Interest Entities

We have interests in several variable interest entities, primarily in Ruby. 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 any fees paid by the entity. As of December 31, 2009, there were no significant variable interest entities that we did not consolidate. For additional information regarding our interest in Ruby, see Item 8, Financial Statements and Supplementary Data, Note 18, Variable Interest Entities and Qualifying Special Purpose Entities.

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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 summarizes our contractual cash obligations as of December 31, 2009, for each of the periods presented:

	Due in Less than 1 Year	Due in 1 to 3 Years	Due in 3 to 5 Years	Thereafter	Total
			(In millions)		
Long-term financing obligations:					
Principal	$ 477	$ 2,985	$ 1,097	$ 9,423	$ 13,982
Interest	989	1,809	1,541	7,246	11,585
Liabilities from commodity-based derivative contracts	262	280	107	65	714
Other contractual liabilities	102	217	27	37	383
Operating leases	14	25	22	20	81
Other contractual commitments and purchase obligations:					
Transportation and storage	71	158	135	279	643
Other	1,453	440	73	259	2,225
Total contractual obligations	$ 3,368	$ 5,914	$ 3,002	$ 17,329	$ 29,613

Long-term Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities unless the instrument is otherwise puttable to us prior to their stated maturity date. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. For a further discussion of our debt obligations, see Item 8, Financial Statements and Supplementary Data, Note 12.

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 $333 million as of December 31, 2009 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 Item 8, Financial Statements and Supplementary Data, Note 14. We have also excluded from these amounts liabilities for unrecognized tax benefits of $260 million as of December 31, 2009, since we cannot reasonably estimate the time frame over which these amounts may be resolved.

Operating Leases. For a further discussion of these obligations, see Item 8, Financial Statements and Supplementary Data, Note 13.

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.

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Other Commitments. Included in these amounts are commitments for purchasing pipe and related assets in our pipeline operations, 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. Also included are long-term commitments by us related to right of way payments as further discussed in Item 8, Financial Statements and Supplementary Data, Note 13. We have excluded asset retirement obligations and reserves for litigation, environmental remediation and self-insurance claims, other than those disclosed above, 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. Our commodity-based derivative contracts are not currently designated as accounting hedges and include options, swaps and other natural gas, oil and power purchase and supply contracts that are not traded on active exchanges. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of December 31, 2009:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Total Fair Value
			(In millions)		
Assets	$ 220	99	5	9	$ 333
Liabilities	(262)	(280)	(107)	(65)	(714)
Total commodity-based derivatives	$ (42)	(181)	(102)	(56)	$ (381)

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2009 and 2008:

	Derivatives Designated as Accounting Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at December 31, 2007	$ (23)	$ (869)	$ (892)
Fair value of contracts settled	88	257	345
Changes in fair value of contracts	309	197	506
Reclassification of de-designated hedges	(395)	395	
Net option premiums paid (received)	21	(5)	16
Net change in contracts outstanding during the period	23	844	867
Fair value of contracts outstanding at December 31, 2008		(25)	(25)
Fair value of contracts settled		(851)	(851)
Changes in fair value of contracts		322	322

Net option premiums paid		173	173
Net change in contracts outstanding during the period		(356)	(356)
Fair value of contracts outstanding at December 31, 2009	$	$ (381)	$ (381)

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, and 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.

Reclassifications of De-designated Hedges. During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivative contracts related to our hedged natural gas and oil production volumes.

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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. The process of estimating natural gas and oil reserves, is complex, requiring significant judgment in the evaluation of all available geological, geophysical engineering and economic data. Our proved reserves are estimated at a property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who work closely with the operating groups. These engineers interact with engineering and geoscience personnel in each of our operating areas and accounting and marketing personnel to obtain the necessary data for projecting future production, costs, net revenues and ultimate recoverable reserves. Reserves are reviewed internally with senior management quarterly and presented to our Board of Directors in summary form on an annual basis. Additionally, on an annual basis each property is reviewed in detail by our centralized and operating divisional engineers to ensure forecasts of operating expenses, netback prices, production trends and development timing are reasonable. Our proved reserves are also reviewed by internal committees and the processes and controls used for estimating our proved reserves are reviewed by our 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, conducts an audit of the estimates of a significant portion of our proved reserves. In particular, Ryder Scott Company, L.P. conducted an audit of our estimates of proved reserves as of December 31, 2009.

As of December 31, 2009, of our total consolidated proved reserves, 33 percent were undeveloped (31 percent including Four Star) and 14 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 and any ceiling test charges 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, asset retirement costs and capitalized interest. Capitalized costs are maintained in full cost pools by geographic area, regardless of whether reserves are actually discovered. We record depletion expense of these capitalized amounts plus estimated finding and development costs 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. For more information regarding price sensitivities related to our estimated proved reserves, see Part I, Item 1. Business, Natural Gas and Oil Properties.

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 unevaluated 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 for natural gas and oil properties, 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 deferred income taxes, are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted at 10 percent, plus the cost of unproved natural gas and oil properties not being amortized less related income tax effects. On December 31, 2009, we adopted the provisions of the SEC s final rule on Modernization of Oil and Gas Reporting. Among other things, the final rule revised the definition of proved reserves and required us to use a first day 12-month average price in calculating the ceiling test and estimating proved reserves rather than a period end spot price as required in prior periods. If the discounted future net cash flows are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level of discounted future net cash flows.

Cost-Based Regulation. We account for our regulated operations in accordance with current Financial Accounting Standard Board (FASB) accounting standards for rate-regulated operations. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management regularly assesses whether regulatory assets are probable of future recovery or if regulatory liabilities are probable of being refunded to our customers by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. We periodically evaluate the applicability of accounting standards related to regulated operations, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to reduce certain of our asset balances to reflect a market basis lower than cost and write-off the associated regulatory assets.

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, 2009, we had accrued approximately $67 million for legal matters, which has not been reduced by $1 million of related insurance receivables, and $189 million for environmental matters, which has not been reduced by $24 million for amounts to be paid directly under government sponsored programs or through settlement arrangements. Our environmental estimates range from approximately $189 million to approximately $381 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 ($10 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($179 million to $371 million) and the lower end of the expected range has been accrued.

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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 $0.8 billion. As of December 31, 2009, we have recorded obligations of $52 million related to our guarantee 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, 2009, our pension plans were under funded by $154 million and our other postretirement benefit plans were under funded by $399 million. Our pension and other postretirement benefit obligations and net benefit costs 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.

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 inactive 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, 2009, we had deferred net losses of approximately $682 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, 2009 (in millions):

	Pension Benefits		**Other Postretirement Benefits**	
	Net Benefit Expense (Income)	**Change in Funded Status and Pretax Accumulated Other Comprehensive Income**	**Net Benefit Expense (Income)**	**Change in Funded Status and Pretax Accumulated Other Comprehensive Income**
One percent increase in:				
Discount rates	$ (7)	$ 161	$ 1	$ 50
Expected return on plan assets	(22)		(2)	
Rate of compensation increase	2	(5)		
Health care cost trends			3	(47)
One percent decrease in:				
Discount rates	$ 8	$ (187)	$ (3)	$ (54)

Expected return on plan assets[1]	22		2	
Rate of compensation increase	(1)	4		
Health care cost trends			(3)	42

(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 change significantly.

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 $85 million higher for the year ended December 31, 2009.

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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 extent to which we rely on pricing information received from third parties in developing these assumptions is based, in part, on whether the information considers the availability of observable data in the marketplace. For example, in relatively illiquid markets such as the PJM forward power market, we may make adjustments to the pricing information we receive from third parties based on our evaluation of whether third party market participants would use pricing assumptions consistent with these sources.

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 natural gas, oil and power prices at December 31, 2009:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 127	$ (29)	$ (156)	$ 290	$ 163
Other commodity-based derivatives	(508)	(517)	(9)	(500)	8
Total	$ (381)	$ (546)	$ (165)	$ (210)	$ 171

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, 2009:

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 127	$ 126	$ (1)	$ 128	$ 1
Other commodity-based derivatives	(508)	(495)	13	(522)	(14)
Total	$ (381)	$ (369)	$ 12	$ (394)	$ (13)

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 and non-performance risk of our counterparties. We adjust the fair value of our derivative assets for the risk of non-performance of our counterparties considering the collateral posted for the derivative and changes in the counterparties   creditworthiness, which is measured in part based on changes in their bond yields, changes in actively traded credit default swap prices (if available) and other information about their credit standing. We adjust the fair value of our derivative liabilities for our creditworthiness utilizing similar inputs considering cash collateral we have posted with our counterparties.

The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from potential changes in credit risk at December 31, 2009:

		Change in Credit Risk			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(In millions)				
Production-related derivatives	$ 127	$ 126	$ (1)	$ 128	$ 1
Other commodity-based derivatives	(508)	(501)	7	(515)	(7)
Total	$ (381)	$ (375)	$ 6	$ (387)	$ (6)

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 reflect our assessment of tax positions taken, and the resulting tax basis, and reflect our conclusions about which positions 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 5.

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.

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. 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 or through a structured sale which would not result in any additional deferred tax liabilities.

Asset and Investment Impairments. The accounting rules on asset and investment impairments require us to continually monitor our businesses, the business environment and the performance of our investments 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 and discount rates. The assessment of project level cash flows requires significant 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 that are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can, and often do, differ from our estimates.

We utilize the cash flow projections to 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 and whether any decline in this fair value below our carrying amount is considered to be other than temporary. If an impairment is indicated, we record an impairment charge for the excess of carrying value of the asset over its fair value. During the year ended December 31, 2009, we recorded impairments of $21 million related to our long-lived assets and other assets. We recorded impairments of our long-lived assets of $41 million and $20 million and impairments and losses on our investments in and advances to unconsolidated affiliates of $127 million and $75 million during the years ended December 31, 2008 and 2007. Future changes in the economic and business environment can impact our assessments of potential impairments.

New Accounting Pronouncements Issued But Not Yet Adopted

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

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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

- Changes in natural gas and oil prices impact the amounts at which we sell our natural gas and oil in our Exploration and Production segment, affect gas not used in the operations of our Pipelines segment and affect the fair value of our natural gas and oil derivative contracts held in our Exploration & Production and Marketing segments;
- Changes in natural gas locational price differences also affect amounts at which we sell our natural gas and oil production, the fair values of any related derivative products and affect our ability to optimize pipeline transportation capacity contracts held in our Marketing segment; and
- Changes in electricity prices and locational price differences affect 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 result in increases or decreases in the unrealized value of our derivative positions; and
- Changes in interest rates used to discount liabilities result in higher or lower accretion expense over time.

Where practical, we manage these various 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 are 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 Item 8, Financial Statements and Supplementary Data, Notes 1 and 8.

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 contracts 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 production.

Other Commodity-Based Derivatives

In our Marketing segment, we have long-term natural gas and power derivative contracts which include forwards, swaps, options and futures that we either intend to manage until their expiration or seek opportunities to liquidate to the extent it is economical and prudent. We utilize a sensitivity analysis to manage the commodity price risk associated with these contracts.

Sensitivity Analysis

The table below presents the hypothetical sensitivity of our production-related derivatives and our other commodity-based derivatives to changes in fair values arising from immediate selected potential changes in the market prices (primarily natural gas, oil and power prices and basis differentials) used to value these contracts. This table reflects the sensitivities of the derivative contracts only and does not include any underlying hedged commodities.

		Change in Market Price			
		10 Percent Increase		**10 Percent Decrease**	
	Fair Value	**Fair Value**	**Change**	**Fair Value**	**Change**
			(In millions)		
Production-related derivatives net assets (liabilities)					
December 31, 2009	$ 127	$ (29)	$ (156)	$ 290	$163
December 31, 2008	$ 682	$ 582	$ (100)	$ 785	$103
Other commodity-based derivatives net assets (liabilities)					
December 31, 2009	$(508)	$(517)	$ (9)	$(500)	$ 8
December 31, 2008	$(707)	$(719)	$ (12)	$(695)	$ 12

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 effective 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.

	December 31, 2009								**December 31, 2008**	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2010	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**	**Fair Value**	**Carrying Amounts**	**Fair Value**
					(In millions)					
Fixed rate long-term debt and other obligations(1)	$458	$665	$ 458	$ 550	$450	$9,124	$11,705	$12,170	$11,628	$9,438

Average interest rate	7.4%	7.5%	6.9%	14.5%	7.4%	7.6%				
Variable rate long-term debt and other obligations[1]	$ 19	$ 22	$1,837	$ 25	$ 27	$ 233	$ 2,163	$ 1,981	$ 2,280	$1,789
Average interest rate	5.0%	4.8%	1.9%	4.8%	4.8%	4.5%				

(1) Includes current portion

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, 2009. 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, 2009. The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

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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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the Index at Item 15(a). 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 has a 50% interest) as of December 31, 2009 and 2008 and for the three years in the period ended December 31, 2009 and Four Star Oil & Gas Company (a corporation in which the Company has approximately a 49% interest) as of December 31, 2008 and for the two years in the period ended December 31, 2008 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 investments in unconsolidated affiliates includes approximately $674 million from Citrus Corp. and Subsidiaries as of December 31, 2009 and approximately $744 million from Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company combined at December 31, 2008, and the Company s earnings from unconsolidated affiliates includes approximately $65 million for the year ended December 31, 2009 from Citrus Corp. and approximately $147 million and $149 million for the years ended December 31, 2008 and 2007, respectively, from Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company combined, all of which were 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, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 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 December 31, 2009 the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements, effective January 1, 2009 the Company adopted accounting standards for the presentation and disclosure of noncontrolling interests in the financial statements, effective January 1, 2008 the Company adopted the measurement provisions of the accounting standards for retirement benefits, and effective January 1, 2007 the Company adopted the accounting standards related to income tax contingencies.

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, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
March 1, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2009, 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, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of El Paso Corporation and our report dated March 1, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
March 1, 2010

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Report of Independent Auditors

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 comprehensive income, of stockholders equity 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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 auditing standards generally accepted in the United States of America and 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.

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 25, 2010

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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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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 20, 2009

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

	Year Ended December 31,		
	2009	2008	2007
Operating revenues			
Pipelines	$ 2,767	$ 2,684	$ 2,494
Exploration and Production	1,828	2,762	2,300
Marketing	29	(83)	(219)
Corporate and other	7		73
	4,631	5,363	4,648
Operating expenses			
Cost of products and services	207	245	245
Operation and maintenance	1,257	1,190	1,333
Ceiling test charges	2,123	2,669	
Depreciation, depletion and amortization	867	1,205	1,176
Taxes, other than income taxes	228	284	249
	4,682	5,593	3,003
Operating income (loss)	(51)	(230)	1,645
Earnings from unconsolidated affiliates	67	48	101
Loss on debt extinguishment			(291)
Other income	144	94	214
Other expenses	(25)	(32)	(11)
Interest and debt expense	(1,008)	(914)	(994)
Income (loss) before income taxes from continuing operations	(873)	(1,034)	664
Income tax (benefit) expense	(399)	(245)	222
Income (loss) from continuing operations	(474)	(789)	442
Discontinued operations, net of income taxes			674
Net income (loss)	(474)	(789)	1,116
Net income attributable to noncontrolling interests	(65)	(34)	(6)
Net income (loss) attributable to El Paso Corporation	(539)	(823)	1,110
Preferred stock dividends of El Paso Corporation	37	37	37
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (576)	$ (860)	$ 1,073
Basic earnings (loss) per common share			
Income (loss) from continuing operations attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (1.24)	$ 0.57
Discontinued operations, net of income taxes			0.97

Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (1.24)	$ 1.54
Diluted earnings (loss) per common share			
Income (loss) from continuing operations attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (1.24)	$ 0.57
Discontinued operations, net of income taxes			0.96
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (1.24)	$ 1.53

See accompanying notes.

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

	December 31, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 635	$ 1,024
Accounts and notes receivable		
Customer, net of allowance of $8 in 2009 and $9 in 2008	346	466
Affiliates	92	133
Other	115	217
Materials and supplies	175	187
Assets from price risk management activities	221	876
Deferred income taxes	298	
Other	126	148
Total current assets	2,008	3,051
Property, plant and equipment, at cost		
Pipelines	19,722	18,042
Natural gas and oil properties, at full cost	20,846	20,009
Other	314	342
	40,882	38,393
Less accumulated depreciation, depletion and amortization	22,987	20,535
Total property, plant and equipment, net	17,895	17,858
Other assets		
Investments in unconsolidated affiliates	1,718	1,703
Assets from price risk management activities	123	201
Other	761	855
	2,602	2,759
Total assets	$ 22,505	$ 23,668

See accompanying notes.

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

	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 459	$ 372
Affiliates	7	6
Other	424	618
Short-term financing obligations, including current maturities	477	1,090
Liabilities from price risk management activities	269	250
Asset retirement obligations	158	83
Accrued interest	208	192
Other	684	632
Total current liabilities	2,686	3,243
Long-term financing obligations, less current maturities	13,391	12,818
Other		
Liabilities from price risk management activities	462	767
Deferred income taxes	339	565
Other	1,491	1,679
	2,292	3,011
Commitments and contingencies (Note 13)		
Preferred stock of subsidiary	145	
Equity		
El Paso Corporation s 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 716,041,302 shares in 2009 and 712,628,781 shares in 2008	2,148	2,138
Additional paid-in capital	4,501	4,612
Accumulated deficit	(3,192)	(2,653)
Accumulated other comprehensive loss	(718)	(532)
Treasury stock (at cost); 14,761,654 shares in 2009 and 14,061,474 shares in 2008	(283)	(280)
Total El Paso Corporation stockholders equity	3,206	4,035
Noncontrolling interests	785	561
Total equity	3,991	4,596

Total liabilities and equity	$ 22,505	$ 23,668

See accompanying notes.

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

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities			
Net income (loss)	$ (474)	$ (789)	$ 1,116
Less income from discontinued operations, net of income taxes			674
Income (loss) from continuing operations	(474)	(789)	442
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	867	1,205	1,176
Ceiling test charges	2,123	2,669	
Deferred income tax (benefit) expense	(427)	(172)	182
Earnings from unconsolidated affiliates, adjusted for cash distributions	21	132	88
Loss on debt extinguishment			291
Other non-cash income items	57	32	(31)
Asset and liability changes			
Accounts and notes receivable	142	129	213
Change in price risk management activities, net	(46)	(461)	(69)
Accounts payable	(140)	(88)	(67)
Change in margin and other deposits	22	24	90
Other asset changes	(74)	(32)	(150)
Other liability changes	44	(279)	(327)
Cash provided by continuing activities	2,115	2,370	1,838
Cash used in discontinued activities			(33)
Net cash provided by operating activities	2,115	2,370	1,805
Cash flows from investing activities			
Capital expenditures	(2,810)	(2,757)	(2,495)
Cash paid for acquisitions, net of cash acquired	(130)	(362)	(1,197)
Net proceeds from the sale of assets and investments	351	682	106
Net change in restricted cash	49	39	33
Other	(41)	50	3
Cash used in continuing activities	(2,581)	(2,348)	(3,550)
Cash provided by discontinued activities			3,660
Net cash provided by (used in) investing activities	(2,581)	(2,348)	110
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	1,618	4,641	6,624
Payments to retire long-term debt and other financing obligations	(1,668)	(3,679)	(8,902)
Net proceeds from issuance of noncontrolling interests	212	15	538
Net proceeds from the issuance of preferred stock of subsidiary	145		

Dividends paid	(177)	(157)	(149)
Distributions to noncontrolling interest holders	(48)	(29)	
Repurchase of common shares		(77)	
Contributions from discontinued operations			3,344
Other	(5)	3	5
Cash provided by continuing activities	77	717	1,460
Cash used in discontinued activities			(3,627)
Net cash provided by (used in) financing activities	77	717	(2,167)
Change in cash and cash equivalents	(389)	739	(252)
Cash and cash equivalents			
Beginning of period	1,024	285	537
End of period	$ 635	$ 1,024	$ 285
Supplemental cash flow information related to continuing operations			
Interest paid, net of amounts capitalized	$ 968	$ 914	$ 1,054
Income tax payments (refunds)	(24)	12	34

See accompanying notes.

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

	Year Ended December 31,					
	2009		2008		2007	
	Shares	Amount	Shares	Amount	Shares	Amount
El Paso Corporation stockholders equity:						
Preferred stock, $0.01 par value:						
Balance at beginning and end of year	1	$ 750	1	$ 750	1	$ 750
Common stock, $3.00 par value:						
Balance at beginning of year	712	2,138	709	2,128	706	2,118
Other, net	4	10	3	10	3	10
Balance at end of year	716	2,148	712	2,138	709	2,128
Additional paid-in capital:						
Balance at beginning of year		4,612		4,699		4,804
Dividends		(149)		(163)		(149)
Other, including stock-based compensation		38		76		44
Balance at end of year		4,501		4,612		4,699
Accumulated deficit:						
Balance at beginning of year		(2,653)		(1,834)		(2,940)
Net income (loss) attributable to El Paso Corporation		(539)		(823)		1,110
Cumulative effect of adopting new tax accounting standards						(4)
Cumulative effect of adopting new pension accounting standards, net of income tax of $2				4		
Balance at end of year		(3,192)		(2,653)		(1,834)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(532)		(272)		(343)
Other comprehensive income (loss)		(186)		(263)		80
Cumulative effect of adopting new pension accounting standards, net of income tax of $2 in 2008 and $4 in 2007				3		(9)
Balance at end of year		(718)		(532)		(272)

Treasury stock, at cost:						
Balance at beginning of year	(14)	(280)	(9)	(191)	(9)	(203)
Share repurchases			(5)	(77)		
Stock-based and other compensation	(1)	(3)		(12)		12
Balance at end of year	(15)	(283)	(14)	(280)	(9)	(191)
Total El Paso Corporation stockholders equity at end of year		3,206		4,035		5,280
Noncontrolling interests:						
Balance at beginning of year		561		565		31
Distributions to noncontrolling interests		(48)		(29)		
Issuance of noncontrolling interests		212		15		538
Net income attributable to noncontrolling interests (Note 15)		60		34		6
Other				(24)		(10)
Balance at end of year		785		561		565
Total equity at end of year		$ 3,991		$ 4,596		$ 5,845

See accompanying notes.

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

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (474)	$ (789)	$ 1,116
Pension and postretirement obligations:			
Unrealized actuarial gains (losses) arising during period (net of income taxes of $11 in 2009, $288 in 2008 and $91 in 2007)	36	(527)	181
Reclassifications of actuarial gains during period (net of income taxes of $16 in 2009, $8 in 2008 and $13 in 2007)	27	16	26
Cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $6 in 2009, $106 in 2008 and $2 in 2007)	11	191	(3)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $146 in 2009, $31 in 2008 and $65 in 2007)	(260)	57	(112)
Investments available for sale:			
Unrealized gains on investments available for sale arising during period (net of income taxes of $2 in 2007)			3
Realized gains on investments available for sale arising during period (net of income taxes of $8 in 2007)			(15)
Other comprehensive income (loss)	(186)	(263)	80
Comprehensive income (loss)	(660)	(1,052)	1,196
Comprehensive income attributable to noncontrolling interests	(65)	(34)	(6)
Comprehensive income (loss) attributable to El Paso Corporation	$ (725)	$ (1,086)	$ 1,190

See accompanying notes.

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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 United States (U.S.) generally accepted accounting principles (GAAP) and include the accounts of all consolidated subsidiaries after the elimination of all significant intercompany accounts and transactions. Certain amounts related to noncontrolling interests have been retrospectively adjusted within these consolidated financial statements to reflect the January 1, 2009 adoption of new presentation and disclosure requirements for noncontrolling interests. Our financial statements for prior periods also include reclassifications that were made to conform to the current year presentation, none of which impacted 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 interests in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity s losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control the 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 Federal Energy Regulatory Commission (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 Financial Accounting Standards Board s (FASB) accounting standards for regulated operations. Under these standards, 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 are expected to 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 related to gas not used in operations and other 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. We had $2 million of restricted cash in other current assets as of December 31, 2009 and 2008 and $8 million and $57 million in other non-current assets as of December 31, 2009 and 2008.

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 collectability and establish or adjust our allowance as necessary using the specific identification method.

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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. For a description of the methods we use to depreciate regulated property, plant and equipment, see Note 11.

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, as defined by the FERC. We include gains or losses on dispositions of operating units in operations and maintenance expense in our income statements.

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 as discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs quarterly. We transfer unproved property costs into the amortizable base when properties are determined to have proved reserves. In addition, in countries where a natural gas or oil reserve base exists, we transfer unproved property costs to the amortizable base when we have completed the evaluation of the unproved properties or they are determined to be impaired and as exploratory wells 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 in each country, net of related deferred income taxes, are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted at 10 percent, plus the cost of unproved natural gas and oil properties not being amortized plus the lower of cost or fair value of unproved natural gas and oil properties included in the amortizable base less related income tax effects. We perform this ceiling test calculation each quarter. Prior to December 31, 2009, we utilized end-of-period spot prices to determine future net revenues. As a result of our adoption of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we are required to use a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) to calculate the ceiling test. If total capitalized costs exceed the ceiling, we are required to write-down our capitalized costs to the ceiling. Any required write-down is included as a ceiling test charge on our income statement and as an increase to accumulated depreciation, depletion and amortization on our balance sheet. Prior to December 31, 2008, our ceiling test calculations included the effects of any derivative instruments we designated as, and that qualified as, cash flow hedges of anticipated future natural gas and oil production on the date of the calculation. During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivative contracts related to our hedged natural gas and oil production volumes. 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 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 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 assets to be sold in our financial statements as either held-for-sale or from discontinued operations when it becomes probable that we will dispose of the assets within the next twelve months and when they meet other criteria, including 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 from discontinued operations, and reflect the results of our discontinued operations in our income statement separately from those of continuing operations.

Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. Cash provided by (used in) discontinued activities in the operating activities section of our cash flow statement includes all operating cash flows generated by our discontinued businesses during the period. Proceeds from the sale of our discontinued operations are classified in cash provided by discontinued activities in the cash flows from investing activities section of our cash flow statement. To the extent these operations participated in our cash management program we reflect transactions related to the cash management program as financing activities in our cash flow statement. 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. We make contributions to our plans, if required, to fund the benefits to be paid out to participants and retirees. These contributions are invested until the benefits are paid out to plan participants. We record the net benefit cost related to these plans in our income statement. This net benefit cost 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 benefit plans, see Note 14.

In accounting for our pension and other postretirement benefit plans, we record an asset or liability based on the over funded or under funded status of each plan. Any deferred amounts related to unrecognized 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 all other operations until those gains and losses are recognized in the income statement.

Effective December 31, 2009, we expanded our disclosures about postretirement benefit plan assets as a result of new disclosure requirements. See Note 14 for these expanded disclosures.

Effective January 1, 2008, we adopted the measurement provisions of the accounting standards for retirement benefits that resulted in a change to the measurement date of our pension and other postretirement benefit plans from September 30 to December 31. We recorded a $4 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated deficit and a $3 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated other comprehensive loss upon the adoption of those provisions to reflect an additional three months of net periodic benefit income based on our September 30, 2007 measurement.

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 based on contractual 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 used in 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 from our shippers when the FERC allows us to retain the volumes at the market prices required 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 natural gas liquids. 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 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 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 Environmental Protection Agency 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.

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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 relate primarily to 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. We also hold other derivatives not intended to hedge these exposures, including those related to our legacy trading activities.

Our derivatives are reflected on our balance sheet at their fair value as assets and liabilities from price risk management activities. Cash collateral associated with our derivatives is not significant to our financial statements. 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 on counterparties where we have a legal right of offset. See Note 8 for a further discussion of our price risk management activities.

Derivatives that we have designated as accounting hedges impact our revenues or expenses based on the nature and timing of the transactions that they hedge. Derivatives that we have not designated as hedges are marked-to-market each period and changes in their fair value, as well as any realized amounts, are generally reflected as operating revenues in both our Exploration and Production segment and our Marketing segment.

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.

In 2007, we adopted new accounting standards which required us to evaluate our tax positions for all jurisdictions and for all years where the statute of limitations has not expired and we are required 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 tax benefit. 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.

Accounting for Asset Retirement Obligations

We record a liability for legal obligations associated with the replacement, removal or retirement of our long-lived assets in the period the obligation is incurred. Our asset retirement liabilities are initially 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 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 accretion of the liabilities described above.

Accounting for Stock-Based Compensation.

We measure all employee stock-based compensation awards at fair value on the date awards are granted to employees and recognize compensation cost in our financial statements over the requisite service period. For additional information on our stock-based compensation awards, see Note 16.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2009, the following accounting standards had not yet been adopted by us.

Transfers of Financial Assets. In June 2009, the FASB updated accounting standards for financial asset transfers. Among other items, this update eliminated the concept of a qualifying special-purpose entity (QSPE) for purposes of evaluating whether an entity should be consolidated or not. The changes are effective for existing QSPEs as of January 1, 2010 and for transactions entered into on or after January 1, 2010. The adoption of this accounting standard in January 2010 did not have a material impact on our financial statements as we amended our existing accounts receivable sales programs in January 2010. For further information, see Note 18.

Variable Interest Entities. In June 2009, the FASB updated accounting standards for variable interest entities to revise how companies determine the primary beneficiary of these entities, among other changes. Companies will now be required to use a qualitative approach based on their responsibilities and power over the entities operations, rather than a quantitative approach in determining the primary beneficiary as previously required. The adoption of this accounting standard in January 2010 did not have a material impact on our financial statements.

2. Acquisitions and Divestitures

Acquisitions

Gulf LNG. In February 2008, we paid approximately $295 million to complete the acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, a LNG terminal which is currently under construction in Pascagoula, Mississippi. The terminal is expected to be placed in service in late 2011. In addition, we have a commitment to loan Gulf LNG up to $150 million under which we have advanced approximately $56 million and $26 million as of December 31, 2009 and 2008. Our partner in this project has a commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

Exploration and Production properties. In 2009, we acquired domestic natural gas and oil properties for approximately $92 million, including producing properties of approximately $87 million located primarily in the Altamont-Bluebell-Cedar Rim Field in Utah. During 2008, we acquired interests in domestic natural gas and oil properties for $61 million, including producing properties of $51 million. During 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas for $254 million and also acquired Peoples Energy Production Company (Peoples) for $887 million. Peoples was 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.

Divestitures

During 2009, 2008 and 2007, we sold a number of assets and investments the proceeds of which are as follows:

	2009	2008	2007
		(In millions)	
Exploration and Production	$ 93	$ 637	$ 2
Power	190	16	1
Pipelines	65	2	36
Other		20	27
Total continuing[(1)]	348	675	66
Discontinued			3,660
Total	$ 348	$ 675	$ 3,726

(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 $3 million,

$7 million and $40 million for the years ended December 31, 2009, 2008 and 2007.

Exploration and Production. Assets sold in 2009 consisted of natural gas producing properties in the Central and Western divisions. Assets sold in 2008 consisted primarily of natural gas and oil properties in the Gulf Coast division.

Power. Assets sold in 2009 consisted of our investment in the Argentina-to-Chile pipeline and our interest in the Porto Velho power generation facility in Brazil. Assets sold in 2008 consist of power investments in Central America and Asia.

Pipelines. Assets sold consisted primarily of certain facilities and pipeline laterals.

Other. Assets sold consisted primarily of a fuel oil terminal in 2008 and a non-core investment in 2007.

Discontinued Operations and Assets Held for Sale

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.

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The summarized operating results of ANR and related operations were as follows:

	ANR and Related Operations (In millions)
Year Ended December 31, 2007	
Revenues	$ 101
Costs and expenses	(43)
Other expense[1]	(7)
Interest and debt expense	(10)
Income taxes	(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

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

3. Ceiling Test Charges

We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the years ended December 31, 2009 and 2008, we recorded the following ceiling test charges:

	2009	2008
	(In millions)	
Full cost pool:		
U.S.	$ 2,031	$ 2,181
Brazil	58	479
Egypt	34	9
Total	$ 2,123	$ 2,669

Note: A majority of the 2009 ceiling test charges were recorded during the first quarter of 2009 and all of the 2008 ceiling test charges were recorded during the fourth quarter of 2008. We did not record any ceiling test charges for the year ended December 31, 2007.

Through the third quarter of 2009, our quarterly impairment tests were based on the spot commodity prices at the end of each period. As a result of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we were required to use a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) when performing these ceiling tests. In calculating our ceiling test charges, we are also required to hold prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period.

4. Other Income and Other Expenses

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

	2009	2008	2007
		(In millions)	
Other Income			
Interest income	$ 26	$ 19	$ 49
Allowance for funds used during construction	61	37	32
Deferred taxes on allowance for funds used during construction	34	17	18
Reversal of liability for legacy crude oil purchases (see Note 17)			77
Gain on sale of non-equity method investments			24
Foreign currency gains	14		
Other	9	21	14
Total	$ 144	$ 94	$ 214
Other Expenses			
Foreign currency losses	$	$ 28	$ 1
Loss on sale of Porto Velho notes receivable	22		
Other	3	4	10
Total	$ 25	$ 32	$ 11

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5. 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:

	2009	2008	2007
		(In millions)	
Pretax Income (Loss)			
U.S.	$ (771)	$ (569)	$ 593
Foreign	(102)	(465)	71
	$ (873)	$ (1,034)	$ 664
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ (1)	$ (36)	$ (1)
State	24	(38)	33
Foreign	5	1	8
	28	(73)	40
Deferred			
Federal	(400)	(238)	217
State	(26)	27	(39)
Foreign	(1)	39	4
	(427)	(172)	182
Total income tax expense (benefit)	$ (399)	$ (245)	$ 222

Effective Tax Rate Reconciliation. Our income taxes included in income 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:

	2009	2008	2007
		(In millions, except rates)	
Income taxes at the statutory federal rate of 35%	$ (305)	$ (362)	$ 232
Increase (decrease)			
Sales and write-offs of foreign investments	(88)	(50)	1
Valuation allowances	47	202	10
Foreign income (loss) taxed at different rates	(42)	23	24
State income taxes, net of federal income tax effect	44	(6)	14
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(23)	(41)	(40)
Noncontrolling interest income not subject to U.S. tax	(23)	(12)	(2)
Audit settlements	(12)	2	
Texas margins tax credit on accumulated net operating loss			(16)
Other	3	(1)	(1)

Income taxes	$ (399)	$ (245)	$ 222
Effective tax rate	46%	24%	33%

In 2009, our effective tax rate was higher than the statutory rate primarily due to recording $88 million of income tax benefit relating to a U.S. tax loss on the liquidation of certain foreign entities. Following the 2009 sale of the remaining significant non-core international power projects, these entities had no liquidating value. As these entities had tax basis, the liquidation resulted in a tax loss. In 2008, our overall effective tax rate differed from the statutory rate due primarily to a $0.5 billion ceiling test charge on our Brazilian full cost pool that did not have a corresponding U.S. or Brazilian tax benefit. The impact of the ceiling test charge on our effective tax rate is included in *Foreign income (loss) taxed at different rates* and *Valuation allowances* in the above table.

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 or through a structured sale which would not result in any additional deferred tax liabilities. At December 31, 2009, the undistributed earnings of our unconsolidated affiliates for which we expect to receive a dividends received deduction was approximately $360 million.

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

	2009	2008
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 2,193	$ 2,669
Investments in affiliates	193	177
Regulatory and other assets	77	54
Total deferred tax liability	2,463	2,900
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,399	1,315
State	77	116
Foreign	202	147
Benefits and compensation	308	353
Price risk management activities	258	111
Legal and other reserves	240	200
Other	324	420
Valuation allowance	(384)	(337)
Total deferred tax asset	2,424	2,325
Net deferred tax liability	$ 39	$ 575

Cumulative undistributed earnings from substantially all of our foreign subsidiaries and foreign corporate joint ventures 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, 2009, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $85 million.

Unrecognized Tax Benefits (Liabilities for Uncertain Tax Matters). We are subject to taxation in the U.S. and various states and foreign jurisdictions. With a few exceptions, we are no longer subject to state, local or foreign income tax examinations by tax authorities for years prior to 1999 and U.S. income tax examinations for years prior to 2007. In November 2009, the Internal Revenue Service s (IRS) examination of El Paso s U.S. income tax returns for 2005 and 2006 was settled at the appellate level. The settlement of issues raised in this examination had a $12 million positive impact on our results of operations but did not materially impact our financial condition or liquidity. For years in which our returns are still subject to review, 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. We are currently unable to estimate the range of potential impacts the resolution of any contested matters could have on our financial statements. The following table shows the change in our unrecognized tax benefits:

	2009	2008
	(In millions)	
Balance at January 1	$ 173	$ 157
Additions:		
Tax positions taken in prior years	(2)	24

Tax positions taken in current year	87	32
Foreign currency fluctuations	3	
Reductions:		
Tax positions taken in prior years	(1)	(23)
Settlements with taxing authorities	4	(11)
Statute of limitations expiration	(4)	(5)
Foreign currency fluctuations		(1)
Balance at December 31	$ 260	$ 173

As of December 31, 2009, and 2008, approximately $258 million and $169 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. The significant increase primarily pertains to uncertainties related to the U.S. tax loss on the liquidation of certain foreign entities. 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.

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We recognize accrued interest related to unrecognized tax benefits and penalties as income tax expense. During 2009, 2008 and 2007, we recognized $3 million, $4 million and $6 million in interest and penalties related to the unrecognized tax benefits noted above. We had $52 million and $49 million accrued for the payment of interest and penalties as of December 31, 2009 and 2008.

Tax Credit and Net Operating Loss Carryovers. As of December 31, 2009, we have U.S. federal alternative minimum tax credits of $295 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2009:

	Carryover Period				
	2010	**2011-2014**	**2015-2019**	**2020-2029**	**Total**
			(In millions)		
U.S. federal net operating loss	$ 6	$ 12	$480	$2,989	$3,487
State net operating loss	53	260	814	1,090	2,217

We also had $512 million of foreign net operating loss carryovers and $71 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 the 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.

As of December 31, 2009, our valuation allowance primarily relates to deferred tax assets recorded on state and foreign net operating losses and temporary differences. In 2009, we increased our valuation allowance by $93 million on deferred tax assets associated with Brazil and Egypt net operating losses and reduced our valuation allowance by $46 million on deferred tax assets associated with expiring state net operating losses. In 2008, we provided a valuation allowance of $202 million on deferred tax assets associated with Brazil net operating losses and ceiling test charges. The valuation allowance was established primarily as a result of changes in the worldwide economic conditions creating uncertainty in our outlook as to future taxable income in that particular tax jurisdiction. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

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6. Earnings Per Share

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

	2009		2008		2007	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)					
Income (loss) from continuing operations	$ (474)	$ (474)	$ (789)	$ (789)	$ 442	$ 442
Net income attributable to noncontrolling interests	(65)	(65)	(34)	(34)	(6)	(6)
Preferred stock dividends of El Paso Corporation	(37)	(37)	(37)	(37)	(37)	(37)
Income (loss) from continuing operations attributable to El Paso Corporation s common stockholders	(576)	(576)	(860)	(860)	399	399
Discontinued operations, net of income taxes					674	674
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (576)	$ (576)	$ (860)	$ (860)	$ 1,073	$ 1,073
Weighted average common shares outstanding	696	696	696	696	696	696
Effect of dilutive securities:						
Options and restricted stock						3
Weighted average common shares outstanding and dilutive potential common shares	696	696	696	696	696	699
Basic and diluted earnings per common share:						
Income (loss) from continuing operations attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (0.83)	$ (1.24)	$ (1.24)	$ 0.57	$ 0.57
Discontinued operations, net of income taxes					0.97	0.96
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.83)	$ (0.83)	$ (1.24)	$ (1.24)	$ 1.54	$ 1.53

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 net income attributable to El Paso Corporation per common share is antidilutive. These potentially dilutive securities consist of our employee stock options, restricted stock, convertible preferred stock and trust preferred securities. For the years ended December 31, 2009 and 2008, we incurred losses attributable to El Paso Corporation 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 the year ended December 31, 2007, certain employee stock options, our trust preferred securities and our convertible preferred stock were antidilutive. For a discussion of our capital stock activity, our stock-based compensation arrangements, and other instruments noted above, see Notes 15 and 16.

7. Fair Value of Financial Instruments

On January 1, 2008, we adopted new fair value accounting and reporting standards that expanded the disclosure requirements for financial instruments and other derivatives recorded at fair value, and also required that a company s own credit risk be considered in determining the fair value of those instruments. The adoption of these standards resulted in a $6 million increase in operating revenues, a $4 million pre-tax increase in other comprehensive income, and a $10 million reduction of our liabilities to reflect the consideration of our credit risk on our liabilities that are recorded at fair value, after considering collateral related to these positions. On January 1, 2009, we adopted new accounting and reporting standards for our non-financial assets and liabilities that are measured at fair value on a non-recurring basis, which primarily relates to any impairment of long-lived assets or investments. During the year ended December 31, 2009, we did not have any non-financial assets and liabilities that were recorded at fair value subsequent to their initial measurement.

On January 1, 2009, we also adopted accounting standard updates regarding how companies should consider their own credit in determining the fair value of their liabilities that have third party credit enhancements related to them. Substantially all of the derivative liabilities in our Marketing segment are supported by letters of credit. Under these accounting standard updates, non-cash credit enhancements, such as letters of credit, should not be considered in determining the fair value of these liabilities, including derivative liabilities. Accordingly, we recorded a $34 million gain (net of $18 million of taxes), or $0.05 per share, in 2009 as a result of adopting these new accounting updates.

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We use various methods to determine the fair values of our financial instruments and other derivatives that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments and other derivatives into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels.

Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 instruments fair values are based on quoted prices for the instruments in actively traded markets. Included in this level are our marketable securities invested in non-qualified compensation plans whose fair value is determined using quoted prices.

Level 2 instruments fair values are primarily based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets). Included in this level are our interest rate swaps, production-related natural gas and oil derivatives and certain of our other natural gas derivatives (such as natural gas supply arrangements) whose fair values are based on commodity pricing data obtained from third party pricing sources. These fair values also consider our creditworthiness or that of our counterparties (adjusted for collateral related to our asset positions).

Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but their fair value also reflects adjustments for being in less liquid markets or having longer contractual terms. For these instruments, we obtain pricing data from third party pricing sources, adjust this data based on the liquidity of the underlying forward markets over the contractual terms and use the adjusted pricing data to develop an estimate of forward price curves that market participants would use. The curves are then used to estimate the value of settlements in future periods based on contractual settlement quantities and dates. Our valuation of these instruments considers specific contractual terms, statistical and simulation analysis, present value concepts and other internal assumptions related to (i) contract maturities that extend beyond the periods in which quoted market prices are available; (ii) the uniqueness of the contract terms; (iii) the limited availability of forward pricing information in markets where there is a lack of viable participants, such as in the Pennsylvania-New Jersey-Maryland (PJM) forward power market and the forward market for ammonia; and (iv) our creditworthiness or that of our counterparties (adjusted for collateral related to our asset positions). Since a significant portion of the fair value of our power-related derivatives and certain of our remaining natural gas derivatives with longer terms or in less liquid markets than similar Level 2 derivatives rely on the techniques discussed above, we classify these instruments as Level 3 instruments.

Listed below are the fair values of our financial instruments that are recorded at fair value classified in each level at December 31, 2009 and 2008 (in millions):

	December 31, 2009				December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ 169	$	$ 169	$	$ 727	$	$ 727
Other natural gas derivatives		106	21	127		141	31	172

Power-related derivatives			37	37			72	72
Interest rate and foreign currency derivatives		11		11		106		106
Marketable securities invested in non-qualified compensation plans	20			20	19			19
Total assets	$ 20	$ 286	$ 58	$ 364	$ 19	$ 974	$ 103	$ 1,096

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	December 31, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Liabilities								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ (42)	$	$ (42)	$	$ (45)	$	$ (45)
Other natural gas derivatives		(153)	(133)	(286)		(255)	(186)	(441)
Power-related derivatives			(386)	(386)			(510)	(510)
Interest rate derivatives		(17)		(17)		(21)		(21)
Other			(31)	(31)			(55)	(55)
Total liabilities	$	(212)	(550)	(762)	$	(321)	(751)	(1,072)
Total	$ 20	$ 74	$ (492)	$ (398)	$ 19	$ 653	$ (648)	$ 24

The following table presents the changes in our financial assets and liabilities included in Level 3 for the year ended December 31, 2009 (in millions):

	Change in Fair	Change in Fair	Change in Fair Value Reflected