EL PASO CORP/DE
Form 10-K
February 27, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ________ to ________ .

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (713) 420-2600

Internet Website: www.elpaso.com

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

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

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

None

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

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

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 x No ¨.

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 x No ¨.

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

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, 2011, 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: $15,556,156,330.

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 20, 2012: 772,860,126

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 2012 Annual Meeting of Stockholders are incorporated by reference into Part III of this report or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

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EL PASO CORPORATION

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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
Boe	=	barrel of oil equivalent
LNG	=	liquefied natural gas
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
Mcfe	=	thousand cubic feet of natural gas equivalents
MMBtu	=	million British thermal units
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
GWh	=	thousand megawatt hours
GW	=	gigawatts
NGL	=	natural gas liquids
TBtu	=	trillion British thermal units
Tcfe	=	trillion cubic feet of natural gas equivalents

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

When we refer to us , we , our , ours , the Company , or El Paso , we are describing El Paso Corporation and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

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.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our Corporate and other activities include our general and administrative functions, and other miscellaneous businesses, including our midstream business. For a further discussion of our business segments, see below and in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

On October 16, 2011, we announced a definitive merger agreement with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that valued El Paso at approximately $38 billion (based on the KMI stock price at that date), including the assumption of debt. Upon the merger, El Paso shareholders will receive a combination of Class P shares of common stock of KMI, common stock purchase warrants of KMI and cash. Each share of El Paso common stock (excluding shares held by El Paso in treasury and any shares held by KMI or its subsidiaries or El Paso and dissenting shares in accordance with Delaware law), will, at the effective time of the merger, be converted into the right to receive, at the election of the holder but subject to pro-ration with respect to the stock and cash portion so that approximately 57 percent of the aggregate merger consideration (excluding the warrants) is paid in cash and approximately 43 percent (excluding the warrants) is paid in Class P common stock of KMI, par value $0.01 per share (the KMI Class P Common Stock): (i) 0.9635 of a share of KMI Class P Common Stock and 0.640 of a common stock purchase warrant of KMI (a KMI Warrant) (ii) $25.91 in cash without interest and 0.640 of a KMI Warrant or (iii) 0.4187 of a share of KMI Class P Common Stock, $14.65 in cash without interest and 0.640 of a KMI Warrant. Each KMI Warrant will entitle its holder to purchase one share of KMI Class P Common Stock at an exercise price of $40.00 per share, subject to certain adjustments, at any time during the five-year period following the closing of the merger.

The merger agreement includes customary representations, warranties and covenants, and specific agreements relating to (i) the conduct of each of El Paso s and KMI s respective businesses between the date of the signing of the merger agreement and the closing of the merger transactions and (ii) the efforts of the parties to cause the merger transactions to be completed. In addition to certain other covenants, we have agreed not to encourage, solicit, initiate or facilitate any takeover proposal from a third party or enter into any agreement, arrangement or understanding requiring us to abandon, terminate or fail to consummate the merger and related transactions. The merger agreement contains certain termination rights for both El Paso and KMI and further provides that, upon termination of the merger agreement, under certain circumstances, El Paso may be required to pay KMI a termination fee equal to $650 million or, in certain other circumstances, El Paso may be required to reimburse KMI for its expenses up to $20 million and certain financing related expenses.

Under the terms of the merger agreement, we have agreed to conduct our business in the ordinary course and in all material respects in substantially the same manner as conducted prior to the date of the merger agreement, subject to certain conditions, restrictions and thresholds including, but not limited to, our ability to (i) commit to capital expenditures above our current capital budgets (ii) acquire, invest in, or dispose of any material properties, assets, or equity interests as defined in the merger agreement (iii) incur new debt, refinance, or guarantee any debt or borrowed money, (iv) enter into, terminate, or amend certain material contracts, (v) issue, grant, sell, or redeem new El Paso capital stock or stock-based compensation awards and/or pay dividends in excess of $0.01/share, among other limitations.

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The merger agreement has been approved by each of our and KMI s board of directors. The completion of the merger is subject to satisfaction or waiver of certain closing conditions including, among others, customary regulatory approvals, approval by our stockholders and approval of the issuance of KMI stock and warrants by KMI s stockholders. A voting agreement has been executed by certain stockholders of KMI, holding approximately 75 percent of the voting power of KMI, in which such stockholders have agreed to vote in favor of the merger and the issuance. Additional information regarding the proposed transactions and the terms and conditions of the merger agreement, voting agreement and other related agreements is set forth in our Current Report on Form 8-K, filed on October 17, 2011 and El Paso s proxy statement filed by Kinder Morgan, Inc. on November 10, 2011, (as amended on December 14, 2011 and January 3, 2012 and the prospectus filed January 31, 2012) in connection with the proposed merger transaction.

In conjunction with the merger, KMI announced that they intend to sell our exploration and production assets. On February 24, 2012, we entered into a purchase and sale agreement to sell all of our exploration and production assets to an affiliate of Apollo Global Management, LLC (Apollo) and certain other parties for $7.15 billion subject to certain adjustments for items such as contributions or distributions, incurrence of debt and title defects. The sale is contemplated by the merger agreement with KMI. The closing of the sale is conditioned upon the closing of the transactions contemplated by the merger agreement with KMI. Both transactions are expected to be completed in the second quarter of 2012. The purchase and sale agreement contains customary representations and warranties relating to the exploration and production assets and operations. Additionally, El Paso has entered into a performance guarantee in favor of Apollo, under which we guarantee the performance of all of our seller subsidiaries obligations under the purchase and sale agreement. Pursuant to the merger agreement with KMI, KMI is required to indemnify us from any and all cost incurred by us arising from or relating to the sale of the exploration and production assets. Upon completion of the sale, the exploration and production business will be reflected as a discontinued operation in our financial statements.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through eight wholly or partially owned pipeline systems and equity interests in three transmission systems. These systems consist of approximately 44,200 miles of pipe that connect the nation s principal natural gas supply regions to five major 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 Mexico. Our Pipelines segment also includes our ownership of storage capacity through our transmission systems, three underground natural gas storage facilities and two LNG receiving terminals. We provide approximately 240 Bcf of storage capacity and our LNG receiving terminals have a peak sendout capacity of 3.3 Bcf/d.

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

- focusing on customer service;
- developing growth projects in our market and supply areas;
- maintaining 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:

Transmission System	Supply and Market Region	As of December 31, 2011 Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[(1)] 2011	2010 (BBtu/d)	2009
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	13,900[(2)]	7,549[(2)]	93[(3)]	6,267[(2)]	5,081	4,614
El Paso Natural Gas (EPNG)	Extends from the San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650[(4)]	44	3,109	3,356	3,937
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[(5)]		377	421	379
Cheyenne Plains Gas Pipeline (CPG)	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	934		495	751	841

(1) Includes throughput transported on behalf of affiliates.
(2) Includes TGP 300 Line expansion project which was placed in service in November 2011.
(3) Includes 29 Bcf of storage capacity from Bear Creek Storage Company, L.L.C. (Bear Creek) which is owned equally by TGP and Southern Natural Gas (SNG).
(4) Reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.
(5) Reflects east to west flow capacity.

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Transmission System	Supply and Market Region	As of December 31, 2011 Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2011	2010 (BBtu/d)	2009
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.	52[2]	4,300	4,592	38[3]	2,128	2,131	2,299
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.	44[2]	7,600	3,896	60[4]	2,463	2,505	2,322
Wyoming Interstate (WIC)	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	44[2]	800	3,538		2,482	2,561	2,652
Elba Express	Extends from the Elba Island LNG terminal near Savannah, Georgia to the Transco pipeline in Hart County, Georgia and Anderson County, South Carolina. Also connected with SNG and directly connected to various power plants in Georgia.	44[2]	200	945		[5]	[5]	
Florida Gas Transmission (FGT)[6]	Extends from south Texas to South Florida.	50	5,500[6]	3,074[6]		2,368[6]	2,288	2,250
Ruby Pipeline[7]	Extends from Wyoming to Oregon providing natural gas supplies from the major Rocky Mountain basins to consumers in California, Nevada, and the Pacific Northwest.	50	680	1,490		792		

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

(2) At December 31, 2011, our master limited partnership, El Paso Pipeline Partners, L.P. (EPB), owns (i) 100 percent of SNG, WIC, Elba Express, and SLNG and (ii) an 86 percent interest in CIG. As of December 31, 2011, our ownership interest in EPB is 44 percent, including our 2 percent general partner interest. The ownership percentages shown above reflect both direct ownership of these systems and indirect ownership though our limited and general partner interests in EPB.

(3) Includes 7 Bcf of storage capacity from Totem Gas Storage facility (Totem) which is owned by WYCO Development L.L.C. (WYCO), our 50 percent equity investee.

(4) Includes 29 Bcf of storage capacity from Bear Creek which SNG owns equally with TGP.

(5) This system was placed in service in March 2010 and although capacity is under contract, the average volumes transported during 2011 and 2010 were not material.

(6) This system is operated by Southern Union Company and we have a 50 percent equity interest in Citrus Corp. (Citrus), which owns this system. An expansion of FGT of 483 miles of pipeline loops, laterals and mainlines was placed into service in April 2011.

(7) We have a 50 percent equity interest in this system which was placed in service in July 2011 and is jointly owned by Global Infrastructure Partners (GIP). Average throughput for 2011 represents volumes transported beginning with July 2011 in service.

WYCO Joint Venture. We own a 50 percent interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). WYCO owns the 164 mile High Plains pipeline and Totem storage facilities located in Northeast Colorado which are operated by us. The Totem storage facility consists of a 7 Bcf natural gas storage field that services and interconnects with the High Plains pipeline. 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 leased by us.

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 underground natural gas storage facilities:

	As of December 31, 2011		
Storage Facility	**Ownership Interest (Percent)**	**Storage Capacity[4] (Bcf)**	**Location**
Bear Creek	72[1]	58[2]	Louisiana
Totem	26[1]	7[3]	Colorado
Young Gas Storage	48	6	Colorado

(1) Includes direct ownership and indirect ownership through our proportionate interest in our master limited partnership, EPB.
(2) Approximately 29 Bcf is contracted to each SNG and TGP.
(3) Maximum withdrawal rate of 200 MMcf/d and a maximum injection rate of 100 MMcf/d.
(4) Amount is not adjusted for our ownership interest in these facilities.

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LNG Facilities

Southern LNG Company, L.L.C. (SLNG). Through our ownership interest in EPB, we own a 44 percent interest in SLNG which owns an LNG receiving terminal located on Elba Island, near Savannah, Georgia, with a peak sendout capacity of 1.8 Bcf/d and a storage capacity of 11.5 Bcfe. The capacity at the terminal is contracted with BG LNG Services, LLC and Shell NA LNG LLC. The Elba Island LNG terminal is directly connected to three interstate pipelines and indirectly connected to two others, and thus is readily accessible to the southeast and mid-Atlantic markets. SNG operates the Elba Island LNG terminal. The firm SLNG service agreements are supported by parent guarantees from BG and Shell that secure the timely performance of the obligations of those agreements.

Southern Gulf LNG Company, L.L.C. We also have a 50 percent interest in the Gulf LNG Clean Energy Project (GLNG), which owns an LNG receiving terminal in Pascagoula, Mississippi with a peak sendout capacity of 1.5 Bcf/d and a storage capacity of 6.6. Bcfe that was placed in service in October 2011. The terminal is fully subscribed under long term contracts and is directly connected by a five mile pipeline to four interstate pipelines and extends to a natural gas processing plant.

Markets and Competition

Our Pipelines segment provides natural gas services to a variety of customers, including natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies. We provide transportation and storage services in both our natural gas supply and market areas. 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 natural gas industry has experienced a major shift from conventional supply sources to unconventional sources, such as shales. In addition, the increase in oil prices has led to increased production of natural gas found in association with the production of oil. This shift has impacted supply patterns, flows and rates that can be charged on pipeline systems. The impact will vary among pipelines according to the location and the number of competitors attached to these new supply sources. Certain of our pipelines are connected to several major shale formations: the Haynesville Shale in northern Louisiana and Texas, the Eagle Ford Shale in south Texas and the Marcellus Shale in Pennsylvania. Gas from these sources could continue to increasingly displace receipts over time from traditional sources such as south Texas and the Gulf of Mexico on our system. Future production growth in the dry gas portion of these plays could be impacted by producer decisions to shift their activity to projects in different regions that contain liquids and offer a better economic return. A potential loss of dry gas volumes in the Marcellus Shale, however, may be offset by increased drilling in the liquid rich portion of the play as well as increased production from the Utica. An example of growing activity in a liquid rich play is occurring in the Eagle Ford Shale in South Texas, which could become a major source of supply into two of our systems.

Another change in the supply patterns is the reduction in imports from Canada. This decrease has been the result of continuing declines in conventional Canadian production coupled with increasing demand in Canada. On the Southern border, exports to Mexico are increasing and may increase further over time as demand growth exceeds production growth in that country. In addition to these trends in Canada and Mexico, imports of LNG to the U.S. have been declining over the last several years in response to increased U.S. shale gas production which has resulted in a decline in U.S. natural gas prices relative to gas prices in Europe and Asia. The projected gas price disparity between U.S. and European/Asian markets suggests that North America could change from a net importer of LNG to a net exporter of LNG before the end of this decade. All of the aforementioned factors have led to increased demand for domestic U.S. supplies and related transportation services over the last several years, a trend which is likely to continue.

Electric power generation has been the source of most of the demand growth for natural gas over the last 10 years, and this trend is expected to continue. The growth of natural gas in this sector is influenced by competition with coal and economic growth. Short-term market shifts have been driven by relative electricity generation costs of coal-fired plants versus gas-fired plants. A long-term market shift in the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources. Industrial demand has also grown recently with the economic recovery and low natural gas price environment, and this sector offers an opportunity for continued growth. In addition, a potential new and significant demand market for North American natural gas production is for LNG exports to Europe and Asia. Several Gulf Coast projects have received approval from the U.S. Department of Energy to export LNG to global markets beginning in the second half of this decade.

For a further discussion of factors impacting our markets and competition, See Item 1A, Risk Factors.

Our existing transportation and storage contracts expire 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. Although we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariffs, we frequently 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 firm contracts is approximately six years. The table below shows the years of expiration of our firm transportation contracts as of December 31, 2011 for our wholly and majority owned systems. For additional information on our pipeline firm transportation contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

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The following table details information related to our pipeline systems and certain other facilities as of December 31, 2011. Firm customers reserve capacity on our pipeline system, storage facilities or LNG receiving terminals 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 420 firm and interruptible customers.	Approximately 480 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, the Marcellus shale and from the Canadian border.
Major Customer:		
National Grid USA and subsidiaries		
(481 BBtu/d)	Expire in 2012-2014.	
(285 BBtu/d)	Expire in 2015-2029.	
EPNG		
Approximately 130 firm and interruptible customers.	Approximately 180 firm transportation contracts. Weighted average remaining contract term of approximately three years.	EPNG faces competition in the west and southwest from other existing 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 gas imported into California from Canada and from an LNG facility located in northern Mexico.
Major Customers:		
Southern California Gas Company (SoCal)		
(306 BBtu/d)	Expires in 2012.	
(207 BBtu/d)	Expire in 2013-2014.	
ConocoPhillips Company		
(492 BBtu/d)	Expires in 2012.	
MGI Supply, Ltd		
(350 BBtu/d)	Expires in 2012.	
Southwest Gas Corporation		
(240 BBtu/d)	Expire in 2013-2018.	

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Customer Information	Contract Information	Competition
MPC		
Five firm and interruptible customers.	Three firm transportation contracts. Weighted average remaining contract term of approximately four years.	MPC faces competition from other existing 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 an LNG facility located in northern Mexico.
Major Customer: EPNG (510 BBtu/d)	Expires in 2015.	
CPG		
Approximately 30 firm and interruptible customers.	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately five 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, Inc. and subsidiaries (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 230 firm and interruptible customers.	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately six years.	SNG faces competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on SNG s system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal, fuel oil and nuclear. SNG s four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. SNG also 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:		
AGL Resources Inc. and subsidiaries		
(995 BBtu/d)	Expire in 2013-2015.	
(84 BBtu/d)	Expires in 2024.	
Southern Company and subsidiaries		
(31 BBtu/d)	Expire in 2013-2014.	
(390 BBtu/d)	Expire in 2017-2018.	
(375 BBtu/d)	Expires in 2032.	
Alabama Gas Corporation		
(352 BBtu/d)	Expire in 2013-2014.	
SCANA Corporation and subsidiaries		
(315 BBtu/d)	Expire in 2013-2019.	

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Customer Information	Contract Information	Competition
CIG		
Approximately 100 firm and interruptible customers.	Approximately 160 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 and subsidiary		
(913 BBtu/d)	Expire in 2012-2019.	
(874 BBtu/d)	Expire in 2025-2029.	
(200 BBtu/d)	Expires in 2040.	
Williams Gas Marketing, Inc.		
(385 BBtu/d)	Expire in 2013-2014.	
Colorado Springs Utilities		
(331 BBtu/d)	Expire in 2012-2023.	

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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 six 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.		
(353 BBtu/d)	Expire in 2013-2015.	
(420 BBtu/d)	Expire in 2017-2018.	
(613 BBtu/d)	Expire in 2019-2021.	
Anadarko Petroleum Corporation and subsidiaries		
(223 BBtu/d)	Expire in 2013-2015.	
(406 BBtu/d)	Expire in 2016-2018.	
(665 BBtu/d)	Expire in 2020-2023.	
Elba Express		
Eight firm and interruptible customers.	One firm transportation contract. Remaining contract term of approximately 28 years.	Elba Express pipeline is primarily served by gas volumes from SLNG s Elba Island LNG terminal and consequently it competes for gas supply into its system within the global LNG market in order to provide transportation to downstream markets in the southeast, mid-Atlantic and northeast.
Major Customer:		
Shell NA LNG LLC		
(965 BBtu/d)	Expires in 2040.	
SLNG		
Two firm customers.	Two firm storage contracts. Weighted average remaining contract term of approximately 21 years.	SLNG competes with other U.S. LNG terminal facilities for global LNG supplies.
Major Customers:		
BG LNG Services, LLC		
(630 MMcf/d)	Expires in 2027.	
Shell NA LNG LLC		
(945 MMcf/d)	Expire in 2035 - 2036.	

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Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. 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.

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Exploration and Production Segment

Business Strategy. The strategy of our exploration and production business is to generate competitive returns from our capital investment programs while growing proved reserves, production volumes and future drilling opportunities while optimizing our existing asset base. The key elements of this strategy are:

- Generating future drilling opportunities by focusing on repeatable, low-risk plays;
- Adding assets that fit our competencies and divesting of assets that no longer meet these criteria;
- Improving capital and operating efficiency to maximize returns; and
- Funding our capital program to optimize growth and returns while maintaining financial strength and flexibility.

As previously discussed, in October 2011 we announced a merger with KMI, whereby they will acquire El Paso and ultimately plan to sell our exploration and production business.

Asset Base. The fastest growing portion of our asset base is in unconventional reservoirs, primarily oil and natural gas shale plays. Approximately 85 percent of our current production and approximately 70 percent of our proved reserve base is natural gas, a large percentage of which is held by production, which represents a valuable option as natural gas prices improve in the future. Over the last two years we have developed oil and liquids rich drilling programs through the addition of the Eagle Ford and Wolfcamp shales, the ongoing development of our Altamont Field and the recent addition of our Louisiana Wilcox program. This has allowed us to take advantage of higher oil prices and has significantly impacted cash flow generation. The development of these assets has continued, and will continue, to result in accelerated growth in oil production, proved reserves and associated revenues. In 2011, 38 percent of our physical sales were derived from oil, condensate and NGLs. Our capital expenditures related to oil and liquids rich programs for 2011 comprised 61 percent of our total capital.

Core Programs. Over the past four years our focus has been on areas where we have organizational competencies that offer repeatable drilling programs with the objective of reducing development costs. At the same time, we have improved the quality and depth of our drilling opportunities. During 2011, our principal focus was in four core areas: the Haynesville Shale, the Eagle Ford Shale, the Wolfcamp Shale and the Altamont fractured tight sands. Our initial execution of this strategy was in the Haynesville Shale where we had acreage held by production as a result of historical development activities in the east Texas and north Louisiana areas. We acquired additional leasehold interests through an acquisition in 2007. In the Haynesville Shale, we piloted horizontal drill wells, experimenting with different horizontal lateral lengths and fracture stimulation staging, with the objective of delivering optimal capital efficiency, finding costs and returns. The success of the Haynesville program was transferred to our Eagle Ford Shale program through growing competencies in horizontal shale drilling and completion techniques and in improved knowledge transfer between our operating divisions.

We were an early and low-cost entrant in the Eagle Ford Shale, acquiring our interests through leasehold acquisitions. Overall, we own approximately 157,000 net acres in our north, central and south Eagle Ford areas where approximately 77,000 net acres are under development in our central Eagle Ford area. During 2010 and 2011, we improved our efficiency and productivity of our development program, reducing per-well capital costs by 16 percent and drilling cycle time by more than 35 percent year over year. Most of our wells have had initial production rates that range from 600 to over 1,000 Boe/d, and our oil production in this area has grown significantly since the beginning of 2011. As a result, we have turned the Eagle Ford Shale into one of our key development areas, which has increased the percentage of our oil reserves and production.

In late 2010, we established a new major oil shale position by successfully leasing approximately 138,000 net acres in the Wolfcamp Shale. Again, we used a similar technical assessment approach and were able to be an early and low-cost entrant into the play. In 2011, we advanced our understanding of this area using the same approach and techniques that have allowed us to be successful in the Haynesville Shale and Eagle Ford Shale. As a result, in late 2011 we completed a 7,500 foot lateral well with 25 stages that tested at an initial production rate of 1,369 Boe/d.

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We have also reengineered an existing oil asset; the Altamont Field in Utah. Altamont was initially developed in the 1970s, and we are applying modern drilling and stimulation technology to develop this tight-sand field that, on a field wide basis, has only produced about 10 percent of the estimated oil in place. We have enhanced the value of this field by infill drilling, which we received regulatory approval for in 2008. Altamont is an asset that offers significant future oil production growth opportunities with a significant number of future drilling opportunities. Since the majority of the acreage is held by production, we have greater flexibility to choose our pace of development such that we can optimize growth and technical understanding of this prolific oil area.

Operations. In the U.S., we currently operate through three divisions: Central, Western and Southern. During 2011, we focused our activities on our core programs. Over the past few years, we have high-graded our future drilling opportunities through producing property acquisitions, acreage acquisitions and the sale of producing properties that tended to be late in life and without meaningful future drilling opportunities. As a result, our drilling programs are now lower risk, more concentrated, more domestic, more focused on oil and more profitable.

Internationally, our portfolio consists of producing fields along with exploration and development projects in offshore Brazil and exploration projects in Egypt s Western Desert. Our Brazilian operations are in the Camamu, Espirito Santo and Potiguar basins and our Egyptian operations are in the South Mariut and the South Alamein blocks.

The following table provides summary data of each of our areas of operation as of December 31, 2011:

	Estimated Net Proved Reserves		Average	
	Bcfe	% Proved Developed	Production MMcfe/d	Net Acres
United States				
Central				
Haynesville Shale	903	34%	265	41,000
Other Central	589	79%	157	737,000
Western				
Altamont	551	37%	55	176,000
Other Western	559	68%	99	785,000
Southern				
Eagle Ford Shale	642	18%	40	157,000
Wolfcamp Shale	148	12%	3	138,000
Other Southern	326	94%	124	314,000
International				
Brazil	95	100%	34	132,000
Egypt		%		774,000
Total Consolidated	3,813	50%	777	3,254,000
Unconsolidated Affiliate(1)	174	86%	61	
Total Combined	3,987	51%	838	

(1) Amounts represent our approximate 49 percent equity interest in Four Star Oil & Gas Company (Four Star).

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U.S.

Central. The Central division includes operations that have largely been focused on shale gas, primarily the Haynesville in north Louisiana with New Albany Shale production in Indiana, tight gas sands production in north Louisiana and east Texas, coal bed methane production in the Black Warrior Basin of Alabama and in the Arkoma Basin of Oklahoma and conventional oil production in south Louisiana from the Louisiana Wilcox program. The Central division operations have generally been characterized by lower development costs, higher drilling success rates and longer reserve lives. We have increased our drilling prospects in this division and have grown production in this area for five consecutive years. During 2011, we invested $585 million on capital projects and production averaged 422 MMcfe/d in the Central division.

Haynesville Shale

In 2011, the Haynesville Shale was our core program in the Central division. It is located in northwest Louisiana and east Texas. Our operations are in the Holly, Bethany Longstreet and Logansport fields. A majority of our acreage is located in a high deliverability part of the play. During 2011, we operated an average of four drilling rigs and we invested $409 million in capital expenditures in our Haynesville Shale. Average production for the year ended December 31, 2011 was 265 MMcfe/d compared to 143 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Haynesville Shale included:

- 41,000 total net acres, including approximately 29,000 undeveloped net acres
- 903 Bcfe of estimated net proved reserves
- 93 net producing wells

Other Central:

Area	Description	Net Acres	2011 Capital Investment (In millions)	Average Production (MMcfe/d)
Arklatex / Unconventional	Our Arklatex land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. Our operations are in the Bear Creek, Vacherie Dome, Holly, Bethany, Longstreet and Bald Prairie fields. Additionally we have shallow coal bed methane producing areas in the Black Warrior Basin in Alabama and the Arkoma Basin in Oklahoma. Our production is from vertical wells in Alabama and horizontal wells in the Hartshorne Coals in Oklahoma. We have high average working interests and long life reserves in these areas. In addition, we have a 50 percent average working interest covering approximately 46,000 net acres of coal bed methane production operated by Black Warrior Methane Corporation in the Brookwood Field. We also have approximately 200,000 net acres in the Illinois Basin. We are the operator of these properties and have a 95 percent working interest. During 2011, we sold oil and natural gas properties located in the Minden and Blue Creek fields for approximately $204 million.	554,000	$28	147
Louisiana Wilcox	Our activity is located primarily in Beauregard Parish, Louisiana and is focused on the Wilcox Sands. This is a conventional vertical well play utilizing 3-D seismic to help with location selection. The Wilcox produces both oil and natural gas from a series of completed sands.	183,000	$ 148	10

Western. The Western division includes operations that are primarily focused on oil and natural gas production from fractured tight sands, coal bed methane and shale gas. We have a large number of drilling prospects in this division. During 2011, we invested $205 million on capital projects and production averaged 154 MMcfe/d in the Western division.

Altamont

The Altamont Field is our core program in the Western division. Our focus has been on drilling vertical fractured wells through fractured tight oil sands in the Uintah Basin located in Utah. We have gained operational efficiencies as we have developed the field. During 2011, we operated an average of approximately three drilling rigs and we invested $173 million in capital expenditures in our Altamont area. Average production for the year ended December 31, 2011 was 55 MMcfe/d compared to 51 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Altamont area include:

176,000 total net acres, including approximately 56,000 undeveloped net acres

551 Bcfe of estimated net proved reserves

301 net producing wells

Other Western:

Area	Description	Net Acres	2011 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.	606,000	$30	79
Rocky Mountains (Rockies)	Non-operated working interest in the County Line coal bed methane property in Wyoming with additional non-production acreage in Colorado, Wyoming, North Dakota and Utah. During 2011, we sold our operated oil and natural gas properties located in the Powder River Basin in Wyoming for approximately $346 million.	179,000	$ 2	20

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Southern. In the Southern division our focus has been primarily on developing and exploring for oil and natural gas in unconventional shales and tight gas sands in south and west Texas. These opportunities have been characterized by lower risk, longer life production profiles. We also have operations in Gulf of Mexico focused on conventional reservoirs characterized by relatively high initial production rates, resulting in higher near-term cash flows and high decline rates. During 2011, we invested $807 million on capital projects and production averaged 167 MMcfe/d in the Southern division.

Eagle Ford Shale

The Eagle Ford Shale is one of the core programs in our Southern division, located in LaSalle, Webb, Atascosa and Dimmit counties. Our 2008 leasing efforts began early in the play, resulting in a relatively low per acre entry cost. The Eagle Ford oil and volatile oil programs are currently the most economic of our portfolio with approximately 60 percent of our total net acres located in this area. During 2011, we operated an average of three drilling rigs and we invested $626 million in capital expenditures in our Eagle Ford Shale. In late 2011, we also sold oil and natural gas properties located in the Frio county area for approximately $26 million. Average net production for the year ended December 31, 2011 was 40 MMcfe/d compared to 6 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Eagle Ford Shale include:

- 157,000 total net acres, including approximately 151,000 undeveloped net acres
- 642 Bcfe of estimated net proved reserves
- 64 net producing wells

Wolfcamp Shale

The Wolfcamp Shale is the second core program in our Southern division. It is located in the Permian Basin in Reagan, Crockett, Upton and Irion counties in Texas. We have grown our position, starting in 2010 to approximately 138,000 net acres. During 2011, we operated an average of two drilling rigs and we invested $163 million in capital expenditures in our Wolfcamp Shale. Average net production for the year ended December 31, 2011 was 3 MMcfe/d. As of December 31, 2011, our properties in the Wolfcamp Shale include:

- 138,000 total net acres, including approximately 135,000 undeveloped net acres
- 148 Bcfe of estimated net proved reserves
- 14 net producing wells

Other Southern:

Area	Description	Net Acres	2011 Capital Investment (In millions)	Average Production (MMcfe/d)
Texas Gulf Coast /Gulf of Mexico	The Wilcox assets include the Renger, Dry Hollow, Brushy Creek and Speaks fields located in Lavaca County, and the Graceland Field located in Colorado County. The Vicksburg/Frio area with concentrated and contiguous assets in the Jeffress and Monte Christo fields primarily in Hidalgo County. This area also includes assets in the Alvarado and	314,000	$ 18	124

Kelsey fields in Starr and Brooks Counties. 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. The Gulf of Mexico area includes interests in 69 Blocks south of the Louisiana, Texas and Alabama shoreline focused on deep (greater than 12,000 feet) oil and natural gas reserves in relatively shallow water depths (less than 400 feet). In these areas, we have licensed over 13,500 square miles of three dimensional (3D) seismic data onshore and over 62,000 square miles of 3D seismic data offshore.

Unconsolidated Affiliate *Four Star.* We have an approximate 49 percent equity interest in Four Star. Four Star operates in the San Juan, Permian, Hugoton and South Alabama basins and in the Gulf of Mexico. Production is from conventional and coal bed methane assets in several basins. During 2011, our equity interest in Four Star s daily equivalent natural gas production averaged approximately 61 MMcfe/d.

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International

Brazil. Our Brazilian operations cover approximately 132,000 net acres in Camamu, Espirito Santo and Potiguar basins located offshore Brazil. During 2011, we invested $19 million in capital projects in Brazil and production averaged 34 MMcfe/d. As of December 31, 2011 we have total oil and natural gas capitalized costs of approximately $205 million, of which $8 million are unevaluated capitalized costs. Our operations in each basin are described below:

Camamu Basin. We own a 100 percent working interest in two development areas, the Pinauna and Camarao fields. During 2011, we were informed that our environmental permit request for the Pinauna Field in the Camamu Basin was denied by the Brazilian environmental regulatory agency. As a result, we released $94 million of unevaluated capitalized costs related to this field into the Brazilian full cost pool. We have filed an appeal and are awaiting a response.

We own a 20 percent interest in two additional blocks in the Camamu Basin, CAL-M-312 and CAL-M-372. During 2011, we relinquished our 18 percent working interest in the BM-CAL-5 block which is owned by Petrobras, Brazil s state-owned energy company.

Espirito Santo Basin. We own an approximate 24 percent working interest in the Camarupim Field. We have four wells producing in the field, and production in the Camarupim Field averaged approximately 27 MMcfe/d in 2011. We also own a 35 percent working interest in two areas that are under plans of evaluation, originating from the ES-5 block, which are operated by Petrobras.

During 2011 we also released approximately $86 million of unevaluated capitalized costs related to the ES-5 block upon the completion of our evaluation of exploratory wells drilled in 2009 and 2010 without any additions to our proved reserves.

Potiguar Basin. We own a 35 percent working interest in the Pescada-Arabaiana fields. Our production from these fields averaged approximately 7 MMcfe/d in 2011.

Egypt. As of December 31, 2011, our Egyptian operations cover approximately 774,000 net acres in two blocks located onshore in Egypt s Western Desert. During 2011, we invested $8 million in capital projects in Egypt. We own a 60 percent working interest in the South Mariut block, which contains approximately 497,000 net acres and a 50 percent working interest in the South Alamein block, which contains approximately 277,000 net acres. In 2011, we relinquished our 40 percent working interest in the Tanta block. Due to political unrest in Egypt during 2011, we experienced a delay in obtaining governmental approval of a new partner in our South Alamein block and postponed drilling in South Mariut. We expect these matters to be resolved in 2012 and we continue to evaluate the commerciality of these areas. As of December 31, 2011 we have total capitalized costs in Egypt of approximately $74 million, all of which are unevaluated.

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Oil and Natural Gas Properties

Oil and Condensate, Natural Gas and NGL Reserves and Production

The table below presents information about our estimated proved reserves as of December 31, 2011. These reserves are based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of oil and natural gas that are ultimately recovered. The risks and uncertainties associated with estimating proved oil and natural gas 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, 2011.

	Net Proved Reserves					2011
	Natural Gas (MMcf)	**Oil/Condensate (MBbls)**	**NGL (MBbls)**	**Total (MMcfe)**	**(Percent)**	**Production (MMcfe)**
Reserves and Production by Division						
Consolidated:						
Proved						
U.S.						
Central	1,475,723	2,707		1,491,965	37%	153,862
Western	700,298	68,288		1,110,026	28%	56,410
Southern	389,845	106,806	14,245	1,116,151	28%	60,885
Total	2,565,866	177,801	14,245	3,718,142	93%	271,157
Brazil	81,325	2,269		94,942	3%	12,539
Total Consolidated	2,647,191	180,070	14,245	3,813,084	96%	283,696
Unconsolidated Affiliate[1]	134,713	1,569	4,908	173,574	4%	22,052
Total Combined	2,781,904	181,639	19,153	3,986,658	100%	305,748
Reserves by Classification						
Consolidated:						
Proved Developed						
U.S.	1,488,045	46,797	5,168	1,799,831	47%	
Brazil	81,325	2,269		94,942	3%	
Total	1,569,370	49,066	5,168	1,894,773[2]	50%	
Proved Undeveloped						
U.S.	1,077,821	131,004	9,077	1,918,311	50%	
Brazil					%	
Total	1,077,821	131,004	9,077	1,918,311	50%	
Total Consolidated	2,647,191	180,070	14,245	3,813,084[2]	100%	
Unconsolidated Affiliate[1]:						
Proved Developed	116,029	1,520	4,066	149,540	86%	
Proved Undeveloped	18,684	49	842	24,034	14%	
Total Unconsolidated Affiliate[1]	134,713	1,569	4,908	173,574	100%	
Total Combined	2,781,904	181,639	19,153	3,986,658	100%	

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

(2) Includes 1,550 Bcfe of proved developed producing reserves representing 41 percent of consolidated proved reserves and 345 Bcfe of proved developed non-producing reserves representing 9 percent of consolidated proved reserves at December 31, 2011.

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, 2011.

	Net Proved Reserves (MMcfe)
As Reported	
Consolidated	3,813,084
Unconsolidated Affiliate	173,574
Total Combined	3,986,658
10 percent increase in commodity prices(1)	
Consolidated	3,836,145
Unconsolidated Affiliate	175,991
Total Combined	4,012,136
10 percent decrease in commodity prices(1)	
Consolidated	3,614,145
Unconsolidated Affiliate	170,007
Total Combined	3,784,152

(1) Based on the first day 12-month average U.S prices of $96.19 per barrel of oil and $4.12 per MMBtu of natural gas used to determine proved reserves at December 31, 2011.

Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. A sustained period of low domestic natural gas prices will over time result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our proved reserves.

El Paso employs a technical staff of engineers and geoscientists to perform technical analysis of each undeveloped location. The staff uses industry accepted practices to estimate, with reasonable certainty, the economically producible oil and natural gas. The practices for estimating hydrocarbons in place include, but are not limited to; mapping, seismic interpretation of two-dimensional and/or three-dimensional data, core analysis, mechanical properties of formations, thermal maturity, well logs of existing penetrations, correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare related to our investment in 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 more than 24 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 proved reserves prepared by us as of December 31, 2011. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our total proved reserves on a natural gas equivalent basis, representing 87 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, 2011. In connection with the audit of these proved reserves, Ryder Scott reviewed 87 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 91 percent of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10 percent of Ryder Scott s estimates. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the reserves audit by Ryder Scott has a B.S. degree in mechanical engineering. He is a Licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has more than 20 years of experience in petroleum reserves evaluation.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with

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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 Oil and Natural Gas Operations.

We currently have 1,474 undeveloped locations, of which 575 are in shales where we are actively developing reserves. The three shales are Haynesville, Eagle Ford and Wolfcamp. At this time we do not have a developed to undeveloped relationship that is beyond one adjacent offset to a productive well.

We assess our PUD reserves on a quarterly basis. At December 31, 2011, we had 1,918 Bcfe of consolidated PUD reserves representing an increase of 662 Bcfe of PUD reserves compared to December 31, 2010. During 2011, we added 939 Bcfe of PUD reserves primarily due to our drilling activities in the Haynesville Shale in our Central division and the Eagle Ford and Wolfcamp shales in our Southern division. We had 210 Bcfe of PUD reserves transferred to proved developed reserves and negative revisions of 11 Bcfe related to reserves older than five years as well as 20 Bcfe related to prices and performance. We divested 36 Bcfe PUD reserves from the sales of assets throughout the year in our Central, Southern and Western divisions.

We spent approximately $601 million, $199 million and $186 million, during 2011, 2010 and 2009, respectively, to convert approximately 17 percent or 210 Bcfe, 11 percent or 94 Bcfe and 11 percent or 69 Bcfe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2011 reserve report, the amounts estimated to be spent in 2012, 2013 and 2014 to develop our consolidated worldwide PUD reserves are $1,003 million, $1,009 million and $1,329 million, respectively. The upward trend in the amounts estimated to be spent to develop our PUD reserves is a result of our shift in capital focus to develop our core programs. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and commodity prices.

Of the 1,918 Bcfe of PUD reserves at December 31, 2011, we have 49 Bcfe of undeveloped reserves that are outside of our current five-year development plan in the Raton Basin located in northern New Mexico and southern Colorado. These reserves extend beyond the five-year development plan due to pace restrictions established by the surface owner which limits the number of wells drilled annually to a level significantly below the historical levels of wells drilled per year. Additionally, we own the mineral rights on the acreage in the Raton Basin which enables us to develop beyond the five-year window. We have historical and ongoing drilling and development activities in this area, including the drilling of 30 undeveloped locations in 2011 and a 30 to 50 well development program in 2013. There were no new PUD reserves booked to the Raton Basin in 2011, and the undeveloped reserves outside of our current five-year development plan represent less than five percent of the consolidated PUD reserves.

Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2011, (ii) our interest in oil and natural gas wells at December 31, 2011 and (iii) our exploratory and development wells drilled during the years 2009 through 2011. 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	312,754	224,473	679,524	553,276	992,278	777,749
Western	328,845	271,806	891,333	688,801	1,220,178	960,607
Southern	270,904	155,712	503,352	453,559	774,256	609,271
Total United States	912,503	651,991	2,074,209	1,695,636	2,986,712	2,347,627
Brazil	47,377	14,492	458,519	117,344	505,896	131,836
Egypt			1,382,856	774,195	1,382,856	774,195
Worldwide Total	959,880	666,483	3,915,584	2,587,175	4,875,464	3,253,658

(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.

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In the United States, our net developed acreage is concentrated primarily in New Mexico (19 percent), Utah (18 percent), the Gulf of Mexico (13 percent), Texas (12 percent), Louisiana (11 percent), Oklahoma (11 percent) and Alabama (8 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (26 percent), Texas (19 percent), Indiana (11 percent), Louisiana (10 percent), the Gulf of Mexico (9 percent) and Colorado (7 percent). Approximately 10 percent, 21 percent and 10 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012, 2013 and 2014, respectively. Approximately 6 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012. Approximately 13 percent and 27 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012 and 2013, respectively. We employ various techniques to manage the expiration of leases, including drilling the acreage ourselves prior to lease expiration, entering into farm-out agreements with other operators or extending lease terms.

	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2011[1]	
	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3][4]	Gross[2]	Net[3]
Productive Wells								
United States								
Central	3,047	1,942	10	7	3,057	1,949	17	10
Western	1,421	1,065	426	290	1,847	1,355	3	3
Southern	973	781	107	101	1,080	882	23	23
Total	5,441	3,788	543	398	5,984	4,186	43	36
Brazil	9	2	5	2	14	4		
Egypt							4	2
Worldwide Total	5,450	3,790	548	400	5,998	4,190	47	38

(1) Includes wells that were spud in 2011 or a prior year and have not been completed.
(2) Gross interest reflects the total wells we participated in, regardless of our ownership interest.
(3) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.
(4) At December 31, 2011, we operated 3,625 of the 4,190 net productive wells.

	Net Exploratory[1]			Net Development[1]		
	2011	2010	2009	2011	2010	2009
Wells Drilled						
United States						
Productive	87	35	61	95	55	69
Dry			2		2	2
Total	87	35	63	95	57	71
Brazil						
Productive						1
Dry	1					
Total	1					1
Egypt						
Productive						
Dry			2			

Total			2			
Worldwide						
Productive	87	35	61	95	55	70
Dry	1		4		2	2
Total	88	35	65	95	57	72

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

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 oil and natural gas that may ultimately be recovered.

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Net Production, Sales Prices, Transportation and Production Costs

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

	2011	2010	2009
Volumes:			
Consolidated Net Production Volumes			
United States			
Natural gas (MMcf)(1)	230,669	215,905	214,718
Oil and condensate (MBbls) (1)	5,680	4,363	3,978
NGL (MBbls) (1)	1,068	1,423	1,570
Total (MMcfe)	271,157	250,621	248,006
Brazil			
Natural gas (MMcf)	10,414	9,706	3,826
Oil and condensate (MBbls)	354	384	100
NGL (MBbls)			
Total (MMcfe)	12,539	12,010	4,426
Consolidated Worldwide			
Natural gas (MMcf)	241,083	225,611	218,544
Oil and condensate (MBbls)	6,034	4,747	4,078
NGL (MBbls)	1,068	1,423	1,570
Total (MMcfe)	283,696	262,631	252,432
Total (MMcfe/d)	777	720	691
Unconsolidated Affiliate Volumes(2)			
Natural gas (MMcf)	16,881	17,165	19,557
Oil and condensate (MBbls)	306	364	419
NGL (MBbls)	556	573	678
Total equivalent volumes (MMcfe)	22,052	22,787	26,139
MMcfe/d	61	62	72
Total Combined Volumes(2)			
Natural gas (MMcf)	257,964	242,776	238,101
Oil and condensate (MBbls)	6,340	5,111	4,497
NGL (MBbls)	1,624	1,996	2,248
Total equivalent volumes (MMcfe)	305,748	285,418	278,571
MMcfe/d	838	782	763
Consolidated Prices and Costs per Unit:			
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Physical sales	$ 3.91	$ 4.26	$ 3.78
Including financial derivative settlements(3)	$ 5.37	$ 5.71	$ 7.68
Brazil			
Physical sales	$ 6.94	$ 5.65	$ 4.84
Including financial derivative settlements(3)	$ 6.94	$ 4.93	$ 4.22
Worldwide			
Physical sales	$ 4.04	$ 4.32	$ 3.80
Including financial derivative settlements(3)	$ 5.44	$ 5.67	$ 7.62
Oil and Condensate Average Realized Sales Price ($/Bbl)			
United States			
Physical sales	$ 90.22	$ 72.37	$ 52.27
Including financial derivative settlements(3)	$ 88.98	$ 70.52	$ 96.44
Brazil			
Physical sales	$ 110.33	$ 78.02	$ 60.88
Including financial derivative settlements	$ 110.33	$ 78.02	$ 60.88
Worldwide			

Physical sales	$ 91.40	$ 72.83	$ 52.48
Including financial derivative settlements[3]	$ 90.23	$ 71.13	$ 95.57
NGL Average Realized Sales Price ($/Bbl)			
United States			

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Physical sales	$ 53.50	$ 42.38	$ 33.75
Brazil			
Physical sales	$	$	$
Worldwide			
Physical sales	$ 53.50	$ 42.38	$ 33.75
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.35	$ 0.31	$ 0.28
Oil and condensate ($/Bbl)	$ 0.06	$ 0.09	$ 0.06
NGL ($/Bbl)	$ 3.83	$ 3.16	$ 2.61
Worldwide			
Natural gas ($/Mcf)	$ 0.33	$ 0.30	$ 0.28
Oil and condensate and($/Bbl)	$ 0.06	$ 0.08	$ 0.06
NGL ($/Bbl)	$ 3.83	$ 3.16	$ 2.61
Average Production Costs (Lease Operating Expenses) ($/Mcfe)			
United States	$ 0.65	$ 0.62	$ 0.70
Brazil(4)	$ 3.29	$ 3.07	$ 5.19
Worldwide(4)	$ 0.77	$ 0.73	$ 0.78
Average Production Taxes ($/Mcfe)			
United States	$ 0.26	$ 0.21	$ 0.21
Brazil	$ 0.91	$ 0.73	$ 0.68
Worldwide	$ 0.28	$ 0.27	$ 0.22

(1) For the years ended December 31, 2011 and 2010, our Eagle Ford Field had natural gas volumes of 1,971 MMcf and 287 MMcf, oil and condensate volumes of 1,690 MMBbls and 177 MMBbls and NGL volumes of 207 MMBbls and 30 MMBbls, respectively. For the years ended December 31, 2011, 2010 and 2009, our Haynesville Holly Field, within the Central division, had natural gas volumes of 80,591 MMcf, 42,820 MMcf and 11,223 MMcf, and NGL volumes of 2 MMBbls, 2 MMBbls and less than 1 MMBbls, respectively. The Haynesville Holly Field had oil and condensate volumes of less than 1 MMBbls for the year ended December 31, 2011.

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

(3) We had no cash premiums related to oil derivatives settled during the years ended December 31, 2011, 2010 and 2009. Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2011 were $23 million. Had we included these premiums in our natural gas average realized prices in 2010 and 2011, our realized price, including financial derivatives settlements, would have decreased by $0.70/Mcf and $0.10/Mcf for the years ended December 31, 2010 and 2011.

(4) 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 capital expenditures in our acquisition, development and exploration activities for each of the three years ended December 31:

	2011	2010 (In millions)	2009
United States			
Acquisition Costs:			
Proved	$	$ 51	$ 87
Unproved	45	269	89
Development Costs	694	276	324
Exploration Costs:			
Delay rentals	8	9	5
Seismic acquisition and reprocessing	32	15	27
Drilling	818	576	323
Asset Retirement Obligations	25	7	36
Total full cost pool expenditures	1,622	1,203	891
Non-full cost pool expenditures	18	35	34
Total capital expenditures	$ 1,640	$ 1,238	$ 925
Brazil and Egypt[1]			
Acquisition Costs:			
Unproved	$	$	$ 51
Development Costs	12	28	118
Exploration Costs:			
Seismic acquisition and reprocessing	9	6	3
Drilling	6	52	64
Asset Retirement Obligations			6
Total full cost pool expenditures	27	86	242
Non-full cost pool expenditures	2	1	4
Total capital expenditures	$ 29	$ 87	$ 246
Worldwide[1]			
Acquisition Costs:			
Proved	$	$ 51	$ 87
Unproved	45	269	140
Development Costs	706	304	442
Exploration Costs:			
Delay rentals	8	9	5
Seismic acquisition and reprocessing	41	21	30
Drilling	824	628	387
Asset Retirement Obligations	25	7	42
Total full cost pool expenditures	1,649	1,289	1,133
Non-full cost pool expenditures	20	36	38
Total capital expenditures	$ 1,669	$ 1,325	$ 1,171

(1) Total capital expenditures for Egypt were $8 million, $20 million and $81 million for the years ended December 31, 2011, 2010 and 2009.

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Markets and Competition

We primarily sell our domestic oil and natural gas 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. Our domestic agreements to deliver oil or natural gas represent less than 20 MMcf/d of our oil and natural gas production. In Brazil, we sell the majority of our oil and natural gas under long-term contracts to Petrobras. 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. The gas sales agreement also includes a minimum daily delivery commitment of our natural gas production. The current delivery commitment is approximately 15 MMcf/d and can be modified on an annual basis depending on the production capacity of the subject wells. We do not anticipate being unable to meet the delivery commitment. We enter into derivative contracts on our oil and natural gas 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 oil and natural gas reserves and in the sale of oil, natural gas and NGL. Our competitors include major and intermediate sized oil and natural gas companies, independent oil and natural gas 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, completion 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 oil and natural gas 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 various governmental safety and environmental regulations in the jurisdictions in which we operate.

Our domestic operations under federal oil and natural gas 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 Office of Natural Resources Revenue within the Department of Interior, 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.

Hydraulic Fracturing. Hydraulic fracturing is the well stimulation technique we use to maximize productivity of our oil and natural gas wells in many of our domestic basins, including in our Haynesville, Eagle Ford, Wolfcamp, Altamont, Wilcox, Raton and Black Warrior programs. Hydraulic fracturing is also used, to a lesser extent, in parts of our Gulf of Mexico and Texas Gulf Coast programs. We currently do not use hydraulic fracturing in our Arkoma and Indiana programs. Our net acreage position in basins in which hydraulic fracturing is utilized total approximately 2 million acres. Approximately 98 percent of our domestic proved undeveloped oil and natural gas reserves are subject to hydraulic fracturing. During 2011, we incurred costs of approximately $400 million associated with hydraulic fracturing.

Hydraulic fracturing fluid is typically composed of over 99 percent water and proppant, which is usually sand. The other 1 percent or less of the fluid is composed of additives that may contain acid, friction reducer, surfactant, gelling agent and scale inhibitor. We retain service companies to conduct such operations and we have worked with several service companies to evaluate, test and, where appropriate, modify our fluid design to reduce the use of chemicals in our fracturing fluid. We have worked closely with our service companies to provide voluntarily disclosure of our hydraulic fracturing fluids through the Groundwater Protection Council s FracFocus web site.

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In order to protect surface and groundwater quality during the drilling and completion phases of our operations, we follow applicable industry practices and legal requirements of the applicable state oil and natural gas commissions with regard to well design, including requirements associated with casing steel strength, cement strength and slurry design. Our activities in the field are monitored by state and federal regulators. Key aspects of our field protection measures include: (i) pressure testing well construction and integrity, (ii) casing and cementing practices to ensure pressure management and separation of hydrocarbons from groundwater, and (iii) public disclosure of the contents of hydraulic fracture fluids.

In addition to these measures, our drilling, casing and cementing procedures are designed to prevent fluid migration, which typically include some or all of the following:

Our drilling process executes several repeated cycles conducted in sequence drill, set casing, cement casing and then test casing and cement for integrity before proceeding to the next drilling interval.

Conductor casing is drilled and cemented or driven in place. This string serves as the structural foundation for the well. Conductor casing is not necessary or required for all wells.

Surface casing is set within the conductor casing and is cemented in place. Surface casing is set for all wells. The purpose of the surface casing is to contain wellbore fluids and pressure and protect Underground Sources of Drinking Water (USDW) as identified by federal and state regulatory bodies. The surface casing and cement isolates wellbore materials from any potential contact with USDW s.

Intermediate casing is set through the surface casing to a depth necessary to isolate abnormally pressured subsurface formations from normally pressured formations. Intermediate casing is not necessary or required for all wells. Our standard practices include (a) cementing above any hydrocarbon bearing zone and (b) performing casing pressure and other tests to verify the integrity of the casing and cement.

Production casing is set through the surface and intermediate through the depth of the targeted producing formation. Our standard practices include (a) pumping cement above the confining structure of the target zone and (b) performing casing pressure tests and other tests to verify the integrity of the casing and cement. If any problems are detected, then appropriate remedial action is taken to ensure wellbore integrity.

With the casing set and cemented, a barrier of steel and cement is in place that is designed to isolate the wellbore from surrounding geologic formations. This barrier as designed mitigates against the risk of drilling or fracturing fluids entering potential sources of drinking water.

In addition to the required use of casing and cement in the well construction, we follow additional regulatory requirements and industry operating practices. These typically include (a) pressure testing of casing and surface equipment, (b) continuous monitoring of surface pressure, pumping rates, volumes of fluids and chemical concentrations, and (c) continuous monitoring of well pressure during hydraulic fracturing operations. When any pressure differential outside the normal range of operations occurs, the pumps are promptly shut off until the cause of the pressure differential is identified and any required remedial measures are completed. Hydraulic fracturing fluid is delivered to our sites in accordance with Department of Transportation (DOT) regulations in DOT approved shipping containers using DOT transporters.

We also have procedures to address water use and disposal. This includes evaluating surface and groundwater sources, commercial sources, and potential recycling and reuse of treated water sources. When commercially and technically feasible, we use recycled or treated water. This practice helps mitigate against potential adverse impacts to other water supply sources. When using raw surface or groundwater, we obtain all required water rights or compensate owners for water consumption. We are evaluating additional treatment capability to augment future water supplies at several of our sites. During our drilling operations, we manage waste water to minimize risks and costs. Frac water or flowback water returned to the surface is typically contained in steel tanks or pits. Water that is not treated for reuse is usually piped or trucked to waste disposal injection wells, many of which we own and operate. These wells are permitted through Underground Injection Control (UIC) program of the

Safe Drinking Water Act. We also use commercial injection facilities for frac fluid disposal, which typically dispose of the frac fluids in permitted injection disposal wells. In Alabama, we operate a water treatment disposal facility with a permitted surface discharge. This facility is regulated under the National Pollutant Discharge Elimination System (NPDES) program.

We have not received regulatory citations or notice of suits related to our hydraulic fracturing operations for environmental concerns. We have experienced no material incidents of surface spills of fluids associated with hydraulic fracturing. Consistent with local, state and federal requirements, any releases were reported to appropriate regulatory agencies and site restoration was completed. No remediation reserve has been identified or anticipated as a result of these incidents.

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Spill Prevention/Response Procedures. There are various state and federal regulations that are designed to prevent and respond to any spills or leaks resulting from exploration and production activities. In this regard, we maintain spill prevention control and countermeasures programs, which frequently include the installation and maintenance of spill containment devices designed to contain spill materials on location. With regard to offshore operations, we are limited to exploration and production activities in shallow waters. As a result, we do not have any well control equipment on the seafloor and they are typically located on the deck of the platform. In addition, we maintain emergency response plans to minimize potential environmental impacts in the event of a spill or leak or any material hydraulic fracturing well control issue. We have developed a specialized oil spill response plan for offshore operations and a separate emergency response plan for onshore operations.

Our offshore plan is reviewed and approved by Bureau of Safety and Environmental Enforcement (BSEE). We conduct annual training and drills for various upset scenarios. To augment our internal capability, we retain the services of vendors to assist our spill management team to the extent that we experience any prolonged and significant incidents. We also maintain contractual agreements and memberships with additional oil spill and emergency service providers and co-ops for equipment, response personnel, dispersant and aircraft, vessels, wildlife rehabilitation, and shoreline protection and cleanup.

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Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s oil and natural gas production and to manage El Paso s overall price risk, including managing certain legacy contracts. This segment also has agreements with our midstream joint venture to market the natural gas and natural gas liquids production from its Utah operations. All of our contracts are subject to counterparty credit and non-performance risks while our mark-to-market contracts are also subject to interest rate exposure. As of December 31, 2011, we managed the following types of contracts:

Natural gas transportation contracts. Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable commodity charges. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the production levels of our Exploration and Production segment, 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, 2011:

	Affiliated Pipelines[(1)]	Other Pipelines
Daily capacity (MMBtu/d)	495,000	63,000
Expiration	2012 to 2028	2012 to 2026
Receipt points / Delivery points	Various	Various

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

Legacy natural gas and power contracts. As of December 31, 2011, we had several physical natural gas contracts with power plants associated with our legacy trading activities. These contracts obligate us to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028 with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d. These natural gas supply contracts had associated transportation volumes and costs which are included in our transportation contracts above. In addition, we had power contracts that require us to swap locational differences in power prices between three power plants in Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub on approximately 1,700 GWh to 3,700 GWh, to provide annually approximately 1,700 GWh of power and approximately 71 GW of installed capacity in the PJM pool through 2016. We have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

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 (CFTC). In 2010, federal legislation was enacted to impose additional regulations on derivative transactions. The CFTC is in the process of adopting and implementing regulations, including the creation of position limits and certain exemptions for swap transactions.

Other Activities

We currently have a number of other activities that include our corporate general and administrative functions, midstream operations and miscellaneous businesses. As of December 31, 2011, our midstream operations consist primarily of wholly-owned assets in the Eagle Ford area in south Texas, and an equity investment in a joint venture that owns the Altamont natural gas gathering system, processing plant and fractionation facilities in the Uintah basin of Utah. The joint venture entered into a $150 million revolver in 2011 and is expanding the Altamont system. Additionally, we and our joint venture partner have each committed to make up to $500 million of future capital contributions to the joint venture for additional midstream projects to be acquired or developed by the joint venture. In February 2012, we executed an agreement with our midstream joint venture to transfer our wholly owned investment in the Eagle Ford gathering systems to the joint venture for approximately $85 million in cash. During 2011, midstream capital expenditures totaled approximately $80 million. Our midstream business is also evaluating several larger scale projects in various emerging shale plays including the Utica and Marcellus Shales in the northeast United States.

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Environmental

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

Employees

As of February 20, 2012, we had 4,858 full-time employees, of which 86 employees are subject to collective bargaining arrangements.

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 Securities and Exchange Commission (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 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 such variances can be material. Where we 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. The words believe, expect, estimate, anticipate and similar expressions will generally identify forward-looking statements. All of ou forward-looking statements, whether written or oral, are expressly qualified by these and other cautionary statements. We disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date provided. 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 of our forward-looking statements. If any of the following risks were actually to occur, our business, results of operations, financial condition and growth could be materially adversely affected. In that case, the value of our debt and equity securities could decline materially.

Common Risks Related to All of Our Businesses

The supply and demand for oil, natural gas and NGLs could be adversely affected by many factors outside of our control which could negatively affect us.

Our success depends on the supply and demand for oil, natural gas and NGLs. The degree to which each of our businesses is impacted by changes in supply or demand varies. For example, our pipeline business is not as significantly impacted as our other businesses in the short-term by reductions in the supply or demand for natural gas since our pipelines recover most of their revenues from reservation charges under longer-term contracts that are not dependent on the supply and demand of natural gas in the short-term. However, all of our businesses can be negatively impacted by sustained downturns in supply and demand for oil, natural gas or NGLs. One of the major factors that will impact natural gas demand will be the potential growth of natural gas in the power generation market, particularly driven by the speed and level of which coal-fired power generation is replaced with natural gas-fired power generation. One of the major factors that has been impacting natural gas supplies has been the significant growth in unconventional sources, such as from shale plays. In addition, the supply and demand for oil, natural gas and NGLs for our businesses will depend on many other factors outside of our control, which include, among others:

- Adverse changes in global economic conditions, including changes that negatively impact general demand for oil and its refined products; power generation and industrial loads for natural gas; and petrochemical, refining and heating demand for NGLs;

- Adverse changes in geopolitical factors, including the establishment of production levels by the Organization of Petroleum Exporting Countries (OPEC), political unrest and changes in foreign governments in producing regions of the world and unexpected wars, terrorist activities and others acts of aggression;

- Adverse changes in domestic regulations that could impact the supply or demand for natural gas, including potential restrictive regulations associated with hydraulic fracturing operations;

- Technological advancements that may drive further increases in production and reductions in costs of developing oil and natural gas shales;

- The need of many producers to drill to maintain either revenues or leasehold positions regardless of current prices;

The oversupply of NGLs that may be caused by the wider spread between oil and natural gas prices;

Competition from imported LNG and Canadian supplies, alternate fuels and renewable energy sources;

Increased prices of oil, natural gas or NGLs that could negatively impact demand;

Increased costs to explore for, develop, produce, gather, process and transport oil, natural gas or NGLs, including increases in oil field service costs;

Adoption of various energy efficiency and conservation measures; and

Perceptions of customers on the availability and price volatility of our products, particularly customers perceptions on the volatility of natural gas prices over the longer-term.

The prices for oil, natural gas and NGLs could be adversely affected by many factors outside of our control which could negatively affect us.

Our success depends upon the prices we receive for our oil, natural gas and NGLs. Oil, natural gas and NGL prices historically have been volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. There is a risk that commodity prices, which are at relatively low levels at this time, could remain depressed for sustained periods. The degree to which each of our businesses is impacted by lower commodity prices varies. For example, our pipeline business is not as significantly impacted in the short-term by changes in natural gas prices as our other businesses. Subject to our risk mitigation and hedging strategies for our other businesses, our exploration and production and midstream businesses are more likely to be impacted by short-term changes in commodity prices. However, all of our businesses can be negatively impacted in the long-term by sustained depression in commodity prices for oil, natural gas or NGLs, including reductions in (a) differentials between receipt and delivery points on our system and our ability to renew pipeline transportation contracts on favorable terms, as well as to construct new pipeline and processing infrastructure and (b) our drilling opportunities in our exploration and production business. The prices for oil, natural gas and NGLs are subject to a variety of additional factors that are outside of our control, which include, among others:

- Changes in regional, domestic and international supply and demand;
- Volatile trading patterns in commodity-futures markets;
- Changes in basis differentials among different supply basins that can negatively impact our ability to compete with supplies from other basins, including our ability to maintain pipeline transportation revenues and renew transportation contracts in supply basins that are not as competitive as other alternatives;
- Changes in the costs of exploring for, developing, producing, transporting, processing and marketing each of these products;
- Increased federal and state taxes, if any, on the sale or transportation of oil, natural gas and NGL;
- The price and availability of supplies of alternative energy sources; and
- The amount of capacity available to gather, process and transport our products out of our production areas to more liquid points of delivery and sale.

If oil and natural gas prices decrease, it may negatively impact our estimated proven oil and natural gas reserves and may require us to take write-downs of the carrying values of our oil and natural gas properties.

Prolonged or substantial declines in commodity prices can negatively impact our estimated proven oil and natural gas reserves which can cause us to incur non-cash charges to earnings. Such price declines could also result in increasing our rates of depreciation, depletion and amortization, which could further decrease earnings. The majority of our proved reserves at December 31, 2011 are natural gas and, as a result we are substantially more sensitive to changes in natural gas prices than to changes in oil and NGL prices. In addition, such decreases in commodity prices could negatively impact the amount of oil and natural gas production that we can produce economically in the future. On the other hand, increases in these commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in such commodity prices.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible ceiling test charges. Based on specific market factors and circumstances at the time of prospective ceiling test reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. For example, as a result of the release of costs into the Brazilian full cost pool substantially due to the recent denial of a necessary environmental permit as well as the completion of our evaluation of certain Brazilian exploratory wells drilled in 2009 and 2010, we recorded non-cash international ceiling test charges of approximately $152 million in 2011. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. Additionally, we may incur ceiling test charges in Egypt depending on the results of our activities in that country. Finally, in light of the recent decline in natural gas prices in the United States, it is possible we could experience ceiling test charges for our domestic natural gas properties in the future. These ceiling test charges could have a material adverse effect on our results of operations for the periods in which such charges are taken.

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

We use futures, over-the-counter options and swaps to mitigate commodity price, basis and interest rate exposures. However, we do not typically hedge all of these exposures. For example, we do not typically hedge positions beyond several years with regard to commodity or basis risks. As a result, we are subject to commodity price and basis exposure, particularly in our exploration and production business that has a multi-year drilling program for our proved reserves and unproved resources.

Currently, all of the hedges we enter into to mitigate commodity price risk are not designated as accounting hedges and are therefore marked to market. As a result, we still experience volatility in our revenues and net income as a result of changes in commodity prices, counterparty non-performance risks, correlation factors and changes in the liquidity of the market. Furthermore, the valuation of these financial instruments involves estimates that are based on assumptions that could prove to be incorrect and result in financial losses. Although we have internal controls in place that impose restrictions on the use of derivative instruments, there is a risk that such controls will not be complied with or will not be effective and we could incur substantial losses on our derivative transactions. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital and liquidity when commodity prices or interest rates change.

To the extent we enter into derivative contracts to manage our commodity price exposure, basis and interest rate exposures, we may forego the benefits we could otherwise experience if such prices, differentials or rates were to change favorably. In addition, when we enter into fixed price derivative contracts, we could experience losses and be required to pay cash to the extent that commodity prices, basis positions or interest rates were to increase above the fixed price.

Our businesses are subject to competition from third parties which could negatively affect us.

The oil, natural gas and NGL businesses are highly competitive. In our pipeline business, we compete with other interstate and intrastate pipeline companies as well as gatherers and storage companies for the transportation and storage of natural gas. We also compete with suppliers of alternative energy sources used to generate electricity, such as coal and fuel oil. We frequently have one or more competitors in the supply basins and markets that we are connected to. This includes new pipeline systems that have recently been constructed from supply basins in which one or more of our pipelines are located (including the Bison and Rockies Express pipeline systems) and growing competition in many of the markets that we serve, including many of the markets in the northeast and southwest (including Transwestern s pipeline into Phoenix). In addition, our EPNG system experienced a loss of demand when an LNG terminal was completed south of the Mexico California border.

In our exploration and production business, we compete with third parties in the search for and acquisition of leases, properties and reserves, as well as the equipment, materials and services required to explore for and produce our reserves. There has been intense competition for the acquisition of leasehold positions, particularly in many of the oil and natural gas shale plays. Our competitors include the major and independent oil and natural gas companies, foreign banks and oil companies and individual producers, many of which have financial and other resources that are substantially greater than those available to us. Similarly, we compete with many third parties in the sale of oil, natural gas and NGLs to customers, some of which have substantially larger market positions, marketing staff and financial resources than us.

In our midstream business, we compete with third parties to gather, transport, process, fractionate, store or handle hydrocarbons. Although we have attempted to leverage the synergies between our pipeline and exploration and production businesses, most of these third parties have existing facilities and as a result have more scale and personnel than us. Therefore, there can be no assurances regarding the success of our midstream business, including our ability to compete for individual projects.

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Our operations are subject to operational hazards and uninsured risks which could negatively affect us.

Our operations are subject to a number of inherent operational hazards and uninsured risks such as:

- *Adverse weather conditions, natural disasters, and/or other climate related matters* including extreme cold or heat, lightning and flooding, fires, earthquakes, hurricanes, tornadoes and other natural disasters. 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 (GHG) could also have a negative impact upon our operations in the future, particularly with regard to any of our facilities that are located in or near the Gulf of Mexico and other coastal regions.

- *Acts of aggression on critical energy infrastructure* including terrorist activity or cyber security events. We are subject to the ongoing risk that one of these incidents may occur which could significantly impact our business operations and/or financial results. Should one of these events occur in the future, it could impact our ability to operate or control our pipeline assets and/or operate our drilling and exploration processes, our operations could be disrupted, property could be damaged and/or customer information could be stolen resulting in substantial loss of revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation and litigation and/or inaccurate information reported from our pipeline and exploration and production operations to our financial applications, to our customers and to regulatory entities.

- *Other hazards* including the collision of third-party equipment with our infrastructure (such as damage caused to our underground pipelines by third party excavation or construction or damage from collisions with vessels in our exploration and production operations); explosions, pipeline failures, mechanical and process safety failures, well blowouts, formations with abnormal pressures and collapses of wellbore casing or other tubulars; events causing our facilities to operate below expected levels of capacity or efficiency; uncontrollable flows of natural gas, oil, brine or well fluids, release of pollution or contaminants into the environment (including discharges of toxic gases or substances) and other environmental hazards.

Each of these risks could result in (a) damage or destruction of our facilities, (b) damages and injuries to persons and property or (c) business interruptions while damaged energy and/or technology infrastructure is repaired or replaced, each of which could cause us to suffer substantial losses. While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels, limits on our maximum recovery and do not cover all risks. For example, from time to time we may not carry, or may be unable to obtain on terms that we find acceptable, insurance coverage for certain exposures including, but not limited to, certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm / hurricane exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance will not compensate us fully for our losses. As a result, we could be adversely affected if a significant event occurs that is not fully covered by insurance.

Certain of our business operations are subject to joint ventures or are operated by third parties, which could negatively impact our control and operation of these operations.

Some of our pipeline and exploration and production business operations and interests are either subject to joint ventures or are operated by other companies. The most significant of these are our equity interests in Citrus Corporation (and its Florida Gas operations), GLNG, and Ruby in our pipeline segment, our equity interest in Four Star in our exploration and production segment and our equity interest in our midstream business. Although we operate the substantial majority of the properties in our exploration and production business, certain of the properties are operated by third party working interest owners. In certain cases, (a) we have limited ability to influence or control the day to day operation of such joint ventures or properties, including compliance with environmental, safety and other regulations, (b) we cannot control the amount of capital expenditures that we are required to fund with respect to these properties, (c) we are dependent on third parties to fund their required share of capital expenditures, (d) we are dependent on third parties for financial reporting matters upon which our financial statements are based and (e) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. In addition, we depend on third parties to gather, store and transport natural gas upstream or downstream of the assets or facilities of our businesses. If these third party facilities were to become unavailable or reduced for any reason, then revenues generated from our assets and facilities that utilize them could be negatively impacted.

We are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.

Our operations are subject to a complex set of federal, state and local laws and regulations that tend to change from time to time and generally are becoming increasingly more stringent. In addition to laws and regulations affecting our individual business units, there are various laws and regulations that regulate various market practices in the industry, including antitrust laws and laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission (FTC), FERC and CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years. In addition, all of our businesses are subject to laws and regulations that govern environmental, health and safety matters. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, as well as regulations designed for the protection of human health and safety and threatened or endangered species. Compliance obligations can result in significant costs to install and maintain pollution controls, and to maintain measures to address personal and process safety and protection of the environment and animal habitat near our operations. We are often obligated to obtain permits or approvals in our operations from various federal, state and local authorities, which permits and approvals (including renewals thereof) can be denied or delayed. In addition, we are exposed to fines and penalties to the extent that we fail to comply with the applicable laws and regulations, as well as the potential for limitations to be imposed on our operations. These regulations often impose remediation obligations associated with the investigation or clean-up of contaminated properties, as well as damage claims arising out of the contamination of properties or impact on natural resources. Finally, many of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we operate assets that are located on federal lands located both onshore and offshore, which are regulated by the Department of the Interior, particularly by the Bureau of Land Management (BLM) and the Bureau of Ocean Energy Management, Regulation and Enforcement. We also have pipeline and exploration and production operations on Native American tribal lands, which are regulated by the Department of the Interior, particularly by the Bureau of Indian Affairs, as well as local tribal authorities. Operations on these properties are often subject to additional regulations and compliance obligations, which can delay our access to such lands and impose additional compliance costs.

The laws and regulations (and the interpretations thereof) that are applicable to our businesses could materially change in the future and increase the cost of our operations or otherwise negatively impact us.

The regulatory framework affecting our businesses is frequently subject to change, with the risk that either new laws and regulations may be enacted or existing laws and regulations may be amended. Such new or amended laws and regulations can materially affect our operations and our financial results. In this regard, there have been proposals to adopt or amend federal, state, local and tribal laws and regulations that could negatively impact our businesses, which includes among others:

- *Climate Change and other Emissions.* The Environmental Protection Agency (EPA) and several state environmental agencies have adopted regulations to regulate GHG emissions. It is uncertain at this time what impact the existing and proposed regulations will have on the demand for natural gas and on our operations. This will largely depend on what regulations are ultimately adopted; how the requirements of these regulations are implemented; and incentives and subsidies provided to other fossil fuels, nuclear power and renewable energy sources. Although the EPA has adopted a tailoring rule to regulate GHG emissions, it is not expected to materially impact our existing operations until 2016. However, the tailoring rule is subject to judicial reviews and such reviews could result in the EPA being required to regulate GHG emissions at lower levels that could subject many of our larger facilities to regulation prior to 2016. There have also been various legislative and regulatory proposals and final rules at the federal and state levels to address air emissions from power plants and industrial boilers. Although such rules and proposals will generally favor the use of natural gas over other fossil fuels such as coal, it remains uncertain what regulations will ultimately be adopted and when they will be adopted. Finally, there have been other various environmental regulatory proposals that could increase the cost of our environmental liabilities as well as increase our future compliance costs. For example, the EPA has implemented more stringent emission standards with regard to certain oil and natural gas operations that will affect our businesses. It is uncertain what impact new environmental regulations might have on us until further definition is provided by the various legislative, regulatory and judicial branches. In addition, any regulations would likely increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase air emission credits; and utilize electric-driven compression at facilities to obtain regulatory permits and approvals in a timely manner. 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 oil, natural gas and NGLs, 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.

Renewable / Conservation Legislation. There have been various legislative and regulatory proposals at the federal and state levels and legislation enacted in certain states to provide incentives and subsidies to (a) shift more power generation to renewable energy sources and (b) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGL consumption and thus have negative impacts on our operations and financial results.

E&P Safety. Various regulations have been proposed and implemented that could materially impact the costs of exploration and production operations (particularly in the offshore region and on federal lands), as well as cause substantial delays in the receipt of regulatory approvals from both an environmental and safety perspective. Although our presence offshore has been greatly reduced (including having no operations in the deepwater), such proposed and implemented regulations could impact our remaining exploration and production operations in the Gulf of Mexico. It is also possible that similar, more stringent, regulations might be enacted or delays in receiving permits may occur in other areas, such as in offshore regions of other countries (such as Brazil) and in other onshore regions of the United States (including drilling operations on other federal or state lands). There have also been more stringent proposals in various regions of the U.S. with regard to water usage and disposal in our businesses that could also negatively affect our operations.

Pipeline Safety. New federal legislation was enacted in December 2011 associated with pipeline safety and integrity issues, including changes that require installation of additional valves and other equipment on our pipelines and potential expansion of high consequence areas. The legislation requires the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration to conduct various studies, which may ultimately result in additional regulations that could negatively affect our operations.

Hydraulic Fracturing. Hydraulic fracturing is a process commonly used to stimulate the recovery of production from shale formations, tight sands, coal bed methane and other unconventional reservoirs. Hydraulic fracturing has primarily been regulated at the state level through permitting and compliance requirements. Various federal and state laws and regulations have been proposed to impose more stringent regulation of the hydraulic fracturing process, as well as to require additional disclosures regarding the chemicals used in the process. Such laws and regulations if adopted could impose additional costs in our operations, as well as cause significant delays in obtaining regulatory approvals to drill and complete wells. In addition, there have been proposals to restrict certain buyers from purchasing oil and natural gas produced from wells that have utilized hydraulic fracturing in their completion process, which could negatively impact our ability to sell our production from wells that utilized these fracturing processes. For a further description of hydraulic fracturing as it relates to our exploration and production activities, see Item 1. Business.

Derivatives. Federal legislation was enacted in 2010 to impose additional regulation on derivative transactions. The CFTC is in the process of adopting implementing regulations, including the creation of position limits and certain exemptions from the general requirement that swap transactions be cleared through a central exchange for which collateral must be posted. Although we do not currently expect that such regulations will have a material adverse impact on us, the regulations have not been finalized and there is a risk that the regulations ultimately adopted might negatively impact our marketing activities as well as our hedging activities. For example, the proposed regulations currently would not require collateral to be posted for our hedging transactions by either us or our counterparties, which are often financial institutions. However, if we were required to post collateral for our hedging transactions in the future either pursuant to the final regulations that are adopted or by our counterparties, then it would (a) negatively impact our liquidity and reduce cash available for capital expenditures and/or (b) reduce our ability to enter into hedges to reduce our commodity price exposure thereby making our results of operation more volatile and our cash flows less predictable. In addition, the new regulations could also significantly reduce the availability of counterparties and derivatives, increase the costs of derivatives that are available and negatively alter the terms of the derivative contracts.

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Tax Policies. Various federal legislation has been proposed to materially revise the tax provisions associated with the energy industry. For example, proposed changes include (a) elimination of current deductions for intangible drilling and development costs, (b) the repeal of the percentage depletion allowance for oil and gas properties, (c) implementation of certain international tax reforms, (d) repeal of the manufacturing tax deduction for oil and natural gas companies, (e) an increase in the geological and geophysical amortization period for independent producers and (f) taxation of carried interests, including potential taxation of earnings at EPB. Although we are less impacted by such proposals than many of our peers due to our net operating loss position, any such proposals if implemented could have a negative impact on our financial results and results for operations, as well as deplete our net operating loss position sooner than expected. There have also been proposals to simplify the tax code by generally eliminating deductions and reducing the effective corporate and individual tax rates, which could negatively impact the tax allowance in our FERC-approved pipeline rates and impact the return and yield expectations of our investors and the investors of EPB. It is unclear whether these or other changes will be enacted and if enacted when they will become effective. Any such changes could negatively affect us.

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

We are subject to the risk that our counterparties fail to make payments to us within the time required under our contracts. Our current largest exposures are associated with shippers under long-term transportation contracts on our pipeline systems and with some of our hedging transactions. Our credit procedures and policies may not be adequate to fully eliminate counterparty credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future counterparties fail to pay and/or perform, we could be adversely affected. For example, with respect to our pipeline and midstream businesses, we may not be able to effectively remarket capacity or enter into new contracts at similar terms during and after insolvency proceedings involving a customer.

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

As an owner of large energy infrastructure facilities with significant capital expenditures in each of our businesses, we rely on contractors for certain construction, drilling and completion operations and we rely on suppliers for key materials, supplies and services, including steel mills, pipe and tubular manufacturers and oil field service providers. 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, including their performance and warranty obligations. This could result in delays or defaults in performing such contractual obligations and increased costs to seek replacement contractors, each which could adversely impact us.

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

Our businesses require the retention and recruitment of a skilled workforce including engineers, technical personnel and other professionals. We compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible, which have significant institutional knowledge that must be transferred to other employees. If we are unable to (a) retain our current employees, (b) successfully complete our knowledge transfer and/or (c) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

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Risks Related to Our Pipeline Business

The success of our pipeline business depends on many factors beyond our control.

The results of our pipeline business are impacted in the long term by the volumes of natural gas we transport or store and the prices we are able to charge for these services. The volumes we transport and store depend on the actions of third parties that are based on factors beyond our control. Such factors include events that negatively impact our customers demand for natural gas and could expose our pipelines to the risk that we will not be able to renew contracts at expiration or that we will be required to discount our rates significantly upon renewal. In addition, some of our pipeline systems and expansion projects are not currently fully subscribed. For example, some of the pipelines we own or have interests in (such as the Ruby pipeline and FGT Phase VIII expansion) are not currently fully subscribed and there is a risk that additional customer commitments may not be obtained, that additional customer commitments will be delayed or that additional commitments will only be obtained at reduced rates. We are also highly dependent on our customers and downstream pipelines to attach new and increased loads on their systems in order to grow our pipeline businesses. Further, state agencies that regulate our pipelines local distribution company customers could impose requirements that could impact demand for our pipelines services.

The volume of natural gas that we transport and store also depends on the availability of natural gas supplies that are accessible to our pipeline systems, including the need for producers to continue to develop additional gas supplies to offset the natural decline from existing wells connected to our systems. This requires the development of additional natural gas reserves, obtaining additional supplies from interconnecting pipelines, and the development of LNG facilities on or near our systems. There have been major shifts in supply basins over the last few years, especially with regard to the development of new natural gas shale plays and declining production from conventional sources of supplies as well as declining deliveries from Canada. A prolonged 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.

Furthermore, our ability to deliver natural gas to our shippers is dependent upon their ability to purchase and deliver gas at various receipt points into our system. On occasion, particularly during extreme weather conditions, the gas delivered by our shippers at the receipt points into our system is less than the gas that they take at delivery points from our system. This can cause operational problems and can negatively impact our ability to meet our shippers demand.

With the recent rapid growth of shale production in the U.S. and the subsequent drop in natural gas prices, the need and incentive to import LNG to U.S. regasification terminals have greatly diminished. Actual U.S. LNG imports are now at their lowest levels in several years. If shale gas production continues to grow as expected, imports of LNG to the U.S. will remain at minimal levels. Although our existing LNG import terminals are fully subscribed under long term fixed revenue contracts, extended periods of reduced levels of physical LNG imports could necessitate changes in how our LNG facilities are operated to accommodate these potential low flow conditions.

The agencies that regulate our pipeline businesses and their customers could affect our profitability.

Our pipeline businesses are extensively regulated by the FERC, the U.S. Department of Transportation, the U.S. Department of the Interior, the U.S. Coast Guard, the U.S. Department of Homeland Security and various state and local regulatory agencies who have the ability to issue regulations or enforcement orders that may adversely affect our profitability. FERC regulates most aspects of our business, including the terms and conditions of services offered, our relationships with affiliates, construction and abandonment of facilities and the rates charged by our pipelines (including establishing authorized rates of return). Our pipelines periodically file to adjust their rates charged to their customers. There is a risk that after a prescribed regulatory process the FERC may establish rates that are not acceptable to us or have a negative impact on us. In addition, the profitability of our pipeline systems is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. Our operating results can be negatively impacted to the extent that such costs increase in an amount greater than what we are permitted to recover in our rates or to the extent that there is a lag before the pipeline can file and obtain rate increases.

Our existing rates may also be challenged by complaint. The FERC commenced several proceedings against pipeline systems and storage facilities to reduce the rates they were charging their customers. There is a risk that the FERC or customers could file similar complaints on one or more of our pipeline systems and that a successful complaint against our pipeline rates could have an adverse impact on us. For example, the FERC recently initiated an investigation concerning the rates of one of our storage companies, Bear Creek.

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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 could result in lower recourse rates that could negatively impact our investment in EPB.

Certain of our pipeline systems transportation services are subject to negotiated rate contracts that may not allow us to recover our costs of providing the services.

Under FERC policy, interstate pipelines and their customers may execute contracts at a negotiated rate which may be above or below the FERC regulated recourse rate for that service. These negotiated rate contracts are generally not subject to adjustment for increased costs which could occur due to inflation, increases in the cost of capital or taxes or other factors relating to the specific facilities being used to perform the services. It is possible that costs to perform services under negotiated rate contracts will exceed the negotiated rates. Any shortfall of revenue, representing the difference between recourse rates and negotiated rates could result in either losses or lower rates of return in providing such services.

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 are terminated or if we are unable to renegotiate contract terms as favorable as the existing contracts, we could suffer a material reduction in our revenues, earnings and cash flows. For example, basis differentials between receipt and delivery points on our pipeline systems could remain low over time and thereby negatively impact our ability to renew contracts at rates that were previously in place. In addition, basis differentials often remain low during periods in which the price for natural gas is low, such as we are currently experiencing. Our ability to extend and replace contracts could be adversely affected by factors we cannot control, as discussed 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.

We may not succeed in an expansion of our pipeline system.

Our ability to engage in expansion projects will be subject to, among other things, management approval and numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Therefore, we cannot assure you that any additional expansion project will be undertaken or, if undertaken, will be successful.

The success of expansion projects may depend on, among others, the following factors:

- other existing pipelines may provide transportation services to the area to which we are expanding;
- other entities, upon obtaining the proper regulatory approvals, may construct new competing pipelines or increase the capacity of existing competing pipelines;
- a competitor s new or upgraded pipeline could offer transportation services that are more desirable to shippers because of costs, location, facilities or other factors;
- shippers may be unwilling to sign long-term firm transportation contracts for service which would make use of a planned expansion;
- we may be unable to obtain the requisite environmental and regulatory permits and approvals; and
- the FERC may not grant us the required certificates for our expansion projects.

We may also require additional capital to fund any expansion project. If we fail to generate sufficient funds in the future, we may have to delay or abandon potential expansion projects which could require us to write off significant development costs. Moreover, if we are unable to obtain long term firm transportation contracts for volumes that would enable us to cover the costs of any such expansion and provide us with an acceptable rate of return, we may not proceed with such expansion. Also, a potential expansion may cost more than planned to complete and such excess cost may not be recoverable. Our inability to recover any such costs or expenditures could materially adversely affect our business, financial condition, cash flows and results of operations.

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

Our systems rely on a limited number of customers for a significant portion of our systems revenues. For the year ended December 31, 2011, although there is not substantial overlap of the customers of our different pipeline systems, the four largest natural gas transportation customers for each of TGP, CIG, EPNG and SNG accounted for approximately 29 percent, 65 percent, 46 percent and 61 percent of their respective operating revenues. The creditworthiness of our customers may be adversely impacted by negative effects in the economy, including low natural gas prices which can reduce liquidity and cash flows for some of our customers that produce natural gas. The loss of any material 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 us.

The costs to maintain, repair and replace our pipeline systems may exceed our expected levels.

Much of our pipeline infrastructure was originally constructed many years ago. The age of these assets may result in them being more costly to maintain and repair. We may also be required to replace certain facilities over time. In addition, our pipeline assets may be subject to the risk of failures or other incidents due to factors outside of our control (including due to third party excavation near our pipelines, unexpected degradation of our pipelines, unexpected changes in soil conditions as well as design, construction or manufacturing defects) that could result in personal injury, including death, or property damages. Much of our pipeline systems are located in populated areas which increases the level of such risks. Such incidents could also result in unscheduled outages or periods of reduced operating flows which could result in a loss of our ability to serve our customers and a loss of revenues. Although we are targeted to complete our pipeline integrity program which includes the development and use of in-line inspection tools in high consequence areas by its required completion date at the end of 2012, we will continue to incur substantial expenditures beyond 2012 relating to the integrity and safety of our pipelines. In addition, as indicated above there is a risk that new regulations or other regulatory actions associated with pipeline safety and integrity issues will be adopted that could require us to incur additional material expenditures in the future. We are also subject to inherent risk associated with operating storage facilities, including potential risk of gas losses and field degradation.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located. We are subject to the risk that we do not have valid rights-of-way, that such rights-of-way may lapse or terminate, our facilities may not be properly located within the boundaries of such rights-of-way or the landowners otherwise interfere with our operations. Any loss of or interference with these rights could have a material adverse effect on us.

There are accounting principles that are unique to regulated interstate pipeline assets that could materially impact our recorded earnings.

Accounting policies for FERC regulated pipelines are in certain instances different from U.S. GAAP for nonregulated entities. For example, our regulated pipelines are permitted to record certain regulatory assets on our balance sheet that would not typically be recorded under GAAP for nonregulated entities. In determining whether to account for regulatory assets on each of our pipelines, we consider various factors including regulatory changes and the impact of competition to determine the probability of recovery of these assets. Currently, all of our pipeline systems have regulatory assets recorded on their balance sheets. If we determine that future recovery is no longer probable for any of our pipeline systems, then we could be required to write-off the regulatory assets in the future. In addition, we capitalize a carrying cost on equity funds related to our construction of long-lived assets. Equity amounts capitalized are included as other non-operating income on our income statement. To the extent that one of our pipeline expansion projects is not fully subscribed when it goes into service, we may experience a reduction in our earnings once the pipeline is placed into service. 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 evaluate our assets for impairment and write-off the associated regulatory assets and our future earnings could be impacted.

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Risks Related to Our Exploration and Production Business

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

We have a reserve base that is depleted as it is produced. Unless we successfully replace the reserves that we produce, our reserves will decline which will eventually result in a decrease in oil and natural gas 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. If we do not continue to make significant capital expenditures (such as if our access to capital resources becomes 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 us. In addition, we have certain areas in which we have incurred material costs to explore for and develop reserves. 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 from our full cost pool amortization base on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. We have incurred unevaluated capitalized costs associated with development and exploration activities in Brazil and Egypt for which we have no proven reserves recorded at this time. If costs are determined to be impaired, such amounts are transferred to the full cost pool if a reserve base exists or are expensed if a reserve base has not yet been created. Impairments transferred to the full cost pool increase the depletion rate for that country and can result in a ceiling test charge.

Our oil and natural gas drilling and producing operations involve many risks and our production forecasts may differ from actual results.

Our success will depend on our drilling results. Our drilling operations are subject to the risk that (a) we may not encounter commercially productive reservoirs or (b) if we encounter commercially producible reservoirs, we either may not fully recover our investments or that our rates of return will be less than expected. We are also subject to the risk that we encounter unexpected drilling conditions. Our past performance should not be considered indicative of future drilling performance. For example, we have acquired acreage positions in two new domestic oil and natural gas shale areas for which we plan to incur substantial capital expenditures over the next several years. It remains uncertain whether we will be successful in exploring for the reserves in these regions or in developing the reserves that are found. Our success in such areas will depend in part on our ability to successfully transfer our experiences from existing areas into these new shale plays. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different than actual results and such differences could be material.

The success of our exploration and production business is dependent on many other factors, many of which are outside of our control.

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

- The existence of commodity prices that permit us to earn an acceptable return on our capital expended and to continue existing production, rather than shutting in our production;

- Our ability to expand our leased land positions in desirable areas, which often is subject to intense competition from other companies;

- Our ability to successfully integrate acquisitions;

- The availability of rigs, equipment, supplies and personnel on commercially reasonable terms, particularly with regard to specialty rigs and services such as horizontal rigs and hydraulic fracturing services that are required for many of our unconventional drilling programs;

Our ability to obtain timely construction of gathering and pipeline infrastructure to attach our production to markets, as well as our ability to obtain transportation free of any interruptions in service by the parties that we have contracted with to gather, process and transport our production;

Our ability to obtain increased refining capacity for our Altamont oil production, for which there is currently limited capacity to refine the higher degree of wax content contained in the production by us and other producers in the area;

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- 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 royalties and taxes, as well as the withdrawal of tax incentives for exploration and development activity;
- Our ability to receive certain government approvals or permits on a timely basis on terms acceptable to us;
- Title problems and landowner disputes restricting access to our drilling operations;
- Our lack of control over jointly owned properties and properties operated by others; and
- Continued access to sufficient capital at reasonable rates to fund drilling programs, especially in periods of prolonged economic decline and/or low commodity prices when we may be unable to access the capital markets.

Certain of our undeveloped leasehold acreage is subject to leases that will expire in several years unless production is established on units containing the acreage.

Although most of our reserves are located on leases that are held by production, we do have obligations in many of our leases that provide for the expiration of the lease unless certain conditions are met, such as drilling has not commenced on the lease or production in paying quantities is not obtained within a defined time period. If commodity prices remain low or we are unable to fund our anticipated capital program there is a risk that some of our existing proved reserves and some of our unproved inventory could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in a reduction in our reserves and our growth opportunities and therefore negatively impact our financial results.

Estimating our reserves involves uncertainty, our actual reserves will likely vary from our estimates and negative revisions to our reserve estimates in the future could result decreased earnings, losses and impairments.

All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information was prepared internally and was audited by an independent petroleum consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in these estimates varying considerably from actual results. Estimating quantities of proved reserves is complex and involves significant interpretations and assumptions with respect to available geological, geophysical, and engineering data, including data from nearby producing areas. It also requires us to estimate future economic factors, such as commodity prices, production costs, plugging and abandonment costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial production data, there are greater uncertainties in estimating proved undeveloped reserves and proved developed non-producing reserves. There is also greater uncertainty of estimating proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Furthermore, 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.

Therefore, our reserve information represents an estimate and is often different from the quantities of oil and natural gas that are ultimately recovered. The SEC rules require the use of a ten percent discount factor for estimating the value of our future net cash flows from reserves and the use of a 12-month average price. This discount factor may not necessarily represent the most appropriate discount factor, given our costs of capital, actual interest rates and risks faced by our exploration and production business, and the average price will not generally represent the market prices for oil and natural gas over time. Any significant change in commodity prices could cause the estimated quantities and net present value of our reserves to differ and these differences could be material. You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. Finally, the timing of the production and the expenses related to the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value.

We account for our exploration and production activities under the full cost method of accounting. Changes in the present value of these reserves could result in a write-down in the carrying value of our oil and natural gas properties, which could be substantial, and would negatively affect our net income and stockholders equity. It could also result in increasing our rates of depreciation, depletion and amortization, which could decrease earnings.

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. Our estimates of proved reserves assumes that we can and will make these expenditures and conduct these operations successfully. However, future events, including commodity price changes and our ability to access capital markets, may cause these assumptions to change.

Our exploration and production activities are subject to a complex set of regulations that could negatively impact our operations.

Our exploration and production activities are subject to additional regulations that are unique to this business. This includes federal and state regulatory approvals associated with drilling and spacing units, drilling locations, allowable production from wells, unitization or pooling of oil and gas properties, spill prevention plans, limitations on venting or flaring of natural gas and competitive bidding rules on federal and state lands. Generally, the regulations have become more stringent over time and impose more limitations on our operations and cause more costs to be incurred to comply with such increased regulation. Many of these approvals are subject to considerable discretion by the regulatory agencies with respect to the timing and scope of approvals and permits issued. Our inability to obtain these regulatory approvals on terms acceptable to us on a timely basis could have a material negative impact on our operations and financial results.

Our exploration and production operations could result in an equipment malfunction or oil spill that could expose us to significant liability.

Despite the existence of our procedures and plans, there is a risk that we could experience well control problems either in our onshore or offshore operations. As a result, we could be exposed to regulatory fines and penalties, as well as landowner lawsuits resulting from any spills or leaks that might occur. While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels, limits on our maximum recovery and do not cover all risks. For example, from time to time we may not carry, or may be unable to obtain on terms that we find acceptable, insurance coverage for certain exposures including, but not limited to, certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm / hurricane exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance will not compensate us fully for our losses. As a result, we could be adversely affected if a significant event occurs that is not fully covered by insurance.

Although we might also have remedies against our contractors or vendors or our joint working interest owners with regard to any losses associated with unintended spills or leaks the ability to recover from such parties will depend on the indemnity provisions in our contracts as well as the facts and circumstances associated with the causes of such spills or leaks. As a result, our ability to recover associated costs from insurance coverages or third parties is uncertain.

Risks Related to Our Midstream Business

Our midstream business may be subject to additional risks associated with fluctuations in 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 products has been volatile over time. In addition, the relative pricing between these 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 products, which in turn may impact the services we provide.

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 midstream business. Various factors impact the demand for NGL products, including general economic conditions, 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 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, oil and natural gas 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 commodities 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.

Other Risks Related to Our Businesses

Our foreign operations and investments involve special risks.

Our activities outside the United States primarily include (a) pipeline investment and exploration and production projects in Brazil, (b) certain accounts receivables in Brazil associated with our former power business in the country, (c) exploration and production projects in Egypt and (d) a power investment in Pakistan. All are subject to the risks inherent in foreign operations and additional risks from assets located in the United States, which include, among others:

- Loss of revenue, property and equipment as a result of hazards such as wars, insurrection, piracy or acts of terrorism;

- Changes in laws, regulations and policies of foreign governments, including changes in the governing parties, nationalization, expropriation, and unilateral renegotiation of contracts by government entities. For example, it is uncertain what effect the political unrest associated with the changes in the governing parties in Egypt will have on our ability to explore for and produce oil and natural gas from our net acreage positions in the country and the value of our investments;

- Difficulties in enforcing rights against government agencies and other contractual arrangements, including being subject to the jurisdiction of local courts in certain instances;

- The effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies, relative inflation risks, and the imposition of foreign exchange restrictions that may negatively impact convertibility and repatriation of our foreign earnings into U.S. dollars;

- Protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations;

- Protracted delays in payments and collections of accounts receivables from state-owned energy companies;

- Transparency and corruption issues, including compliance issues with the U.S. Foreign Corrupt Practices Act, the United Kingdom bribery laws and other anti-corruption compliance issues; and

- Laws and policies of the United States that adversely affect foreign trade and taxation.

As a general rule, we have elected not to carry political risk insurance against these sorts of risks.

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We have certain contingent liabilities that could exceed our estimates.

We have certain contingent liabilities associated with litigation, regulatory, environmental and tax matters. In this regard, although we have greatly reduced our litigation, regulatory and environmental exposures over the last several years, we continue to have contingent liabilities (see Part II. Item 8, Financial Statements and Supplementary Data, Note 12). In addition, the positions taken in our federal and state tax returns require significant judgments, use of estimates and interpretation of complex tax laws. Although we believe that we have established appropriate reserves for our litigation and tax matters, we could be required to accrue additional amounts in the future and these amounts could be material.

We have also sold a significant number of assets and either retained certain liabilities or indemnified certain purchasers against future liabilities related to businesses and assets sold, including liabilities associated with environmental, tax, litigation, benefits 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 retained liabilities, including a reduction in historical knowledge of the assets and businesses that is required to effectively manage these liabilities or defend any associated litigation or regulatory proceedings.

The costs of providing pension and post retirement health care plans is subject to factors outside of our control and such costs could increase and could negatively affect our financial results.

Our earnings and cash flows may be impacted by the amount of income or expense we record for our various benefit plan obligations. Our benefit plans include obligations under our defined benefit pension plan and welfare plans for our current employees and medical and life insurance benefits for certain retired employees. Although we believe we have established appropriate reserves for these plans, we could be required to accrue additional liabilities in the future and these amounts could be material. For example, our pension plan was underfunded at December 31, 2011. While we do not currently expect to make additional cash contributions in 2012, we may be required to make additional pension plan contributions in the future. Additionally, our pension plan is supported by assets held in trust and the funded status could be negatively impacted by other events, including changes in (a) the value of our assets largely driven by changes in equity and bond markets, (b) the discount rates used to measure pension liabilities and (c) the demographics (including actuarial gains and losses). Although a portion of our postretirement welfare plans are also supported by assets held in a trust, we fund most of our welfare plans on a current basis, including our welfare plan for our current employees and the postretirement welfare plan for certain Case Corporation (Case) retirees. Medical costs have been generally increasing and such costs could require us to incur additional liabilities and make additional cash expenditures to fund such programs that could have a negative impact on our financial results. Furthermore, the costs of maintaining such welfare plans could be negatively impacted by changes that might arise out of recent health care legislation, the effects of which have not been fully determined at this point. Any of these events, which are beyond our control, could negatively impact us.

We have significant existing debt which requires us to dedicate a substantial portion of our cash flows to service our debt payment obligations, as well as reduces our flexibility to respond to changed circumstances.

We have significant debt, debt service and debt maturity obligations, many of which are more significant than our competitors. This requires us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions or general corporate purposes. In addition, these debt levels expose us to more liquidity and default risks than many of our peers, especially during times of financial volatility and reduced commodity prices. It similarly reduces our flexibility to compete on future projects.

We have significant capital programs in our businesses that require us to access capital markets frequently and any inability to obtain access to the capital markets in the future at competitive rates could have a negative impact on us.

We have extensive capital programs in each of our businesses, which require us to frequently access the capital markets. Although the markets have become less volatile than they were several years ago, volatility in the financial markets remain. Since we are rated below investment grade at this time, our ability to access the capital markets and the cost of capital could be negatively impacted in the future. This could require us to forego capital opportunities or make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us with investment grade ratings.

Our current and future debt can be negatively impacted by the ratings assigned to our debt facilities, which could have a negative impact upon us.

The ratings assigned to El Paso s senior unsecured indebtedness are below investment grade, currently rated Ba3 with a negative outlook by Moody s Investor Service, BB- with a stable outlook by Standard & Poor s and BB+ with a negative outlook by Fitch Ratings. These ratings have increased our cost of capital and our operating costs in comparison to many of our peers. There is a risk that these credit ratings may be adversely affected in the future as the credit rating agencies review their general credit requirements as well as review our leverage, liquidity, credit profile and potential transactions. Following the announcement of our proposed merger with Kinder Morgan, Moody s and Fitch adjusted their view of El Paso to a negative outlook. During the pendency of the proposed merger, a decrease in Kinder Morgan s perceived creditworthiness could further negatively affect our ratings. Any reduction in our credit rating could also impact our cost of capital, as well as potentially require us to post additional collateral under certain of our derivative contracts. Any reduction in our credit rating could also negatively impact the credit rating of our subsidiaries, including EPB and one or more of our pipeline subsidiaries, which could also increase their cost of capital. It could also impact our ability, as well as the ability of our subsidiaries, to access the capital markets. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our debt instruments, as well as the market value of our common stock and the units of EPB.

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

We maintain $1.0 billion of our liquidity through the borrowing base facilities of our exploration and production subsidiary. A downward revision of our proved 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 addition, currently a portion of our proved reserves serve as collateral for many of the derivative contracts that we enter into to hedge the commodity price for our production. A reduction in our proved reserves could require us to post additional collateral in the future for a portion of those derivative contracts.

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.

Certain of 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. 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 oil and natural gas reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to foreclose on these collateral interests.

We are subject to interest rate risks.

Although a substantial portion of our debt capital structure has fixed interest rates, changes in market conditions, including potential increases in the deficits of foreign, federal and state governments, could have a negative impact on interest rates that could cause our financing costs to increase. Since interest rates are at historically low levels, it is anticipated that they will increase in the future. Rising interest rates could also negatively impact the market value of our investment in EPB, as changes in interest rates may affect the yield requirements of investors in its units.

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We depend on distributions from our subsidiaries and joint ventures to meet our needs.

We hold debt at a holding company level, a company with no significant assets other than our ownership interests in our operating subsidiaries. We are dependent on the earnings and cash flows, dividends, loans or other distributions from our subsidiaries and joint ventures to generate the funds necessary to meet these obligations. Applicable law and contractual restrictions (including restrictions in our subsidiaries credit facilities and in our joint venture or partnership agreements) may negatively impact our ability to obtain such distributions from our subsidiaries, including the rights of the creditors of our subsidiaries that would often be superior to our interests. A substantial portion of our investments in our interstate pipeline assets are held through subsidiaries or joint ventures. In this regard, our partnership interest in EPB generates substantial cash flow to us. Therefore, our cash flow is dependent upon the ability of EPB to make distributions to its partners (including the incentive distribution rights to us as the general partner). A significant decline in EPB s earnings and/or cash distributions would have a corresponding negative impact on us. For information on the risk factors inherent in the business of EPB, see Item 1A. Risk Factors in the EPB Annual Report and subsequent filings thereof.

Our ability to continue to sell interests in our interstate pipelines and LNG facilities to EPB could be negatively impacted by various factors that would restrict its use as a cost effective vehicle for us to raise capital.

An important source of capital to us in the past and potentially in the future is the sale of interests in our interstate pipelines and LNG facilities to our master limited partnership, EPB. As the general partner of EPB, we are entitled to incentive distribution rights (IDRs). We are currently entitled to receive the maximum level of IDRs. Our ability to sell additional interests to EPB on an accretive basis to the limited partner unitholders may be negatively impacted by such IDRs unless we elect to reduce the level of the IDRs as provided for in the partnership agreement. In addition, as the general partner of the partnership, we could also be subject to claims associated with conflicts of interest and breach of fiduciary duties. Although the partnership agreements expressly define and limit our obligations as the general partner, if any conflicts of interest or breach of fiduciary duties are found, then our ability to sell additional interests in our interstate pipeline assets to EPB could be negatively impacted and any liability resulting from such claims could be material. In either event, there is a risk that this source of capital to us may not be available to us or may become more restricted, thereby negatively impacting the deleveraging of our balance sheet and/or our future capital programs. The ability to sell additional interests in our interstate pipelines and LNG facilities to EPB is also subject to the ability of EPB to access the capital markets. If the access to such markets is unavailable or restricted or if the cost of capital increases, then this important source of capital to us could be negatively impacted in the future. Finally, our ability to sell interests in other pipeline subsidiaries may be restricted by covenants under existing debt agreements and under the merger agreement with KMI.

Risks Related to our Proposed Transactions with Kinder Morgan

Kinder Morgan and El Paso may be unable to obtain the regulatory clearances and approvals required to complete the transactions or, in order to do so, Kinder Morgan and El Paso may be required to comply with material restrictions or satisfy material conditions.

The proposed transactions with Kinder Morgan that were announced on October 16, 2011 are subject to review by the Federal Trade Commission under the Hart-Scott-Rodino Act, as well as several other agencies. The closing of the transactions is also subject to the condition that there be no law, injunction, judgment or ruling by a governmental authority in effect enjoining, restraining, preventing or prohibiting the transactions contemplated by the merger agreement. We can provide no assurance that all required regulatory approvals will be obtained. For example, governmental authorities could seek to block or challenge the transactions as they deem necessary or desirable in the public interest at any time, including after completion of the transactions. In addition, in some circumstances, a competitor, customer or other third party could initiate a private action under antitrust laws challenging or seeking to enjoin the transactions, before or after it is completed. Kinder Morgan may not prevail and may incur significant costs in defending or settling any action under the antitrust laws. Further, even if such approvals are obtained, the governmental agencies may seek to impose certain restrictions or obligations on Kinder Morgan s or El Paso s businesses as conditions for such approval, which could include requiring the divestiture of certain assets or businesses including potential divestitures of certain assets or businesses of Kinder Morgan Energy Partners, L.P. (KMP) or EPB that would require the consent of KMP or EPB, as the case may be. These actions could have the effect of delaying or preventing completion of the proposed transactions or imposing additional costs on or limiting the revenues of El Paso and the combined company following the transactions.

If Kinder Morgan s financing for the transactions is not funded, the transactions may not be completed and Kinder Morgan may be in breach of the merger agreement.

Kinder Morgan intends to finance the cash required in connection with the transactions, including for expenses incurred in connection with the transactions, with debt financing. On February 10, 2012, Kinder Morgan entered into an amendment to its affiliate s existing $1.0 billion revolving credit facility to, among other things, permit the transactions contemplated by the merger agreement, and a new credit agreement to provide a $6.8 billion senior secured 364-day bridge term loan facility, a $5.0 billion senior secured three-year term loan facility and joinder agreement to provide an additional $750 million in commitments under the existing revolving credit facility, all effective upon completion of the merger. The obligation of the lenders to provide the debt financing is subject to various conditions, including the repayment of all amounts outstanding under and termination of El Paso s existing credit facility and other customary closing conditions. In the event any of the closing conditions is not satisfied or waived, or to the extent one or more of the lenders is unwilling to, or unable to, fund its commitments under the debt financing, Kinder Morgan may be required to seek alternative financing or fund the cash required in connection with the merger itself. Due to the fact that there is no funding condition in the merger agreement, if Kinder Morgan is unable to obtain funding from its financing sources for the cash required in connection with the transactions, Kinder Morgan could be in breach of the merger agreement assuming all other conditions to closing are satisfied and may be liable to El Paso for damages.

We may have difficulty attracting, motivating and retaining executives and other employees in light of the transactions.

Uncertainty about the effect of the transactions on our employees may have an adverse effect on us and consequently the combined company. This uncertainty may impair our ability to attract, retain and motivate personnel until the transactions are completed. Employee retention may be particularly challenging during the pendency of the transactions, as employees may feel uncertain about their future roles with the combined company. We may have to provide additional compensation to retain employees. If our employees depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined company, the combined company s ability to realize the anticipated benefits of the transactions could be reduced.

Pending the completion of the transactions, our business and operations could be materially adversely affected.

Under the terms of the merger agreement with KMI, we are subject to certain restrictions on the conduct of our business prior to completing the transactions which may adversely affect our ability to execute certain of our business strategies, including our ability in certain cases to enter into contracts, incur capital expenditures or grow our business. The merger agreement also restricts our ability to solicit, initiate or encourage alternative acquisition proposals with any third party and may deter a potential acquirer from proposing an alternative transaction or may limit our ability to pursue any such proposal. Such limitations could negatively affect our businesses and operations prior to the completion of the proposed transactions. Furthermore, the process of planning to integrate two businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on us.

In connection with the pending transactions, it is possible that some customers, suppliers and other persons with whom we have a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with us as a result of the transactions, which could negatively affect our revenues, earnings and cash flows, as well as the market price of shares of our common stock, regardless of whether the transactions are completed.

We will incur substantial transaction-related costs in connection with the transactions.

We expect to incur a number of non-recurring transaction and merger-related costs associated with completing the transactions, combining the operations of the two companies and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial and accounting advisors, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of the businesses of the two companies. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time. Thus, any net benefit may not be achieved in the near term, long term or at all.

Failure to complete the transactions could negatively affect the trading price El Paso common stock and the future business and financial results of El Paso.

Completion of the transactions is not assured and is subject to risks, including the risks that approval of the transactions by the respective stockholders of Kinder Morgan and El Paso or by governmental agencies is not obtained or that other closing conditions are not satisfied. If the transactions are not completed, or if there are significant delays in completing the transactions, it could negatively affect the trading price of our common stock and the future business and financial results of El Paso, and we will be subject to several risks, including the following:

- the parties may be liable for damages to one another under the terms and conditions of the merger agreement;

- negative reactions from the financial markets, including declines in the price of our common stock due to the fact that current prices may reflect a market assumption that the transactions will be completed;

- having to pay certain significant costs relating to the merger, including, in the case of El Paso in certain circumstances, a termination fee of $650 million and up to $20 million in expenses related to the transaction, plus certain financing-related expenses of Kinder Morgan; and

- the attention of our management will have been diverted to the transactions rather than to our operations and pursuit of other opportunities that could have been beneficial to us, including the prior strategy to spin-off our exploration and production business.

Purported stockholder class action complaints have been filed against El Paso, Kinder Morgan, the members of El Paso s board of directors, El Paso s and Kinder Morgan s merger subsidiaries and Goldman Sachs, challenging the transactions, and an unfavorable judgment or ruling in these lawsuits could prevent or delay the consummation of the proposed transactions and result in substantial costs.

In connection with the proposed transactions, purported stockholders of El Paso have filed several stockholder class action lawsuits in the District Courts of Harris County, Texas and in the Delaware Courts of Chancery. Those lawsuits name as defendants El Paso, Kinder Morgan, the members of the board of directors of El Paso, and, in certain cases, the affiliates of El Paso and Kinder Morgan and Goldman Sachs. Among other remedies, the plaintiffs seek to enjoin the proposed transaction. If a final settlement is not reached, or if a dismissal is not obtained, these lawsuits could prevent or delay completion of the transactions and result in substantial costs to El Paso and Kinder Morgan, including any costs associated with the indemnification of directors. Additional lawsuits may be filed against El Paso and Kinder Morgan, their respective affiliates and El Paso s directors related to the proposed transactions. An additional purported class action lawsuit was filed on behalf of unitholders of EPB in the Delaware Chancery Court in December 2011 against us and El Paso s board of directors. The lawsuit alleges that the merger transaction with KMI adversely affected the unitholders of EPB and that we and El Paso s board of directors breached their fiduciary duties. The defense or settlement of any lawsuit or claim may adversely affect the combined company s business, financial condition or results of operations.

Closing of the proposed transactions may trigger change in control provisions in certain agreements to which we are a party.

Closing of the proposed transactions may trigger change in control provisions in certain agreements to which we are parties. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we are able to negotiate waivers, the counterparties may require a fee for such waiver or seek to renegotiate the agreements on less favorable terms. During the pendency of the proposed transactions, a decrease in Kinder Morgan s perceived creditworthiness may have an adverse effect on our perceived creditworthiness, possibly resulting in a downgrade of credit ratings, tightening of credit under our existing credit facilities, increasing our borrowing costs or, upon completion of the transactions with KMI, could trigger certain change of control provisions to certain agreements to which we are a party. As a result of the announcement of the transactions, we were placed on negative outlook by Moody s and Fitch.

Failure to successfully combine and integrate the organizations and processes of El Paso and Kinder Morgan may adversely affect us.

The success of the proposed transactions will depend, in part, on the ability of Kinder Morgan to realize the anticipated benefits and synergies from combining the businesses of Kinder Morgan and El Paso. To realize these anticipated benefits, the businesses must be successfully combined. If the combined company is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the transactions may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the transactions.

Following consummation of the El Paso and Kinder Morgan merger, our credit rating could be adversely affected, which may increase our borrowing costs.

Kinder Morgan will have considerably higher aggregate levels of indebtedness due to the debt incurred to finance the transaction. There can be no assurance that the credit ratings of Kinder Morgan will not be subject to a downgrade. Our credit ratings may be adversely affected in the event of any downgrade in Kinder Morgan s ratings in light of the ownership interest and operational control of us following the merger. Any reduction in our credit rating could also negatively impact the credit rating of our subsidiaries. Any of such actions by the credit rating agencies could increase our cost of capital and that of our subsidiaries, as well as negatively impact our ability to access the capital markets.

Due to a disagreement between El Paso and one of its joint venture partners, Kinder Morgan s and El Paso s ability to obtain the consents of the independent auditors of the joint venture and of El Paso to include or incorporate by reference their respective audit reports in Kinder Morgan s and El Paso s filings under the Securities Act and the Exchange Act may be severely limited. As a result, Kinder Morgan s and/or El Paso s ability to access capital markets through registered offerings and make certain filings required under the Securities Act and the Exchange Act may be limited, potentially significantly.

El Paso and another party are partners in a pipeline joint venture (referred to as the Joint Venture) in which the other party is currently acting as the operator (referred to as the JV Operator). In connection with a planned amendment to Kinder Morgan s Registration Statement on Form S-4, the JV Operator previously refused to provide a management representation letter to the independent auditor of the Joint Venture. The JV Operator has also indicated that it will continue to refuse to provide such management representation letters to auditors for the Joint Venture except in connection with El Paso s annual and quarterly filings under the Exchange Act. As a result, from time to time, Kinder Morgan and El Paso may be unable to obtain consent from the independent auditor of the Joint Venture to include or incorporate by reference in their respective filings under the Securities Act and the Exchange Act, the audited financial statements of the Joint Venture. Furthermore, Kinder Morgan and El Paso may be unable to obtain the consent of the independent auditor of El Paso (which relies on the audit report of the independent auditor of the Joint Venture in its audit report on the audited financial statements of El Paso) to include or incorporate by reference its audit reports.

The inability to obtain a management representation letter from the JV Operator except in connection with the filing of El Paso s annual report on Form 10-K and quarterly reports on Form 10-Q, and therefore, the inability to obtain the consent of the independent auditor of the Joint Venture and of El Paso to include or incorporate by reference their respective audit reports, may limit the ability of Kinder Morgan to timely make necessary post-effective amendments to its Registration Statement on Form S-4 and the ability of Kinder Morgan and/or El Paso (and their affiliates) to access capital. Notwithstanding the fact the JV Operator has indicated that it will provide a management representation letter to the independent auditor of the Joint Venture in connection with the filing of El Paso s annual report on Form 10-K and quarterly reports on Form 10-Q, there can be no assurance that the JV Operator will, in fact, do so. Failure of the JV Operator to provide a management representation letter in connection with the filing of El Paso s annual report on Form 10-K and quarterly reports on Form 10-Q could inhibit or prevent Kinder Morgan and/or El Paso from accessing the capital markets and/or making filings required under the Securities Act and Exchange Act and could have an adverse impact on the business and operations of Kinder Morgan and/or El Paso, which could be material depending on then-existing circumstances.

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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 material legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 12, and is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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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 20, 2012, we had 24,520 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
2011			
Fourth Quarter	$ 26.62	$ 16.30	$ 0.01
Third Quarter	21.18	16.64	0.01
Second Quarter	21.54	16.72	0.01
First Quarter	18.77	13.42	0.01
2010			
Fourth Quarter	$ 14.08	$ 12.00	$ 0.01
Third Quarter	12.93	10.60	0.01
Second Quarter	13.00	10.17	0.01
First Quarter	11.59	9.55	0.01

Dividends Declared. On February 23, 2012, we declared a quarterly dividend of $0.01 per share of our common stock, payable on April 2, 2012, to shareholders of record as of March 5, 2012. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

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, 2011 to 2008 and for the years ended December 31, 2007 to 2011 is derived from the audited consolidated financial statements for El Paso and its subsidiaries. The selected financial data as of December 31, 2007 is derived from the unaudited consolidated financial statements adjusted to reflect the adoption in 2009 of 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,				
	2011	2010	2009	2008	2007
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,860	$ 4,616	$ 4,631	$ 5,363	$ 4,648
Net income (loss)	$ 427	$ 924	$ (474)	$ (789)	$ 442
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 141	$ 721	$ (576)	$ (860)	$ 1,073
Earnings (loss) per common share from continuing operations attributable to El Paso Corporation s common stockholders:					
Basic	$ 0.19	$ 1.03	$ (0.83)	$ (1.24)	$ 0.57
Diluted	$ 0.18	$ 1.00	$ (0.83)	$ (1.24)	$ 0.57
Cash dividends declared per common share	$ 0.04	$ 0.04	$ 0.16	$ 0.18	$ 0.16
Basic average common shares outstanding	751	698	696	696	696
Diluted average common shares outstanding	774	762	696	696	699
Financial Position Data:					
Total assets	$ 24,314	$ 25,270	$ 22,505	$ 23,668	$ 24,579
Long-term financing obligations, less current maturities	$ 12,605	$ 13,517	$ 13,391	$ 12,818	$ 12,483
Preferred stock of subsidiaries	$	$ 698	$ 145	$	$
Total equity	$ 7,135	$ 6,064	$ 3,991	$ 4,596	$ 5,845

Factors Affecting Trends. During 2011, we recorded non-cash charges in conjunction with the deconsolidation of Ruby Pipeline Holding Company, L.L.C. (Ruby) of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby and $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt. We also recognized a non-cash full cost ceiling test charge in our Brazilian full cost pool of approximately $152 million and debt extinguishment losses of approximately $169 million associated with debt repurchase activity. During 2011 and 2010, EPB issued common units, net of issuance costs, for approximately $0.9 billion and approximately $1.3 billion, respectively. 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 Company (ANR) pipeline system and related assets and also completed the initial public offering of common units in EPB.

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. All forward-looking statements in this section and throughout this Form 10-K should also be read in conjunction with the announcement of our definitive agreement with KMI as further described below and in Part I, Item 1, Business. Our MD&A includes forward-looking statements that are subject to risks and uncertainties (discussed further in Item 1A, Risk Factors) that may result in actual results differing from the statements we make.

Proposed Merger with Kinder Morgan, Inc. On October 16, 2011, we announced a definitive merger agreement with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that valued El Paso at approximately $38 billion (based on the KMI stock price at that date), including the assumption of debt. The merger agreement has been approved by each of our and KMI s board of directors. The completion of the merger is subject to satisfaction or waiver of certain closing conditions including, among others, customary regulatory approvals, approval by our stockholders and approval of the issuance of KMI stock and warrants by KMI s stockholders. A voting agreement has been executed by certain stockholders of KMI, holding approximately 75 percent of the voting power of KMI, in which such stockholders have agreed to vote in favor of the merger and issuance of KMI stock and warrants. The completion of the merger will constitute a change of control for El Paso that may trigger provisions in certain agreements including those related to (i) debt and other financing agreements, (ii) severance agreements and (iii) incentive compensation plan agreements that will result in an immediate acceleration of all unvested stock based compensation awards upon closing of the merger. For our debt and other financing agreements containing covenants related to change in control events and that will not be terminated pursuant to the merger, we have either amended the agreements or obtained waivers of those covenants. However, if there was a downgrade of our credit ratings upon completion of the transactions with KMI, it could trigger certain other change of control provisions to certain agreements to which we are a party.

The merger agreement includes customary representations, warranties and covenants, and specific agreements relating to (i) the conduct of each of El Paso s and KMI s respective businesses between the date of the signing of the merger agreement and the closing of the merger transactions and (ii) the efforts of the parties to cause the merger transactions to be completed. In addition to certain other covenants, we have agreed not to encourage, solicit, initiate or facilitate any takeover proposal from a third party or enter into any agreement, arrangement or understanding requiring us to abandon, terminate or fail to consummate the merger and related transactions. The merger agreement contains certain termination rights for both El Paso and KMI and further provides that, upon termination of the merger agreement, under certain circumstances, El Paso may be required to pay KMI a termination fee equal to $650 million or, in certain other circumstances, El Paso may be required to reimburse KMI for its expenses up to $20 million and certain financing related expenses.

Under the terms of the merger agreement, we have agreed to conduct our business in the ordinary course and in all material respects in substantially the same manner as conducted prior to the date of the merger agreement, subject to certain conditions, restrictions and thresholds including, but not limited to, our ability to (i) commit to capital expenditures above our current capital budgets (ii) acquire, invest in, or dispose of any material properties, assets, or equity interests as defined in the merger agreement (iii) incur new debt, refinance, or guarantee any debt or borrowed money, (iv) enter into, terminate, or amend certain material contracts, (v) issue, grant, sell, or redeem new El Paso capital stock or stock-based compensation awards and/or pay dividends in excess of $0.01/share, among other limitations.

In conjunction with the merger, KMI announced that they intend to sell our exploration and production assets. On February 24, 2012, we entered into a purchase and sale agreement to sell all of our exploration and production assets to an affiliate of Apollo Global Management, LLC (Apollo) and certain other parties for $7.15 billion subject to certain adjustments for items such as contributions or distributions, incurrence of debt and title defects. The sale is contemplated by the merger agreement with KMI. The closing of the sale is conditioned upon the closing of the transactions contemplated by the merger agreement with KMI. Both transactions are expected to be completed in the second quarter of 2012. The purchase and sale agreement contains customary representations and warranties relating to the exploration and production assets and operations. Additionally, El Paso has entered into a performance guarantee in favor of Apollo, under which we guarantee the performance of all of our seller subsidiaries obligations under the purchase and sale agreement. Pursuant to the merger agreement with KMI, KMI is required to indemnify us from any and all cost incurred by us arising from or relating to the sale of the exploration and production assets. Upon completion of the sale, the exploration and production business will be reflected as a discontinued operation in our financial statements.

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Listed below is a general outline of our MD&A:

Our Business includes a summary of our business purpose and description, factors influencing profitability and a summary of our 2011 performance;

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 an overview of our sources and uses of cash, available liquidity, an overview of cash flow activity during 2011, and additional factors that could impact our liquidity;

Off Balance Sheet Arrangements and Contractual Obligations includes a discussion of our (i) off balance sheet arrangements, including guarantees and letters of credit and (ii) other contractual obligations; 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

We 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. We are also a large independent oil and natural gas producer focused on generating competitive financial returns through disciplined capital allocation and portfolio management, cost control and marketing and selling our oil and natural gas production at optimal prices while managing associated price risks. We also have an emerging midstream business. In conjunction with the proposed merger with KMI, KMI announced its intent to sell our exploration and production business. As noted above, the closing of the transaction is subject to customary regulatory, shareholder, and other approvals and is expected to occur in the second quarter of this year. The sale of the exploration and production business is not a condition of closing the merger with KMI. For a further discussion, see *Overview.*

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 oil and natural gas, the costs to explore, develop, and produce oil and natural gas, 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

- Contracting and recontracting pipeline capacity with our customers;
- Maintaining or obtaining approval by the FERC of acceptable rates, terms of service, and expansion projects;
- Ensuring the safety of our pipeline systems and assets;
- Improving operating efficiency; and
- Executing successfully on our expansion projects and developing growth projects in our market and supply areas.

Exploration and Production

Growing our oil and natural gas proved reserve base and production volumes through successful execution of our drilling programs;

Finding and producing oil and natural gas at a reasonable cost; and

Managing price risks to optimize realized prices on our oil and natural gas production.

In addition to these factors, our future profitability will be affected by our ability to execute our strategy, the impacts of volatility in the financial and commodity markets, industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating and capital costs, our debt level and related interest costs, the successful resolution of our historical contingencies and other legacy activities. To the extent possible, we attempt to mitigate certain of these risks through actions, such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements. Additionally, we may also be impacted by hurricanes and other weather events, domestic or international regulatory or other actions in response to events outside of our control (e.g. oil spills).

Summary of 2011 Performance

During 2011, we continued to deliver solid operational performance and a strong base of earnings and cash flows from operations in both our pipeline and exploration and production businesses. In 2011 we completed the remainder of our $8 billion backlog of pipeline expansion projects. Other than our Ruby project, which was placed in service four months later than planned due to permitting and weather delays and was approximately $0.7 billion over the original $3.0 billion budget, these projects were completed on time and on budget. In our exploration and production business, we have continued to execute on our strategy, increasing production volumes, adding proved reserves, lowering per unit cash operating costs, and utilizing our hedging program designed to support our balance sheet and cash flows. We shifted our capital program to provide us more exposure to oil opportunities, particularly in the Altamont, Eagle Ford and Wolfcamp areas. Finally, in our midstream business, our joint venture expanded its asset base in both the Altamont and Eagle Ford operating areas.

During 2011, our Segment EBIT was $1,325 million, compared with $2,341 million for the same period in 2010. Pipelines Segment EBIT in 2011 was significantly impacted by a non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby and a non-cash loss of approximately $125 million recorded upon deconsolidation of Ruby associated with the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt. Our Exploration and Production segment increased production volumes year over year; however, Segment EBIT year-to-date decreased by approximately $233 million largely due to the mark-to-market impacts of our financial derivatives and a third quarter non-cash Brazilian ceiling test charge of approximately $152 million. Our results during these periods were also impacted by $169 million in debt extinguishment losses associated with the repurchase of approximately $1.0 billion of our debt in 2011. Our results are discussed further in the individual segment results that follow.

The following table provides highlights in our core businesses and financing activities:

Area of Operations	Significant Highlights
Pipelines	Completed our $8 billion backlog of expansion projects including the Ruby pipeline project, the Florida Gas Transmission (FGT) Phase VIII Expansion, Phases I and II of the SNG South System III Expansion, Phase II of the SNG Southeast Supply Header, the Gulf LNG Clean Energy and the TGP 300 Line projects
	Received approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our master limited partnership (MLP) which funded the acquisitions primarily through the issuance of common units and debt
	Settled rate cases with the FERC for our CIG and TGP systems
Exploration and Production	Increased our proved oil and natural gas reserves to 4.0 Tcfe in 2011 from 3.4 Tcfe in 2010, which includes a 66 percent increase in our oil and NGL proved reserves from 2010
	Increased consolidated oil and condensate production by 27 percent in 2011. This increase contributed to oil and condensate based revenues being 30 percent of total revenues, a 58 percent increase from 2010.
	Achieved a 100 percent domestic drilling success rate
	Focused our domestic capital program on our core programs in the Haynesville Shale in northwest Louisiana, the Altamont fractured tight oil sands in Utah, the Eagle Ford Shale in south Texas and the Wolfcamp Shale in the Permian Basin in Texas
	Introduced our emerging Louisiana Wilcox program in south Louisiana, which provides additional liquid hydrocarbon resources in our drilling program
	Managed commodity price risk through derivative contracts on a portion of our 2011 - 2014 oil production, and 2011 and 2012 natural gas production
Other	Expanded the Altamont and Eagle Ford operating areas through our midstream operations and joint venture
	Refinanced $3.25 billion in revolving credit extending maturities to 2016

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Results of Operations

Overview

As of December 31, 2011, our business consists of the following segments: Pipelines, Exploration and Production, and Marketing. We also have other business and corporate activities that include midstream and other miscellaneous businesses. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies.

We use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 and 2009 amounts have been conformed to reflect our current performance measure.

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

	2011	2010 (In millions)	2009
Segment			
Pipelines	$ 1,135	$ 1,738	$ 1,481
Exploration and Production	494	727	(1,349)
Marketing	(61)	(50)	20
Other	(243)	(74)	(17)
Segment EBIT	1,325	2,341	135
Interest and debt expense	(948)	(1,031)	(1,008)
Income tax benefit (expense)	50	(386)	399
Net income (loss)	427	924	(474)
Net income attributable to noncontrolling interests	(286)	(166)	(65)
Net income (loss) attributable to El Paso Corporation	$ 141	$ 758	$ (539)

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

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Pipelines Segment

Overview

Our Pipelines segment operates in the United States and consists of interstate natural gas transmission, storage and LNG receiving terminal 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, and LNG terminalling related services consist of two types:

Type	Description	Percent of 2011 Revenues[(1)]
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.	88
Usage and Other	Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges and provide fuel in-kind 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.	12

(1) Excludes revenues associated with liquids and condensate sales. Also excludes regulatory liability adjustment (see Results of Operations below for further discussion).

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, changes in gas flows, regulatory actions, competition, weather and declines in the creditworthiness of our customers.

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. Although we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariffs, we frequently enter into firm transportation contracts at amounts that are less than these maximum rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems.

Our existing contracts mature at various times and in varying amounts of throughput capacity. We attempt to sell all of our capacity under long term contracts and market any remaining open positions under shorter term contracts as market demand permits. Currently, we face recontracting risk in certain of our market areas, particularly in the Rockies and Southwest region. In 2012, a significant amount of contracted capacity will expire on our EPNG system in the Southwest region. Certain customers who hold capacity on the EPNG system under contract terms of one year also hold renewal rights, and often renew their contracts on a year to year basis. We are currently remarketing the expiring capacity on our EPNG system to serve either its existing customers or to serve new customers. At this time, we are uncertain how much of the expiring capacity will be recontracted, and if so, at what rates.

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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, 2011, including those with terms beginning in 2012 or later. The weighted average remaining contract term for our active contracts is approximately six years as of December 31, 2011.

	Contracted Capacity BBtu/d	Percent of Total	Reservation Revenue	Percent of Total Reservation Revenue
			(In millions)	
2012	4,835	17	$ 291	12
2013	4,411	16	345	15
2014	2,626	9	235	10
2015	3,475	12	300	13
2016	2,087	8	187	8
2017 and beyond	10,493	38	980	42
Total	27,927	100	$ 2,338	100

Summary of Operational and Financial Performance

During 2011, we completed what was an $8 billion backlog of expansion projects, the largest in our company s history. Our Pipelines Segment EBIT for 2011 benefited primarily from expansion projects placed in service in 2010 and 2011 and higher rates on our TGP system effective June 1, 2011 due to its November 2010 rate case. More than offsetting the impact of these items when comparing to 2010 were non-cash losses in 2011 associated with the deconsolidation of Ruby in the third quarter of 2011. In addition, we had a gain on the sale of our Mexican pipeline and compression assets in 2010 with no comparable item in 2011. Expansion projects and related AFUDC was higher in 2010 when compared with 2009, but was partially offset by lower revenues on our EPNG and TGP systems.

Operating Results

	2011	2010	2009
	(In millions, except volumes)		
Operating revenues	$ 3,054	$ 2,820	$ 2,767
Operating expenses[(1)]	(2,234)	(1,517)	(1,486)
Operating income (loss)	820	1,303	1,281
Other income, net	315	435	200
Segment EBIT	$ 1,135	$ 1,738	$ 1,481
Throughput volumes (BBtu/d)[(2)]			
TGP	6,267	5,081	4,614
EPNG and MPC	3,132	3,395	3,982
CIG, WIC and CPG	4,901	5,189	5,550
SNG	2,463	2,505	2,322
Other		16	50
Equity investments[(3)]	1,580	1,372	1,820
Total throughput	18,343	17,558	18,338

(1) Includes losses associated with the deconsolidation of Ruby for the year ended December 31, 2011.
(2) Volumes exclude intrasegment activities.
(3) Represents our proportional share of unconsolidated affiliates.

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Below is a discussion of factors impacting Segment EBIT in 2011 compared with 2010 and 2010 as compared with 2009. We have also provided an outlook on events that could impact Segment EBIT in future periods.

	2011 to 2010 Variance				2010 to 2009 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 152	$ (50)	$ (49)	$ 53	$ 163	$ (29)	$ 149	$ 283
Reservation/usage revenues and expenses	96	(3)		93	(26)			(26)
Gas not used in operations	(65)	4		(61)	(77)	8		(69)
Regulatory liability adjustment	40			40				
Operating and general and administrative expense		(83)		(83)		23		23
Loss on deconsolidation of Ruby		(600)		(600)				
Asset sale/write downs		30	(79)	(49)		(33)	80	47
Other(1)	11	(15)	8	4	(7)		6	(1)
Total impact on Segment EBIT	$ 234	$ (717)	$ (120)	$ (603)	$ 53	$ (31)	$ 235	$ 257

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

Expansions. During 2011 and 2010, we benefited from increased reservation revenues due to placing a number of expansion projects in service, including (i) the WIC System expansion; (ii) Phase A of both the SLNG Elba Expansion III and Elba Express Pipeline Expansion projects; (iii) the CIG Raton 2010 Expansion; (iv) Phases I and II of the SNG South System III Expansion; (v) the Ruby pipeline project (prior to deconsolidation) and (vi) the TGP 300 Line expansion project. Partially offsetting these increases were depreciation and operating expenses associated with placing these projects in service as well as increased third party capacity commitments.

We capitalize a carrying cost (AFUDC) on funds related to our construction of long-lived assets and reflect these costs as increases to our other income on our income statements. Upon placing a project in service or pursuant to other regulatory requirements, we cease recording AFUDC on expansion projects. During the year ended December 31, 2011, our Segment EBIT was impacted by a decline of approximately $49 million as compared to 2010 primarily due to Ruby ceasing to record AFUDC in June 2011 based on an amendment of its FERC certificate which limited AFUDC accruals. However, we benefited from an increase in the equity portion of AFUDC of approximately $149 million during 2010 compared to 2009 primarily on our Ruby pipeline project, offset by AFUDC recorded on projects placed in service in 2010.

In addition to those projects we have placed in service as part of our $8 billion backlog of expansion projects, we anticipate placing the TGP Northeast Upgrade Project in service in November 2013 at an estimated cost of approximately $400 million. This project will provide 620 MMcf/d of additional firm transportation service from receipt points in the Marcellus shale basin to an interconnect in New Jersey. All of the firm transportation capacity is fully subscribed with two shippers under agreements executed during 2010. TGP filed a certificate application with the FERC in March 2011 and anticipates receiving approval in the first quarter of 2012.

Reservation/Usage Revenues and Expenses. Our reservation and usage revenues on each of our systems for the three year period ended December 31, 2011 were impacted by a number of factors, including regulatory actions, competition and changes in supply and demand, the more significant of which are noted below:

TGP. Our TGP system experienced an overall net increase in reservation and usage revenues of approximately $134 million for the year ended December 31, 2011 compared to 2010. The increase was primarily due to higher rates which became effective June 1, 2011 as a result of its November 2010 rate case and higher throughput volumes due to increased supply in the Haynesville and Marcellus shale basins. Partially offsetting these favorable impacts were lower usage revenues on certain interruptible services due to lower prices and basis differentials. When comparing 2010 to 2009, usage revenues were lower by approximately $12 million primarily due to a decrease in long-haul transports from a shift in receipts from the Gulf Coast region to the Rockies Express Pipeline interconnect in Ohio and Marcellus shale basin, which was short-haul transportation and subject to lower rates.

EPNG. Effective April 1, 2011, EPNG s rates were higher as a result of its September 2010 rate case. However, throughput volumes on our EPNG system continued to decline during 2011 and 2010. These declines were driven by a number of factors including, (i) reduced demand in the California market in 2011 due to high gas storage levels and increased hydroelectric generation, (ii) nonrenewal of certain expiring contracts, (iii) increased competition in the California and Arizona market areas and (iv) lower prices due to lower basis differentials related to certain interruptible services. The overall impact of these items to our Pipelines Segment EBIT was unfavorable in 2011 and 2010 by $10 million and $76 million when compared to prior periods.

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SNG. Nonrenewal of expiring contracts decreased Segment EBIT by $8 million during the year ended December 31, 2011 compared to 2010. Additionally, SNG s usage revenues were lower by $6 million primarily due to record weather conditions in the Southeast during 2010 as compared to 2011. When comparing 2010 to 2009, our Pipelines Segment EBIT was favorably impacted by $50 million primarily due to higher tariff rates effective September 1, 2009 due to SNG s rate case settlement.

CIG/WIC. For the year ended December 31, 2011 compared to 2010, reservation revenues on our CIG system were lower by $13 million due to increased competition in the Rockies region, nonrenewal of certain contracts and weak market conditions. Additionally, higher transportation expenses on our WIC and CIG systems of $3 million for the year ended December 31, 2011 negatively impacted 2011 results when compared to 2010 due to increased third party capacity commitments.

Gas Not Used in Operations. Effective June 1, 2011, TGP implemented a fuel volume tracker as part of its rate case filed with the FERC and as a result, no longer recognizes revenues associated with gas not used in operations which lowered our Pipelines Segment EBIT by $67 million for the year ended December 31, 2011. In addition, TGP implemented an electric compression tracker as part of its rate case which resulted in lower electric compression expenses of $11 million. The net unfavorable impacts associated with these operational activities are offset by higher reservation revenues discussed above. Prior to June 1, 2011, gas not used in operations on our TGP system resulted in revenues to us, which we recognized when the volumes were retained, valued at the market prices specified in our tariff. During 2011, we experienced lower prices coupled with lower retained fuel volumes in excess of fuel used in operations due to the shift in flow patterns and lower volumes on operational sales which unfavorably impacted our Segment EBIT by $10 million, partially offset by other gas sales of $8 million. During 2010, lower realized prices on operational sales contributed negatively to our Segment EBIT by $69 million when compared to 2009 partially offset by $15 million of lower electric compression.

Regulatory Liability Adjustment. As part of TGP s rate case settlement in December 2011, we recorded a reduction to our regulatory liabilities associated with our postretirement benefit plan and certain deferred taxes since these items were provided for under prior rate settlements and there is no funding requirement or cost recovery in our current rates for these items. See a further discussion of the TGP rate case, below under *Other Regulatory Matters*.

Operating and General and Administrative Expenses. During 2011, our Pipelines Segment experienced higher benefits and payroll costs and higher allocated corporate overhead costs based on the estimated level of resources devoted to the Pipelines Segment and other factors which negatively impacted our results by $43 million compared to 2010. Additionally, our Pipelines Segment EBIT was unfavorably impacted during 2011 by $26 million of increased contractor costs due to field repairs on our CIG and TGP pipeline systems and $7 million due to higher property taxes on several of our pipeline systems. During 2010, we experienced lower operating and general and administrative expenses when compared to 2009 primarily due to severance costs of approximately $14 million recorded in 2009.

Loss on Ruby Deconsolidation. In September 2011, upon meeting certain conditions of our partner and the lenders, we deconsolidated Ruby and began reflecting it as an investment in an unconsolidated affiliate. Subsequent to deconsolidation, Ruby s income (loss) is reflected in earnings from unconsolidated affiliates on our income statement. We reflect earnings from Ruby after interest, taxes and the preferred return of our partner. As a result of the deconsolidation of Ruby, we recorded a non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby and a non-cash loss of approximately $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt. For additional information on our Ruby pipeline project, see Item 8, Financial Statements and Supplementary Data, Note 18.

Asset Sale/Write Downs. During 2010, our Pipelines Segment EBIT was impacted by the following asset write-downs and sale: (i) a $21 million non-cash asset write-down in the third quarter based on a FERC order related to the sale of the Natural Buttes compressor station and gas processing plant in 2009; (ii) an impairment of approximately $10 million primarily related to a decision not to continue with a storage project due to market conditions; and (iii) a third quarter gain of approximately $80 million on the sale of our interests in certain Mexican pipeline and compression assets.

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Other Regulatory Matters. Our pipeline systems periodically file for changes in their rates, which are subject to 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, several of our pipelines have projected upcoming rate actions further described below.

EPNG Rate Case. In September 2010, EPNG filed a new rate case proposing an increase in its base tariff rates which would increase revenue by approximately $100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. A hearing commenced in late October 2011 and concluded in December 2011. A decision is due in May 2012. It is uncertain whether the requested increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of the hearing in the rate case. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In December 2011, the FERC approved TGP s settlement that resolved the outstanding issues arising from its general rate case filing. The settlement provides for, among other things, (i) an increase in TGP s base tariff rates effective June 1, 2011, (ii) implementation of cost trackers for fuel, pipeline safety and greenhouse gas, (iii) significant contract extensions to October 2014, (iv) a filing requirement for its next general rate case to be effective no earlier than April 2014 but no later than November 2015, and (v) a revenue sharing mechanism with certain of its customers for certain revenues above an annual threshold. In addition, as part of the settlement, TGP will refund approximately $68 million to its customers by March 31, 2012. We believe the accruals established for this matter are adequate.

CIG Rate Case. In August 2011, the FERC approved an uncontested pre-filing settlement of a rate case required under the terms of CIG s previous settlement. The settlement generally provides for (i) CIG s current tariff rates to continue until its next general rate case which will be effective no earlier than October 1, 2014 but no later than October 1, 2016; (ii) contract extensions to March 2016; (iii) a revenue sharing mechanism with certain of its customers for certain revenues above annual threshold amounts; and (iv) a revenue surcharge mechanism with certain of its customers to charge for certain shortfalls of revenue less than an annual threshold amount.

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Exploration and Production Segment

Overview and Strategy

Our exploration and production business is one of North America s leading independent oil, natural gas, and NGL producers focused on generating competitive financial returns through disciplined capital allocation and portfolio management, cost control and marketing and selling our oil and natural gas production at optimal prices while managing associated price risks. The profitability and performance of our business is driven by an ability to locate and develop economic oil and natural gas reserves and extract those reserves at the lowest possible production and administrative costs. Our strategy focuses on building and applying competencies in assets with repeatable programs, maximizing returns by adding assets, reserves and resources that match our competencies and divesting assets that do not and by executing to improve capital and expense efficiency.

Domestically, we operate through three divisions: Central, Western and Southern. The Central division includes operations in east Texas, Louisiana, Alabama, Indiana and eastern Oklahoma. Operations in our Western division are located in the Uintah Basin in Utah and the Raton Basin in New Mexico and Colorado. Our Southern division is located along the Gulf Coast, south and west areas of Texas and the Gulf of Mexico. Our core programs include the Haynesville Shale in northwest Louisiana and east Texas, the Altamont fractured tight sands in Utah, the Eagle Ford Shale in south Texas and the Wolfcamp Shale which is located in the Permian Basin of west Texas. Below is a description of each core program:

Haynesville. We operated approximately four rigs in the area through 2011 and are currently running one rig. Although we have a very efficient drilling program in the Haynesville Shale, we plan to shut down the program due to low natural gas prices. We expect to release all rigs by the end of the first quarter of 2012 and we plan to redeploy the capital allocated to Haynesville to our oil programs.

Altamont. In the Altamont area, we are gaining operational efficiencies as we develop the field. We ran approximately three rigs through 2011. Currently, we are running two rigs.

Eagle Ford. The Eagle Ford oil program has the most economic potential in our portfolio at current prices, with approximately 60 percent of our acreage in the liquids rich area of the shale play. We are currently running four rigs.

Wolfcamp. In our Wolfcamp program, which we entered in 2010, we are focused on optimizing our drilling, completion, hydraulic fracturing designs, and artificial lift systems. We are currently running one rig.

Internationally, our portfolio consists of producing fields along with exploration and development projects in offshore Brazil and exploration projects in Egypt. Success of our international programs in Brazil and Egypt will require effective project management, strong partner relations and obtaining approvals from regulatory agencies.

Our exploration and production operations generate profits dependent on the prices for oil and natural gas, the costs to explore, develop, and produce oil and natural gas, and the volumes we are able to produce, among other factors. Our long-term profitability will be primarily influenced by the following factors:

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

In addition to these factors, our future profitability and performance will be affected by our ability to execute our strategy, the impacts of volatility in the financial and commodity markets, industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating and capital costs, our debt level and related interest costs. Additionally we may be impacted by hurricanes and other weather events, domestic or international regulatory issues or other actions outside of our control (e.g., oil spills). To the extent possible, we attempt to mitigate certain of these risks through actions, such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

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Significant Operational Factors Affecting the Year Ended December 31, 2011

Volumes. Our volumes by commodity for the years ended December 31 were as follows:

	2011	2010	2009
Natural Gas (MMcf/d)			
Consolidated volumes	661	618	599
Unconsolidated affiliate volumes	46	47	54
Total Combined	707	665	653
Oil and condensate (MBbls/d)			
Consolidated volumes	16	13	11
Unconsolidated affiliate volumes	1	1	1
Total Combined	17	14	12
NGL (MBbls/d)			
Consolidated volumes	3	4	5
Unconsolidated affiliate volumes	1	2	2
Total Combined	4	6	7
Equivalent Volumes (MMcfe/d)			
Consolidated volumes	777	720	691
Unconsolidated affiliate volumes	61	62	72
Total Combined	838	782	763

Production. Our average daily production volumes for the year ended December 31, 2011 were 838 MMcfe/d, including 61 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the years ended December 31:

	2011	2010 (MMcfe/d)	2009
United States			
Central	422	338	269
Western	154	160	154
Southern[(1)]	167	189	256
International			
Brazil	34	33	12
Total consolidated	777	720	691
Four Star	61	62	72
Total combined	838	782	763

(1) In 2011, our Gulf Coast division was renamed the Southern division, and we made minor changes to the properties contained within our various domestic operating divisions. Divisional amounts for prior periods have been adjusted to reflect these changes.

Central division Our 2011 Central division production volumes continued to increase as a result of our successful drilling programs in the Haynesville Shale. As of December 31, 2011, we had 108 operated wells and our total average production for 2011 was approximately 265 MMcfe/d. In addition, in south Louisiana we are developing our emerging Wilcox program. This is a relatively new oil play we have added to our drilling program. As of December 31, 2011, we had 14 operated wells related to our Wilcox program.

Western division Our 2011 Western division production volumes decreased compared to 2010 due to divestitures in the Rockies program and natural declines in the County Line program offset by increased production volumes in our Altamont and Raton programs. As of December 31, 2011 our Altamont program had 289 net operated wells with total oil production of approximately 7 MBbls/d.

Southern division Our 2011 Southern division production volumes decreased primarily due to natural declines and lower levels of drilling activity in the Texas Gulf Coast and Gulf of Mexico areas. In this division, we continue to focus on our Eagle Ford Shale activity. As of December 31, 2011 we had a total of 64 operated wells and these wells are located principally in the liquids rich area of the Eagle Ford Shale. For 2011, our total oil and NGL production was approximately 5 MBbls/d related to Eagle Ford. We also continue to assess our Wolfcamp Shale area, having drilled 13 wells during 2011.

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International Our 2011 production volumes in Brazil increased due to production from our Camarupim Field where a fourth well in the field began production. During 2011, we were informed that our environmental permit request for the Pinauna Field in the Camamu Basin was denied by the Brazilian environmental regulatory agency. As a result, we released $94 million of unevaluated capitalized costs related to this field into the Brazilian full cost pool. We have filed an appeal and are awaiting a response. Additionally, during 2011, we released approximately $86 million of unevaluated capitalized costs related to the ES-5 block in the Espirito Santo Basin upon the completion of our evaluation of exploratory wells drilled in 2009 and 2010 without any additions to our proved reserves. We will continue to pursue alternatives for the hydrocarbons discovered in these areas. During 2011, due to political unrest in Egypt we experienced a delay in obtaining governmental approval of a new partner in our South Alamein block and postponed drilling in South Mariut. We expect these matters to be resolved in 2012 and we continue to evaluate the commerciality of these areas. At December 31, 2011, we have total oil and natural gas capitalized costs of approximately $205 million and $74 million in Brazil and Egypt, of which $8 million and $74 million are unevaluated capitalized costs.

Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas 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 our Exploration and Production segment, however, this measure may not be comparable to those used by other companies.

During the year ended December 31, 2011, cash operating costs per unit increased slightly to $1.79/Mcfe as compared to $1.78/Mcfe in 2010. The increase in 2011 on a per unit basis, is primarily due to higher lease operating expenses and production taxes, offset by higher production volumes.

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

(1) Reserve additions include proved reserves and reflect reserve revisions 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 Oil and Natural Gas Operations.

(2) Total oil and natural 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 Oil and Natural Gas 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 oil and natural gas 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, 2011, proved developed reserves represent approximately 50 percent of our total consolidated proved reserves. Proved developed reserves will generally begin producing within the year they are added, whereas proved undeveloped reserves generally require additional future expenditures.

The table below shows our reserve replacement ratio and reserve replacement costs 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		
	2011	2010	2009	2011	2010	2009
		($/Mcfe)			($/Mcfe)	
Reserve Replacement Ratios						
Domestic						
Including acquisitions	416%	370%	188%	418%	306%	220%
Excluding acquisitions	416%	353%	162%	418%	289%	195%
Worldwide						
Including acquisitions	400%	347%	212%	401%	284%	245%

Excluding acquisitions	400%	331%	187%	401%	268%	220%
Reserve Replacement Costs [(1)]						
Domestic						
Including acquisitions	$ 1.42	$ 1.29	$ 1.84	$ 1.41	$ 1.56	$ 1.57
Excluding acquisitions	1.42	1.29	1.91	1.41	1.58	1.59
Worldwide						
Including acquisitions	$ 1.43	$ 1.40	$ 2.04	$ 1.43	$ 1.72	$ 1.76
Excluding acquisitions	1.43	1.41	2.13	1.43	1.75	1.81

(1) Only proved property acquisition costs are excluded from these calculations. Leasehold or unproved acquisitions costs are included in all calculations.

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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, 2011.

	Including Price Revisions	Excluding Price Revisions
	Three Years Ending December 31, 2011 ($/Mcfe)	
Reserve Replacement Costs		
Domestic		
Including acquisitions	$ 1.45	$ 1.49
Excluding acquisitions	1.45	1.50
Worldwide		
Including acquisitions	$ 1.55	$ 1.60
Excluding acquisitions	1.56	1.61

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

	2011	2010	2009
		(In millions)	
Total oil and natural gas capital costs, excluding proved property acquisitions	$ 1,624	$ 1,231	$ 1,004
Proved property acquisitions		51	87
Total oil and natural gas capital costs, including acquisitions(1)	$ 1,624	$ 1,282	$ 1,091
Non oil and natural gas capital costs	20	36	38
Total capital expenditures	$ 1,644	$ 1,318	$ 1,129

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

Capital expenditures and average rig count by core program for the year ended December 31, 2011 were:

	Capital Expenditures (In millions)	Rig Count
Haynesville	$ 409	4
Altamont	173	3
Eagle Ford	626	3
Wolfcamp	163	2
Other, including International	273	1
Total capital expenditures	$ 1,644	13

Price Risk Management Activities

We enter into derivative contracts on our oil and natural gas production primarily to stabilize cash flows, and reduce the risk and financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge all of our price risks, 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 2011, approximately 80 percent of our natural gas production and 95 percent of our crude oil production were economically hedged at average floor prices of $5.83 per MMBtu and $85.99 per barrel, respectively.

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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, 2011.

	2012		2013		2014	
	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]
Natural Gas						
Fixed Price Swaps	105	$ 6.01		$		$
Oil						
Fixed Price Swaps	640	$ 100.13		$		$
Ceilings	1,464	$ 95.00	2,920	$ 96.88	1,095	$ 100.00
Three Way Collars Ceilings	5,764	$ 114.16	1,552	$ 128.34		$
Three Way Collars Floors[(2)]	5,764	$ 92.54	1,552	$ 100.00		$

(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) If market prices settle at or below $67.54 and $75.00 for the years 2012 and 2013, respectively, our three-way collars-floors effectively lock-in a cash settlement of the market price plus $25.00 per Bbl for 2012 and 2013.

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:

	2011	2010 (In millions)	2009
Physical sales:			
Natural gas	$ 973	$ 974	$ 830
Oil and condensate	552	346	214
NGL	57	60	53
Total physical sales	1,582	1,380	1,097
Realized and unrealized gains on financial derivatives[(1)]	284	390	687
Other revenues	1	19	44
Total operating revenues	1,867	1,789	1,828
Operating expenses			
Cost of products		15	31
Transportation costs	85	73	66
Production costs	298	264	252
Depreciation, depletion and amortization	612	477	440
General and administrative expenses	201	190	195
Ceiling test charges	152	25	2,123
Impairment of inventory and other assets	6		25
Other	10	14	13
Total operating expenses	1,364	1,058	3,145
Operating income (loss)	503	731	(1,317)
Other income (expense)[(2)]	(9)	(4)	(32)

Segment EBIT	$ 494	$ 727	$ (1,349)

(1) Includes $11 million, $11 million and $406 million for the years ended December 31, 2011, 2010 and 2009, reclassified from accumulated other comprehensive income associated with accounting hedges.

(2) Other income (expense) 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.

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The table below provides additional detail of our volumes, prices, and costs per unit. We present (i) average realized prices based on physical sales of oil and condensate, natural gas and NGL as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements. Our average realized prices, including financial derivative settlements, reflect cash received and/or paid during the period on settled financial derivatives based on the period the contracted settlements were originally scheduled to occur; however, these prices do not reflect the impact of any associated premiums paid to enter into certain of our derivative contracts.

	2011	2010	2009
Volumes:			
Oil and condensate			
Consolidated volumes (MBbls)	6,034	4,747	4,078
Unconsolidated affiliate volumes (MBbls)	306	364	419
Natural gas			
Consolidated volumes (MMcf)	241,083	225,611	218,544
Unconsolidated affiliate volumes (MMcf)	16,881	17,165	19,557
NGL			
Consolidated volumes (MBbls)	1,068	1,423	1,570
Unconsolidated affiliate volumes (MBbls)	556	573	678
Equivalent volumes			
Consolidated MMcfe	283,696	262,631	252,432
Unconsolidated affiliate MMcfe	22,052	22,787	26,139
Total combined MMcfe	305,748	285,418	278,571
Consolidated MMcfe/d	777	720	691
Unconsolidated affiliate MMcfe/d	61	62	72
Total Combined MMcfe/d	838	782	763
Consolidated prices and costs per unit:			
Oil and condensate			
Average realized price on physical sales ($/Bbl)	$ 91.40	$ 72.83	$ 52.48
Average realized price, including financial derivative settlements ($/Bbl)(1)(2)	$ 90.23	$ 71.13	$ 95.57
Average transportation costs ($/Bbl)	$ 0.06	$ 0.08	$ 0.06
Natural gas			
Average realized price on physical sales ($/Mcf)	$ 4.04	$ 4.32	$ 3.80
Average realized prices, including financial derivative settlements ($/Mcf)(1)(2)	$ 5.44	$ 5.67	$ 7.62
Average transportation costs ($/Mcf)	$ 0.33	$ 0.30	$ 0.28
NGL			
Average realized price on physical sales ($/Bbl)	$ 53.50	$ 42.38	$ 33.75
Average transportation costs ($/Bbl)	$ 3.83	$ 3.16	$ 2.61
Cash operating costs ($/Mcfe)			
Average lease operating expenses	$ 0.77	$ 0.73	$ 0.78
Average production taxes(3)	0.28	0.27	0.22
Average general and administrative expenses	0.70	0.72	0.77
Average taxes, other than production and income taxes	0.04	0.06	0.05
Total cash operating costs	$ 1.79	$ 1.78	$ 1.82
Depreciation, depletion and amortization ($/Mcfe)(4)	$ 2.16	$ 1.82	$ 1.74

(1) We had no cash premiums related to oil derivatives settled during the years ended December 31, 2011, 2010 and 2009. Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2011 were $23 million. Had we included these premiums in our natural gas average realized prices in 2010 and 2011, our realized price, including financial derivative settlements, would have decreased by $0.70/Mcf and $0.10/Mcf for the years ended December 31, 2010 and 2011.

(2) The years ended December 31, 2011, 2010 and 2009, include approximately $338 million, $306 million and $834 million of cash receipts for the settlement of natural gas derivative contracts. The years ended December 31, 2011 and 2010, include approximately $7 million and $8 million of cash paid for the settlement of crude oil derivative contracts. Additionally, the year ended December 31, 2009, includes approximately $176 million of cash receipts for the settlement of crude oil derivative contracts.

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

(4) Includes $0.05 per Mcfe for the year ended December 31, 2011, and $0.06 per Mcfe for each of the years ended December 31, 2010 and 2009 related to accretion expense on asset retirement obligations.

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Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Our Segment EBIT for 2011 decreased $233 million as compared to 2010. The table below shows the significant variances in our financial results in 2011 as compared to 2010:

	Variance			
	Operating Revenue	Operating Expense	Other	Segment EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Lower realized prices in 2011	$ (68)	$	$	$ (68)
Higher volumes in 2011	67			67
Oil and condensate				
Higher realized prices in 2011	112			112
Higher volumes in 2011	94			94
NGL				
Higher realized prices in 2011	12			12
Lower volumes in 2011	(15)			(15)
Realized and unrealized gains(losses) on financial derivatives	(106)			(106)
Other revenues	(18)			(18)
Depreciation, depletion and amortization expense				
Higher depletion rate in 2011		(98)		(98)
Higher production volumes in 2011		(37)		(37)
Production costs				
Higher lease operating expenses in 2011		(24)		(24)
Higher production taxes in 2011		(10)		(10)
General and administrative expenses		(11)		(11)
Ceiling test charges		(127)		(127)
Earnings from investment in Four Star				
Other		1	(5)	(4)
Total Variances	$ 78	$ (306)	$ (5)	$ (233)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During 2011, our revenues increased as compared with 2010 due primarily to higher oil and natural gas volumes and higher oil and condensate prices, partially offset by lower natural gas prices. The higher volumes are due to our focus on our core programs in the Haynesville and Eagle Ford shales.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2011, we recognized net gains of $284 million compared to net gains of $390 million during 2010. Gains or losses each period are due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

Depreciation, depletion and amortization expense. During the year ended December 31, 2011, our depreciation, depletion and amortization expense increased as a result of higher depletion rate and higher production volumes compared to the same period in 2010. Our depreciation, depletion and amortization rate increased in 2011 as we focused our capital on oil programs.

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Production costs. Our production costs increased during 2011 as compared to 2010 primarily due to higher lease operating expenses and higher production taxes mainly associated with higher volumes. Lease operating expenses increased due to higher maintenance, repair and power costs in our Western division, temporary higher costs in our Southern division due to early well testing and higher expenses in our International division.

General and administrative expenses. Our general and administrative expenses increased during 2011 as compared to the same period in 2010 due to severance costs related to an office closure and higher employee benefit costs.

Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the year ended December 31, 2011 we recorded a non-cash ceiling test charge of approximately $152 million in our Brazilian full cost pool. The ceiling test charge was driven by the release of costs into the Brazilian full cost pool substantially due to the denial of a necessary environmental permit on our Pinauna project as well as the completion of our evaluation of certain exploratory wells drilled in 2009 and 2010. We have filed an appeal with regard to the denial of the permit and are awaiting a response. During the year ended December 31, 2010, we recorded non-cash ceiling test charges of $25 million to our Egyptian full cost pool as a result of acreage relinquishments in South Mariut and South Alamein and a dry hole drilled in the Tanta block. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. In the future, we may incur ceiling test charges in Egypt depending on the results of our activities in that country. Due to political unrest in Egypt during 2011, we experienced a delay in governmental approval of a new partner in our South Alamein block and postponed drilling in South Mariut. We expect these matters to be resolved in 2012 and we continue to evaluate the commerciality of these areas.

Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. A sustained period of low domestic natural gas prices will over time result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our proved reserves, which could result in ceiling test charges on our domestic full cost pool. In addition, the fair value of our investment in Four Star could decline as a result of lower natural gas prices and we may be required to record an impairment of the carrying value in the future.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Our Segment EBIT for 2010 increased $2.1 billion as compared to 2009. The table below shows the significant variances in our financial results in 2010 as compared to 2009:

	Variance			
	Operating Revenue	Operating Expense	Other	Segment EBIT
		Favorable/(Unfavorable) (In millions)		
Physical sales				
Natural gas				
Higher realized prices in 2010	$ 117	$	$	$ 117
Higher volumes in 2010	27			27
Oil and condensate				
Higher realized prices in 2010	97			97
Higher volumes in 2010	35			35
NGL				
Higher realized prices in 2010	12			12
Lower volumes in 2010	(5)			(5)
Realized and unrealized gains on financial derivatives	(297)			(297)
Other revenues	(25)			(25)
Depreciation, depletion and amortization expense				
Higher depletion rate in 2010		(20)		(20)
Higher production volumes in 2010		(17)		(17)
Production costs				
Lower lease operating expenses in 2010		4		4
Higher production taxes in 2010		(16)		(16)
General and administrative expenses		5		5
Ceiling test charges		2,098		2,098
Impairment of inventory and other assets		25		25

Earnings from unconsolidated affiliate			23	23
Other		8	5	13
Total variances	$ (39)	$ 2,087	$ 28	$ 2,076

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During 2010, revenues increased as compared with 2009 due primarily to higher commodity prices. During the year ended December 31, 2010, we also benefited from an increase in production volumes in our Central and Western divisions and in Brazil.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2010, we recognized net gains of $390 million compared to net gains of $687 million during 2009. Gains or losses each period are based on movements of forward commodity prices relative to the prices in our underlying financial derivative contracts.

Depreciation, depletion and amortization expense. During the year ended December 31, 2010, our depreciation, depletion and amortization expense increased as compared to the same period in 2009 as a result of higher depletion rate and higher production volumes. For the year ended December 31, 2009 depletion rate was largely impacted by the ceiling test charges recorded in the first quarter of 2009.

Production costs. Our production costs increased during 2010 as compared to 2009 primarily due to higher production taxes which increased due to higher oil and natural gas revenues.

General and administrative expenses. Our general and administrative expenses decreased during 2010 as compared to the same period in 2009 primarily due to lower payroll and administrative costs to support the business following reorganizations in 2009.

Ceiling test charges. During the year ended December 31, 2010, we recorded non-cash ceiling test charges of $25 million to our Egyptian full cost pool as a result of contractual acreage relinquishments in our blocks, and a dry hole drilled in the Tanta block. During the year ended December 31, 2009, we recorded non-cash ceiling test charges of $2.1 billion to our domestic and Brazilian full cost pools as a result of low oil and natural gas prices and to our Egyptian full cost pool as a result of dry hole costs.

Other. Our equity earnings from Four Star in 2010 increased by $23 million as compared to 2009 primarily due to the impact of higher commodity prices partially offset by lower production volumes.

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Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s oil and natural gas production and to manage El Paso s overall price risk, including legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. This segment also has agreements with our midstream joint venture to market the natural gas and natural gas liquids production from its Utah operations. All of our contracts are subject to counterparty credit and non-performance risks while our remaining mark-to-market contracts are also subject to interest rate exposure. Revenues of our Marketing activities are recorded net of related costs.

Natural gas transportation-related contracts. The impact of these accrual-based transportation contracts is based on our ability to use or remarket the contracted pipeline capacity and the amount of production from our Exploration and Production segment. As of December 31, 2011, these contracts require us to pay demand charges of $56 million in 2012 and an average of $31 million per year between 2013 and 2016.

Legacy natural gas and power contracts. As of December 31, 2011, these contracts include (i) long-term accrual based supply contracts, including transportation expenses, that obligate us to deliver natural gas to specified power plants and (ii) power contracts in the PJM region through 2016, which we mark-to-market in our results. These contracts are expected to have minimal future earnings impact to us as we have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

Operating Results

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

	2011	2010	2009
		(In millions)	
Income (Loss):			
Contracts Related to Legacy Trading Operations:			
Accrual-based contracts (including natural gas transportation):			
Demand charges	$ (52)	$ (37)	$ (35)
Settlements, net of termination payments	8	33	23
Changes in fair value of other natural gas derivative contracts	(3)	(10)	(3)
Changes in fair value of power contracts	(8)	(35)	44
Total revenues	(55)	(49)	29
Operating expenses	(6)	(2)	(9)
Operating income (loss)	(61)	(51)	20
Other income, net		1	
Segment EBIT	$ (61)	$ (50)	$ 20

During the year ended December 31, 2011 demand charges increased primarily due to increases in transport tariff rates on existing contracts. We recorded a $22 million loss on the settlement of an affiliated fuel supply agreement which was terminated in June 2011 and reflected as a component of settlements, net of termination payments, from accrual-based contracts. During the years ended December 31, 2011, 2010 and 2009, our results were also impacted by changes in the fair value of our legacy power contracts in PJM. At the end of 2010, we entered into contracts that eliminated the price risks associated with our PJM power contracts. Based on these actions, changes in the fair value of our legacy power contracts occuring in 2011 were primarily a result of changes in interest rates and credit risk. These items may also impact future earnings related to these contracts. During 2009 we recorded 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 a $27 million loss related to the impact of El Paso s credit standing on our derivative liabilities.

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Other Activities

Our other activities include our midstream operations (as further discussed in Part I, Item 1, Business), corporate general and administrative functions and other miscellaneous businesses.

The following is a summary of significant items impacting the Segment EBIT in our other activities for each of the three years ended December 31:

	$(217)	$(217)	$(217)
	2011	**2010**	**2009**
		(In millions)	
Income (Loss)			
Loss on debt extinguishment	$ (169)	$ (217)	$
Change in environmental, legal and other reserves	(58)	(20)	(2)
Midstream	5	117	
Net earnings (losses) related to legacy investments	35	37	19
Other	(56)	9	(34)
Total Segment EBIT	$ (243)	$ (74)	$ (17)

Loss on Debt Extinguishment. During 2011 and 2010, we incurred losses primarily related to the repurchase or exchange of approximately $1.0 billion and $1.1 billion of senior unsecured notes.

Environmental, Legal and Other Reserves. We have a number of pending litigation matters and reserves related to our historical business operations that affect our results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may continue to impact our future results. Our results for all periods presented were primarily impacted by adjustments to certain legacy environmental matters, including a non-operated chemical plant and a non-operated refinery in south Texas. Also impacting these results were adjustments to certain legacy indemnifications, including an indemnification on which our liability fluctuates with ammonia prices.

Midstream. In December 2010, we recorded a gain of $110 million in conjunction with the sale of a 50 percent interest in our new midstream joint venture which is comprised of our Altamont gathering and processing midstream assets for $125 million in cash. We own a 50 percent interest in and operate the joint venture which is accounted for as an equity investment.

Net Earnings (Losses) Related to Legacy Investments. We have equity investments and receivables related to our legacy foreign power, telecommunications and other operations, certain of which are impacted by foreign currency fluctuations. During 2011, our results were also impacted by a $16 million gain on the sale of our remaining interest in a telecommunications equity investment. During 2009, our results were impacted by a $22 million loss associated with the sale of notes receivable related to a legacy power investment.

Other. Our results are impacted by other items including benefit costs associated with certain of our post-retirement and other benefit plans. During 2011, our results were also impacted by $20 million of costs associated with the previously announced spin-off of our Exploration and Production operations and costs related to our anticipated merger with Kinder Morgan. During 2010, our results were impacted by $40 million of income due to the receipt of funds previously escrowed and expensed in conjunction with The Coastal Corporation merger in 2001.

Interest and Debt Expense

Our interest and debt expense for the years ended December 31, 2011, 2010 and 2009 was $0.9 billion, $1.0 billion and $1.0 billion. Our interest and debt expense decreased during the year ended December 31, 2011 as compared to 2010 primarily associated with the exchange or repurchase of approximately $2.1 billion of debt in 2010 and 2011 with rates from 6.875 percent to 12 percent. Interest savings associated with these transactions have been partially offset by interest costs on new borrowings.

Our interest and debt expense was flat in 2010 compared to 2009 primarily due to increases in Ruby pipeline project and other financings, net of higher AFUDC debt associated with the Ruby project. Additionally, in 2010 we were impacted by changes in our estimates of the allowance for funds used during construction and an increase in the interest rate from 7 percent to 13 percent on the Ruby term loan.

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Income Taxes

	Years Ended December 31,		
	2011	2010	2009
		(In millions)	
Income tax expense (benefit)	$ (50)	$ 386	$ (399)
Effective tax rate	(13)%	29%	46%

Our negative effective tax rate for the year ended December 31, 2011 reflects (i) the impact of a low level of pretax income, (ii) a $71 million deferred state tax benefit recorded upon the conversion of a subsidiary to a limited liability company which reduced state effective tax rates and (iii) the favorable resolution of certain tax matters. Partially offsetting these items is a $53 million tax impact of a Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit (deferred Brazilian tax benefits offset by an equal valuation allowance). Absent all of these items, our effective tax rate for the year ended December 31, 2011 would have been 24 percent which is well below the statutory rate due to income attributable to nontaxable noncontrolling interests. For a further discussion on our effective tax rate, refer to Item 8, Financial Statements and Supplementary Data, Note 5.

Commitments and Contingencies

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

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Liquidity and Capital Resources

Overview. Our primary sources of cash include cash flow from operations and funds obtained through long term financings, including capital market activities (e.g. executing on financings utilizing our master limited partnership) and bank credit facilities. We also generate cash through project financings and asset sales when warranted. We do not typically rely on short-term borrowings to fulfill our liquidity needs. Our primary uses of cash are funding capital expenditures, meeting operating needs, paying distributions and dividends and repaying debt when due or repurchasing debt when conditions warrant.

During 2011, we completed the remainder of our $8 billion backlog of expansion projects, the largest in our company s history, while continuing to support our exploration and production program. In July 2011, we placed the Ruby pipeline project in service and, upon making certain permitting representations and meeting certain other conditions, El Paso s guarantee of GIP s $700 million investment in Ruby and Cheyenne Plains (an entity that owns our Cheyenne Plains pipeline) expired and the Ruby project financing obligations became non-recourse to us. As a result, we deconsolidated Ruby. For a further description of this project and our agreement with GIP, see Item 8, Financial Statements and Supplementary Data, Note 18.

Available Liquidity. As of December 31, 2011 we had approximately $0.9 billion of available liquidity (exclusive of cash and credit facility capacity of EPB). During 2011, we (i) generated operating cash flow of approximately $2.1 billion, (ii) spent approximately $3.8 billion primarily in our capital programs, (iii) refinanced approximately $3.25 billion of our revolving credit facilities to extend these maturities to 2016 and (iv) received approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our MLP which funded the acquisitions primarily through the issuance of common units and debt. In July 2011, our $500 million unsecured credit facility matured and in December 2011, we allowed our $300 million EP Energy Corporation (EPE) borrowing base credit facility to mature.

Pursuant to the merger agreement with KMI, we are subject to certain conditions, restrictions and thresholds, including our ability to refinance or incur new debt, issue El Paso capital stock and/or dispose of any material properties, assets, or equity interests other than as prescribed in the merger agreement. However, as a result of our current available liquidity and the hedging program we have in place on our oil and natural gas production, we expect our current liquidity sources and operating cash flow to be sufficient to fund our working capital requirements, estimated 2012 capital expenditures and approximately $362 million of 2012 debt maturities. We will continue to assess and take further actions where prudent and in the ordinary course of business to meet our capital requirements as well as address further changes in the financial and commodity markets. However, there are a number of factors that could impact our future plans including, but not limited to, completion of our proposed merger with KMI or a further decline in commodity prices. If these events occur, or fail to occur, additional adjustments to our plan may be required, including reductions in our discretionary capital program or reductions in operating and general and administrative expenses, all of which could impact our financial and operating performance.

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Overview of 2011 Cash Flow Activities. During 2011, we generated operating cash flow of approximately $2.1 billion, primarily from our pipeline and exploration and production operations. We also generated (i) approximately $0.7 billion from asset sales, primarily non-core oil and natural gas properties, (ii) approximately $0.9 billion as a result of the issuance of MLP common units and (iii) approximately $5.9 billion through the issuance of debt and borrowings under revolving credit facilities. We utilized these amounts to fund our capital programs (including completing our Ruby project in July 2011) and investments, repay amounts outstanding under our various credit facilities and other debt obligations, and pay common and preferred dividends and distributions to our MLP unitholders and holders of our subsidiary preferred stock, among other items. For a further description of Ruby, see Item 8, Financial Statements and Supplementary Data, Notes 11 and 18. For the year ended December 31, 2011 and 2010, our cash flows from operations are summarized as follows:

	2011	2010
	(In billions)	
Cash Flow from Operations		
Operating activities		
Net income	$ 0.4	$ 0.9
Ceiling test charges	0.2	
Loss on deconsolidation of subsidiary	0.6	
Other income adjustments	1.1	1.2
Change in other assets and liabilities	(0.2)	(0.4)
Total cash flow from operations	$ 2.1	$ 1.7
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets and investments	$ 0.7	$ 0.5
Financing activities		
Net proceeds from the issuance of long-term debt	5.9	3.4
Net proceeds from issuance of noncontrolling interests	0.9	1.3
Other	0.1	0.1
	6.9	4.8
Total other cash inflows	$ 7.6	$ 5.3
Cash Outflows		
Investing activities		
Capital expenditures and contributions to equity investments	$ 3.8	$ 4.0
Other	0.2	
	4.0	4.0
Financing activities		
Payments to retire long-term debt and other financing obligations	5.7	3.1
Distribution to noncontrolling interest holders	0.2	0.1
Dividends and other		0.1
	5.9	3.3
Total cash outflows	$ 9.9	$ 7.3
Net change in cash and cash equivalents	$ (0.2)	$ (0.3)

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 $710 million, which is comprised of a $438 million indemnification associated with the sale of ANR, a $120 million indemnification associated with the sale of our Macae power facility in Brazil, and $152 million of indemnifications and guarantees related to the sale of other legacy assets. During the fourth quarter of 2011, we received a full claim against our Macae indemnification for matters that we believe are specifically excluded from the scope of the indemnification. These amounts exclude guarantees for which we have issued related letters of credit discussed below. 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, 2011, we have recorded obligations of $15 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, 2011, we had outstanding letters of credit and surety bonds of approximately $0.6 billion, including $0.3 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, 2011.

Interests in Variable Interest Entities

We have interests in variable interest entities which are legal entities whose equity owners do not have sufficient equity at risk or characteristics of a controlling financial interest in the entities. We are required to consolidate such entities when we have the ability to control or direct the operating and financial decisions or other activities that are significant to that entity. As of December 31, 2011, there were no significant variable interest 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, capital commitments and contractual interest amounts are not reflected on our balance sheet. The following table and discussion summarizes our contractual cash obligations as of December 31, 2011, for each of the periods presented:

	Due in Less than 1 Year	Due in 1 to 3 Years	Due in 3 to 5 Years (In millions)	Thereafter	Total
Long-term financing obligations:					
Principal	$ 362	$ 543	$ 2,692	$ 9,415	$ 13,012
Interest	871	1,670	1,478	6,406	10,425
Liabilities from price risk management activities	140	189	95		424
Other contractual liabilities	125	65	21	21	232
Operating leases	14	26	16	8	64
Other contractual commitments and purchase obligations:					
Transportation and storage	132	239	242	537	1,150
Other	162	81	55	209	507
Total contractual obligations	$ 1,806	$ 2,813	$ 4,599	$ 16,596	$ 25,814

Long-term Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt or (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 11.

Liabilities from Price Risk Management Activities. These amounts only include the fair value of our price risk management liabilities. The fair value of our price risk management assets of $302 million as of December 31, 2011 is not reflected in these amounts. We have also excluded margin and other deposits held associated with these contracts from these amounts. We net our derivative assets and liabilities for counterparties where we have a legal right of offset. For a further discussion of our price risk management activities, see Item 8, Financial Statements and Supplementary Data, Note 7.

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 fixed as to time and amount. For further information on our expected contributions to our pension and post retirement benefit plans, see Item 8, Financial Statements and Supplementary Data, Note 13. We have also excluded from these amounts liabilities for unrecognized tax benefits of $266 million as of December 31, 2011, 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 12.

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. Included are the following:

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

Other Commitments. Included in these amounts are commitments for 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 12. 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.

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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 Oil and Natural Gas Producing Activities. Our estimates of proved reserves reflect quantities of oil, natural gas 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 oil and natural gas 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, 2011.

As of December 31, 2011, of our total consolidated proved reserves, 50 percent were undeveloped (49 percent including Four Star) and 9 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 oil and natural gas reserves primarily impact our property, plant and equipment amounts on our balance sheets and the depreciation, depletion and amortization amounts and any ceiling test charges on our income statements, among other items. We use the full cost method to account for our oil and natural gas producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the acquisition, exploration and development of oil and natural gas 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, Oil and Natural Gas Properties.

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Oil and natural gas 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. For a further discussion of these costs by country, see Part II, Item 8, Financial Statements and Supplementary Data, Supplemental Oil and Natural Gas Operations.

Under the full cost accounting method for oil and natural gas 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 less estimated future capital expenditures, discounted at 10 percent, plus the cost of unproved oil and natural gas properties not being amortized less related income tax effects. We are required to use a first day 12-month average price in calculating the ceiling test and estimating proved reserves. 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 evaluate our assets for impairment and write-off the associated regulatory assets.

Accounting for Environmental and Legal Reserves, Guarantees and Indemnifications. We accrue environmental and legal reserves when our assessments indicate that it is probable that a liability has been incurred 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, 2011, we had accrued approximately $38 million for all of our outstanding legal proceedings and approximately $181 million for environmental matters, which has not been reduced by $18 million for amounts to be paid directly under government sponsored programs or through settlement arrangements. Our environmental estimates range from approximately $181 million to approximately $321 million and the lower end of the expected range has been accrued.

We also have guarantee and indemnification agreements related to various joint ventures and other ownership arrangements that require us to assess our potential exposure. This exposure can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $0.7 billion. As of December 31, 2011, we have recorded obligations of $15 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, 2011, our pension plans were under funded by $418 million and our other postretirement benefit plans were under funded by $321 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 expected future lives of inactive plan participants. We record these deferred amounts as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations. As of December 31, 2011, we had deferred net losses of approximately $751 million, net of income taxes, in accumulated other comprehensive income related to our pension and other postretirement benefits. 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, 2011 (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	$ (6)	$ 188	$ 1	$ 50
Expected return on plan assets	(18)		(3)	
Rate of compensation increase	2	(8)		
Health care cost trends			3	(47)
One percent decrease in:				
Discount rates	$ 6	$ (221)	$ (2)	$ (59)
Expected return on plan assets[1]	18		3	
Rate of compensation increase	(1)	7		
Health care cost trends			(3)	41

(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 fully recognized for purposes of determining 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 $25 million lower for the year ended December 31, 2011.

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

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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 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, 2011:

		Change in Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 201	$ 88	$ (113)	$ 303	$ 102
Other commodity-based derivatives	(311)	(309)	2	(312)	(1)
Total	$ (110)	$ (221)	$ (111)	$ (9)	$ 101

Another significant assumption is 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, 2011:

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 201	$ 201	$	$ 201	$
Other commodity-based derivatives	(311)	(305)	6	(317)	(6)
Total	$ (110)	$ (104)	$ 6	$ (116)	$ (6)

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 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, 2011:

		Change in Credit Risk			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 201	$ 199	$ (2)	$ 203	$ 2
Other commodity-based derivatives	(311)	(307)	4	(314)	(3)
Total	$ (110)	$ (108)	$ 2	$ (111)	$ (1)

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 existence of taxable income in prior carryback years, the reversal of existing temporary differences, tax planning strategies and future taxable income for each of our taxable jurisdictions, the latter of which involves 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 may be required to estimate the fair value of the asset. This estimate 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. Our assessment of fair value including, but not limited to estimates of project level cash flows, requires significant judgment to make projections and assumptions that we believe a market participant would use for pricing, demand, competition, operating costs, legal and regulatory issues and other factors that extend many years into the future and 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 years ended December 31, 2011, 2010 and 2009 we recorded impairments of $7 million, $10 million and $30 million related to our long-lived assets and other assets. During 2011, in connection with the deconsolidation of Ruby we also recorded a non-cash loss of approximately $475 million based on the difference between the net carrying value in Ruby and the estimated fair value of our investment in Ruby and recorded a non-cash loss of $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt. For a further discussion of our Ruby pipeline project, see Item 8. Financial Statements and Supplementary Data, Note 18. Future changes in the economic and business environment can impact our assessments of potential impairments.

Principles of Consolidation. For entities where both we and third parties have equity or other interests, we perform an evaluation to determine which party should consolidate the entity. As part of this evaluation, we are required to determine whether or not the entity is considered a variable interest entity (VIE) and ultimately which party is considered the primary beneficiary and/or who controls the entity s operating and financial decisions. As part of these evaluations, there is a significant amount of judgment involved in evaluating the entities contractual relationships, the relative nature of the third party s and our interests in the entities, and the ability to control or direct its activities. If different judgment were applied, our accounting treatment and financial statement presentation for these entities could be significantly impacted. For a further discussion of our significant investments in unconsolidated affiliates as of December 31, 2011, see Item 8. Financial Statements and Supplementary Data, Note 18.

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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 oil and natural gas prices impact the amounts at which we sell our oil and natural gas in our Exploration and Production segment and affect the fair value of our oil and natural gas derivative contracts held in our Exploration and Production and Marketing segments; and
  - Changes in locational price differences also affect amounts at which we sell our oil and natural gas production, the fair values of any related derivative products and affect our ability to optimize pipeline transportation capacity 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 7.

Commodity Price Risk

Production-Related Derivatives

In our Exploration and Production segment we attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of derivative oil and natural gas swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives change. Our production-related derivatives do not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risks on our remaining forecasted production.

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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, 2011	$ 201	$ 88	$ (113)	$ 303	$ 102
December 31, 2010	$ 237	$ 33	$ (204)	$ 434	$ 197
Other commodity-based derivatives net assets (liabilities)					
December 31, 2011	$ (311)	$ (309)	$ 2	$ (312)	$ (1)
December 31, 2010	$ (423)	$ (422)	$ 1	$ (426)	$ (3)

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 primarily based on quoted market prices for the same or similar issues.

	December 31, 2011								December 31, 2010	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2012	2013	2014	2015	2016	Thereafter	Total	Value	Amounts	Value
						(In millions)				
Fixed rate long-term debt and other obligations(1)	$ 310	$ 123	$ 283	$ 755	$ 377	$ 9,381	$ 11,229	$ 12,659	$ 11,886	$ 12,583
Average interest rate	5.6%	8.9%	8.0%	5.5%	9.1%	7.2%				
Variable rate long-term debt and other obligations(1)	$ 52	$ 18	$ 118	$ 125	$ 1,425	$	$ 1,738	$ 1,583	$ 2,120	$ 2,103
Average interest rate	4.5%	5.3%	3.8%	5.3%	3.2%	%				

(1) Includes current portion.

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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, 2011. 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, 2011. The effectiveness of our internal control over financial reporting as of December 31, 2011 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 (the Company) as of December 31, 2011 and 2010, 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, 2011. 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 percent interest), have been audited by other auditors whose report has 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, is based solely on the report of the other auditors. In the consolidated financial statements, the Company s investments in unconsolidated affiliates includes approximately $959 million and $866 million from Citrus Corp. and Subsidiaries as of December 31, 2011 and 2010, respectively, and the Company s earnings from unconsolidated affiliates includes approximately $93 million, $90 million and $65 million for the years ended December 31, 2011, 2010 and 2009, respectively, from Citrus Corp. and Subsidiaries.

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 report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 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 changed its reserves estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 27, 2012

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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, 2011, 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, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2011 consolidated financial statements of El Paso Corporation and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 27, 2012

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per common share amounts)

	Year Ended December 31, 2011	2010	2009
Operating revenues			
Pipelines	$ 3,054	$ 2,820	$ 2,767
Exploration and Production	1,867	1,789	1,828
Marketing	(55)	(49)	29
Other	(6)	56	7
	4,860	4,616	4,631
Operating expenses			
Cost of products and services	181	218	207
Operation and maintenance	1,394	1,235	1,235
Loss on deconsolidation of subsidiary (Note 18)	600		
Ceiling test charges	152	25	2,123
Loss (gain) on long-lived assets	2	(83)	22
Depreciation, depletion and amortization	1,116	942	867
Taxes, other than income taxes	283	236	228
	3,728	2,573	4,682
Operating income (loss)	1,132	2,043	(51)
Earnings from unconsolidated affiliates	151	188	67
Loss on debt extinguishment	(169)	(217)	
Other income	226	333	144
Other expenses	(15)	(6)	(25)
Interest and debt expense	(948)	(1,031)	(1,008)
Income (loss) before income taxes	377	1,310	(873)
Income tax (benefit) expense	(50)	386	(399)
Net income (loss)	427	924	(474)
Net income attributable to noncontrolling interests	(286)	(166)	(65)
Net income (loss) attributable to El Paso Corporation	141	758	(539)
Preferred stock dividends of El Paso Corporation		(37)	(37)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 141	$ 721	$ (576)
Basic earnings (loss) per common share			
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.19	$ 1.03	$ (0.83)
Diluted earnings (loss) per common share			
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.18	$ 1.00	$ (0.83)

See accompanying notes.

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EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Year Ended December 31,		
	2011	**2010**	**2009**
Net income (loss)	$ 427	$ 924	$ (474)
Pension and postretirement obligations:			
Unrealized actuarial (losses) gains and prior service cost arising during the period (net of income taxes of $67 in 2011, $24 in 2010 and $11 in 2009)	(131)	(46)	36
Reclassifications of net actuarial losses during period (net of income taxes of $30 in 2011, $25 in 2010 and $16 in 2009)	62	46	27
Cash flow hedging activities:			
Unrealized mark-to-market (losses) gains arising during period (net of income taxes of $39 in 2011, $24 in 2010 and $6 in 2009)	(69)	(40)	11
Recognition of loss associated with interest rate swaps upon deconsolidation of subsidiary (net of income taxes of $46 in 2011)	79		
Reclassification adjustments for amounts recognized during the period (net of income taxes of $9 in 2011, $4 in 2010 and $146 in 2009)	17	7	(260)
Other comprehensive loss	(42)	(33)	(186)
Comprehensive income (loss)	385	891	(660)
Comprehensive income attributable to noncontrolling interests	(289)	(166)	(65)
Comprehensive income (loss) attributable to El Paso Corporation	$ 96	$ 725	$ (725)

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions, except share and per share amounts)

	December 31, 2011	2010
ASSETS		
Current assets		
Cash and cash equivalents (includes $31 in 2010 held by variable interest entities)	$ 194	$ 347
Accounts receivable		
Customer, net of allowance of $2 in 2011 and $4 in 2010	331	333
Affiliates	36	7
Other	192	160
Notes receivable from affiliates	85	
Materials and supplies	175	169
Assets from price risk management activities	282	265
Deferred income taxes	127	165
Other	155	106
Total current assets	1,577	1,552
Property, plant and equipment, at cost		
Pipelines (includes $3,232 in 2010 held by variable interest entities)	19,931	22,385
Oil and natural gas properties, at full cost	22,070	21,692
Other	529	416
	42,530	44,493
Less accumulated depreciation, depletion and amortization	23,360	23,421
Total property, plant and equipment, net	19,170	21,072
Other long-term assets		
Investments in unconsolidated affiliates	2,739	1,673
Assets from price risk management activities	20	61
Other	808	912
	3,567	2,646
Total assets	$ 24,314	$ 25,270

See accompanying notes.

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EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions, except share and per share amounts)

	December 31, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 415	$ 610
Affiliates	12	9
Other	409	386
Short-term financing obligations, including current maturities	362	489
Liabilities from price risk management activities	140	176
Asset retirement obligations	39	63
Accrued interest	184	202
Other	587	630
Total current liabilities	2,148	2,565
Long-term financing obligations, less current maturities	12,605	13,517
Other long-term liabilities		
Liabilities from price risk management activities	284	397
Deferred income taxes	612	568
Other	1,530	1,461
	2,426	2,426
Commitments and contingencies (Note 12)		
Preferred stock of subsidiaries		698
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
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 787,316,201 shares in 2011 and 719,743,724 shares in 2010	2,362	2,159
Additional paid-in capital	5,364	4,484
Accumulated deficit	(2,293)	(2,434)
Accumulated other comprehensive loss	(796)	(751)
Treasury stock (at cost); 15,081,177 shares in 2011 and 15,492,605 shares in 2010	(283)	(291)
Total El Paso Corporation stockholders equity	4,354	3,917
Noncontrolling interests	2,781	2,147
Total equity	7,135	6,064
Total liabilities and equity	$ 24,314	$ 25,270

See accompanying notes.

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EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Year Ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income (loss)	$ 427	$ 924	$ (474)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation, depletion and amortization	1,116	942	867
Ceiling test charges	152	25	2,123
Loss on deconsolidation of subsidiary (Note 18)	600		
Deferred income tax (benefit) expense	(23)	374	(427)
(Earnings) losses from unconsolidated affiliates, adjusted for cash distributions	(90)	(124)	21
Loss (gain) on long-lived assets	2	(83)	22
Loss on debt extinguishment	169	217	
Other non-cash income items	(87)	(129)	35
Asset and liability changes			
Accounts and notes receivable	(59)	132	142
Change in deferred purchase price from accounts receivable sales	(41)	(89)	
Change in price risk management activities, net	(65)	(181)	(46)
Accounts payable	16	(70)	(48)
Change in margin and other deposits	(6)	(35)	22
Other asset changes	(1)	(27)	(74)
Other liability changes	(9)	(123)	44
Net cash provided by operating activities	2,101	1,753	2,207
Cash flows from investing activities			
Capital expenditures and contributions to equity investments	(3,769)	(3,981)	(2,902)
Cash paid for acquisitions	(2)	(51)	(130)
Net proceeds from the sale of assets and investments	667	463	351
Increase in notes receivable from affiliates	(121)	(29)	(33)
Other	(73)	37	41
Net cash used in investing activities	(3,298)	(3,561)	(2,673)
Cash flows from financing activities			
Net proceeds from issuance of debt and other financing obligations	5,942	3,360	1,618
Payments to retire long-term debt and other financing obligations	(5,692)	(3,127)	(1,668)
Net proceeds from issuance of noncontrolling interests (Note 14)	948	1,340	212
Net proceeds from the issuance of preferred stock of subsidiary	30	120	145
Dividends paid	(38)	(65)	(177)
Distributions to noncontrolling interest holders	(200)	(96)	(48)
Distributions to holders of preferred stock of subsidiary	(15)	(21)	
Proceeds from stock option exercises	68	8	1
Other	1	1	(6)
Net cash provided by financing activities	1,044	1,520	77
Change in cash and cash equivalents	(153)	(288)	(389)
Cash and cash equivalents			

Beginning of period	347	635	1,024
End of period	$ 194	$ 347	$ 635
Supplemental cash flow information			
Interest paid, net of amounts capitalized	$ 891	$ 956	$ 968
Income tax payments (refunds)	15	(17)	(24)

See accompanying notes.

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EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF EQUITY

(In millions, except per share amounts)

	Year Ended December 31,					
	2011		2010		2009	
	Shares	Amount	Shares	Amount	Shares	Amount
El Paso Corporation stockholders equity:						
Preferred stock, $0.01 par value:						
Balance at beginning of year	1	$ 750	1	$ 750	1	$ 750
Conversion of preferred stock	(1)	(750)				
Balance at end of year			1	750	1	750
Common stock, $3.00 par value:						
Balance at beginning of year	720	2,159	716	2,148	712	2,138
Conversion of preferred stock	58	174				
Other, net	9	29	4	11	4	10
Balance at end of year	787	2,362	720	2,159	716	2,148
Additional paid-in capital:						
Balance at beginning of year		4,484		4,501		4,612
Conversion of preferred stock		576				
Dividends		(30)		(65)		(149)
Issuances of noncontrolling interests (Note 14)		213				
Stock-based compensation and other		121		48		38
Balance at end of year		5,364		4,484		4,501
Accumulated deficit:						
Balance at beginning of year		(2,434)		(3,192)		(2,653)
Net income (loss) attributable to El Paso Corporation		141		758		(539)
Balance at end of year		(2,293)		(2,434)		(3,192)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(751)		(718)		(532)
Other comprehensive income (loss) attributable to El Paso Corporation		(45)		(33)		(186)
Balance at end of year		(796)		(751)		(718)
Treasury stock, at cost:						
Balance at beginning of year	(15)	(291)	(15)	(283)	(14)	(280)
Stock-based and other compensation		8		(8)	(1)	(3)
Balance at end of year	(15)	(283)	(15)	(291)	(15)	(283)
Total El Paso Corporation stockholders equity at end of year		4,354		3,917		3,206
Noncontrolling interests:						

Balance at beginning of year	2,147	785	561
Issuance of noncontrolling interests (Note 14)	610	1,340	212
Distributions to noncontrolling interests	(200)	(96)	(48)
Net income attributable to noncontrolling interests (Note 14)	221	118	60
Other comprehensive income attributable to noncontrolling interests	3		
Balance at end of year	2,781	2,147	785
Total equity at end of year	$ 7,135	$ 6,064	$ 3,991

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements 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. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation, none of which impacted our reported net income (loss) or stockholders equity.

Proposed Merger with Kinder Morgan, Inc.

On October 16, 2011, we announced a definitive merger agreement with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that valued El Paso at approximately $38 billion (based on the KMI stock price at that date), including the assumption of debt. The merger agreement has been approved by each of our and KMI s board of directors. The completion of the merger is subject to satisfaction or waiver of certain closing conditions including, among others, customary regulatory approvals, approval by our stockholders and approval of the issuance of KMI stock and warrants by KMI s stockholders. A voting agreement has been executed by certain stockholders of KMI, holding approximately 75 percent of the voting power of KMI, in which such stockholders have agreed to vote in favor of the merger and issuance of KMI stock and warrants. The completion of the merger will constitute a change of control for El Paso that may trigger provisions in certain agreements including those related to (i) debt and other financing agreements, (ii) severance agreements and (iii) incentive compensation plan agreements that will result in an immediate acceleration of all unvested stock based compensation awards upon closing of the merger. For our debt and other financing agreements containing covenants related to change in control events and that will not be terminated pursuant to the merger, we have either amended the agreements or obtained waivers of those covenants. However, if there was a downgrade of our credit ratings upon completion of the merger with KMI, it could trigger certain other change of control provisions to certain agreements to which we are a party.

Upon the merger, El Paso shareholders will receive a combination of Class P shares of common stock of KMI, common stock purchase warrants of KMI and cash. Each share of El Paso common stock (excluding any shares held by KMI or its subsidiaries or by El Paso and dissenting shares in accordance with Delaware law), will, at the effective time of the merger, be converted into the right to receive, at the election of the holder but subject to pro-ration with respect to the stock and cash portion such that approximately 57 percent of the aggregate merger consideration (excluding the warrants) is paid in cash and approximately 43 percent (excluding the warrants) is paid in Class P common stock of KMI, par value $0.01 per share (the KMI Class P Common Stock): (i) 0.9635 of a share of KMI Class P Common Stock and 0.640 of a common stock purchase warrant of KMI (a KMI Warrant), (ii) $25.91 in cash without interest and 0.640 of a KMI Warrant or (iii) 0.4187 of a share of KMI Class P Common Stock, $14.65 in cash without interest and 0.640 of a KMI Warrant. Each KMI Warrant will entitle its holder to purchase one share of KMI Class P Common Stock at an exercise price of $40.00 per share, subject to certain adjustments, at any time during the five-year period following the closing of the merger.

The merger agreement includes customary representations, warranties and covenants, and specific agreements relating to (i) the conduct of each of El Paso s and KMI s respective businesses between the date of the signing of the merger agreement and the closing of the merger transactions and (ii) the efforts of the parties to cause the merger transactions to be completed. In addition to certain other covenants, we have agreed not to encourage, solicit, initiate or facilitate any takeover proposal from a third party or enter into any agreement, arrangement or understanding requiring us to abandon, terminate or fail to consummate the merger and related transactions. The merger agreement contains certain termination rights for both El Paso and KMI and further provides that, upon termination of the merger agreement, under certain circumstances, El Paso may be required to pay KMI a termination fee equal to $650 million or, in certain other circumstances, El Paso may be required to reimburse KMI for its expenses up to $20 million and certain financing related expenses.

Under the terms of the merger agreement, we have agreed to conduct our business in the ordinary course and in all material respects in substantially the same manner as conducted prior to the date of the merger agreement, subject to certain conditions, restrictions and thresholds including, but not limited to, our ability to (i) commit to capital expenditures above our current capital budgets (ii) acquire, invest in, or dispose of any material properties, assets, or equity interests as defined in the merger agreement (iii) incur new debt, refinance, or guarantee any debt or borrowed money, (iv) enter into, terminate, or amend certain material contracts, (v) issue, grant, sell, or redeem new El Paso capital stock or stock-based compensation awards and/or pay dividends in excess of $0.01/share, among other limitations.

In conjunction with the merger, KMI announced that they intend to sell our exploration and production assets. On February 24, 2012, we entered into a purchase and sale agreement to sell all of our exploration and production assets to an affiliate of Apollo Global Management, LLC (Apollo) and certain other parties for $7.15 billion subject to certain adjustments for items such as contributions or distributions, incurrence of debt and title defects. The sale is contemplated by the merger agreement with KMI. The closing of the sale is conditioned upon the closing of the transactions contemplated by the merger agreement with KMI. Both transactions are expected to be completed in the second quarter of 2012. The purchase and sale agreement contains customary representations and warranties relating to the exploration and production assets and operations. Additionally, El Paso has entered into a performance guarantee in favor of Apollo, under which we guarantee the performance of all of our seller subsidiaries obligations under the purchase and sale agreement. Pursuant to the merger agreement with KMI, KMI is required to indemnify us from any and all cost incurred by us arising from or relating to the sale of the exploration and production assets. Upon completion of the sale, the exploration and production business will be reflected as a discontinued operation in our financial statements.

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.

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control or direct the policies, decisions or activities of an entity. We use the cost method of accounting where we are unable to exert significant influence over the entity.

Regulated Operations

Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and follow the Financial Accounting Standards Board s accounting standards for regulated operations. Under these standards, we record regulatory assets and liabilities that would not be recorded 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 may record a regulatory asset or liability include certain postretirement employee benefit plan costs, taxes related to 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. For further details of our regulatory assets and liabilities, see Note 8.

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.

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.

Property, Plant and Equipment

Pipelines and Other (Excluding Oil and Natural Gas 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 10.

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 are not recoverable in our rates under current FERC policies.

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

Oil and Natural Gas Properties. We use the full cost method to account for our oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas 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 or it is determined that the costs are impaired. On a quarterly basis, we transfer unproved property costs into the amortizable base when properties are determined to have proved reserves. If costs are determined to be impaired, the amount of any impairment is transferred to the full cost pool if an oil or natural gas reserve base exists, or is expensed if a reserve base has not yet been created. 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 less estimated future capital expenditures, discounted at 10 percent, plus the cost of unproved oil and natural gas properties not being amortized 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 Securities and Exchange Commission (SEC) s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we utilize 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 test. We are also required to hold prices constant over the life of the reserves, even though actual prices of oil and natural gas are volatile and change from period to period. 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. The present value of future net revenues used for our ceiling test calculations excludes the impact of derivatives and the estimated future cash outflows associated with asset retirement liabilities related to proved developed reserves.

When we sell or convey interests in oil and natural gas properties, we reduce our oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of oil and natural gas 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. If 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 assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows.

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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 to participants and retirees. These contributions are invested until the benefits are paid to plan participants. The net benefit cost of these plans is recorded in our income statement and is a function of many factors including benefits earned during the year by plan participants (which is a function of factors such as 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 13.

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 certain of 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.

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, storage services and LNG terminal operations. 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. 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. For contracts with step-up or step-down rate provisions, that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. Revenues from gas not used in operations are based on the volumes we are allowed to retain relative to the amounts of gas we use for operating purposes. Prior to the implementation of a fuel volume tracker on our Tennessee Gas Pipeline (TGP) system, we recognized revenue from gas not used in operations from our shippers when the FERC allowed 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 oil, natural gas, 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.

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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 (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

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

Other Contingencies. We recognize liabilities for other contingencies when we have an exposure that 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 oil and natural gas production and interest rate exposure on our long-term debt. We also hold other derivatives not intended to hedge these exposures.

Our derivatives are reflected on our balance sheet at their fair value as assets or 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 for counterparties where we have a legal right of offset.

When we enter into derivative contracts related to our price risk management activities, we may designate the derivative as either a cash flow hedge or a fair value hedge. Cash flow hedges are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the fair value of these hedges are deferred in accumulated other comprehensive income or loss to the extent they are effective and then recognized in revenues or expenses when the hedged transactions occur. Ineffectiveness related to our cash flow hedges is recognized in earnings as it occurs. Fair value hedges are entered into to protect the fair value of a recognized asset, liability or firm commitment. Changes in the fair value of these hedges are recognized in earnings as offsets to the changes in fair value of the related hedged assets, liabilities or firm commitments.

Derivatives that we have not designated as accounting 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. In our balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 7 for a further discussion of our price risk management activities.

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.

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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 and estimable. 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 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 15.

2. Acquisitions and Divestitures

Acquisitions. During 2011, 2010 and 2009, we acquired the following assets:

	2011	2010	2009
		(In millions)	
Domestic oil and natural gas properties (Exploration and Production)	$	$ 51	$ 92
Other	2		38
Total	$ 2	$ 51	$ 130

Divestitures. During 2011, 2010 and 2009, we sold a number of assets and investments receiving proceeds as follows:

	2011	2010	2009
		(In millions)	
Pipelines	$ 3	$ 306	$ 65
Exploration and Production	612	29	93
Other	52	128	193
Total	$ 667	$ 463	$ 351

During 2011, we sold non-core oil and natural gas properties located in our Central, Western and Southern divisions in several transactions. No gain or loss was recorded on these sales. Also during 2011, we completed the sale of our remaining interest in a telecommunications equity investment and recorded a $16 million gain in earnings from unconsolidated affiliates. During the year ended 2010, we (i) completed the sale of certain Mexican pipeline and compression assets for approximately $300 million and recorded a pretax gain of approximately $80 million in earnings from unconsolidated affiliates, (ii) sold a 50 percent interest in our Altamont gathering and processing assets (which are a part of our midstream joint venture) for $125 million in cash, included in Other above, recording a pretax gain on long-lived assets of approximately $110 million and (iii) sold non-core natural gas producing properties located in our Southern division for approximately $22 million without recording a gain or loss. During 2009, we also sold oil and natural gas properties, pipeline assets and related facilities, legacy international power investments and other assets.

In February 2012, we executed an agreement with our midstream joint venture to transfer our wholly owned investment in the Eagle Ford gathering systems to the joint venture for approximately $85 million in cash.

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, 2011, 2010, and 2009, we recorded the following ceiling test charges:

	2011	2010	2009
		(In millions)	
Full cost pool:			
U.S.	$	$	$ 2,031
Brazil	152		58
Egypt		25	34
Total	$ 152	$ 25	$ 2,123

During 2011, our charge was driven, in part, by the release of certain unevaluated costs into the Brazilian full cost pool primarily as a result of the denial of a necessary environmental permit and the completion of our evaluation of two exploratory wells drilled in 2009 and 2010 without any additions to proved reserves. See Note 10 for a further discussion. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. In the future, we may incur ceiling test charges in Egypt depending on the results of our activities and political unrest in that country. We continue to evaluate the commerciality of these areas.

Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. A sustained period of low domestic natural gas prices will over time result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our proved reserves, which could result in ceiling test charges on our domestic full cost pool.

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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:

	2011	2010	2009
		(In millions)	
Other Income			
Allowance for equity funds used during construction (Note 10)	$ 195	$ 246	$ 95
Recovery of escrowed funds		40	
Interest income	23	21	26
Foreign currency gains		6	14
Other	8	20	9
Total	$ 226	$ 333	$ 144
Other Expenses			
Loss on sale of Porto Velho notes receivable	$	$	$ 22
Foreign currency losses	14		
Other	1	6	3
Total	$ 15	$ 6	$ 25

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5. Income Taxes

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

	2011	2010	2009
		(In millions)	
Pretax Income (Loss)			
U.S	$ 522	$ 1,236	$ (771)
Foreign	(145)	74	(102)
	$ 377	$ 1,310	$ (873)
Components of Income Tax (Benefit) Expense			
Current			
Federal	$	$ (4)	$ (1)
State	(22)	5	24
Foreign	(5)	11	5
	(27)	12	28
Deferred			
Federal	104	385	(400)
State	(127)	(5)	(26)
Foreign		(6)	(1)
	(23)	374	(427)
Total income tax (benefit) expense	$ (50)	$ 386	$ (399)

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

	2011	2010	2009
		(In millions, except rates)	
Income taxes at the statutory federal rate of 35%	$ 132	$ 459	$ (305)
Increase (decrease)			
State income taxes, net of federal income tax effect			
Subsidiary conversion to limited liability company	(74)		
Other	(29)	2	44
Income attributable to nontaxable noncontrolling interests	(100)	(58)	(23)
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(34)	(34)	(23)
Foreign income (loss) taxed at different rates	33	4	(42)
Valuation allowances	21	6	47
Healthcare legislation Elimination of Medicare subsidy		18	
Sales and write-offs of foreign investments		(19)	(88)
Other	1	8	(9)
Income tax expense (benefit)	$ (50)	$ 386	$ (399)
Effective tax rate	(13)%	29%	46%

Our negative effective tax rate for the year ended December 31, 2011 reflects (i) the impact of a low level of pretax income, (ii) a deferred state tax benefit (before valuation allowance) recorded upon the conversion of a subsidiary to a limited liability company which reduced state effective tax rates and (iii) the favorable resolution of certain tax matters. Partially offsetting these items is a $53 million tax impact of a Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit (deferred Brazilian tax benefits offset by an equal valuation allowance).

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 international power projects, these entities had no liquidating value. As these entities had tax basis, the liquidation resulted in a tax loss.

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

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through a structured sale which would not result in any additional deferred tax liabilities. At December 31, 2011, the undistributed earnings of our unconsolidated affiliates for which we expect to receive a dividends received deduction was approximately $543 million.

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

	2011	2010
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 2,426	$ 2,132
Investments in affiliates	967	124
Regulatory and other assets	105	96
Total deferred tax liability	3,498	2,352
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	2,235	1,180
State	124	66
Foreign	208	219
Benefits and compensation	371	293
Price risk management activities	67	158
Legal and other reserves	196	164
Other	234	269
Valuation allowance	(412)	(391)
Total deferred tax asset	3,023	1,958
Net deferred tax liability	$ 475	$ 394

Deferred tax assets on net operating loss carryovers as well as deferred tax liabilities on property, plant and equipment and investments in affiliates increased from 2010 to 2011 primarily as a result of accelerated tax depreciation on 2011 capital expenditures.

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 practicable. At December 31, 2011, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $89 million.

Unrecognized Tax Benefits. 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 2001 and U.S. income tax examinations for years prior to 2007. For years in which our returns are still subject to review, our unrecognized tax benefits 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:

	2011	2010
	(In millions)	
Amount at January 1	$ 276	$ 260
Additions:		
Tax positions taken in prior years	1	19
Tax positions taken in current year	5	7
Foreign currency fluctuations		1

Reductions:		
Settlements with taxing authorities	(2)	(6)
Foreign currency fluctuations	(1)	
Statute of limitations expiration	(13)	(5)
Amount at December 31	$ 266	$ 276

As of December 31, 2011 and 2010, approximately $260 million and $275 million (net of federal tax benefits) of unrecognized tax benefits and associated interest and penalties would affect our income tax expense and our effective income tax rate if recognized in future periods. We believe it is reasonably possible that the total amount of unrecognized tax benefits (including interest and penalty) will decrease by as much as $80 million over the next 12 months as a result of the anticipated favorable resolution of certain tax matters.

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We classify interest and penalties related to unrecognized tax benefits as income taxes in our financial statements. During 2011, 2010 and 2009, we recognized in our consolidated statements of income $(15) million, $(1) million and $3 million associated with interest and penalties related to unrecognized tax benefits. As of December 31, 2011 and 2010, we had $36 million and $51 million of accrued interest and penalties on our consolidated balance sheets.

Tax Credit and Net Operating Loss Carryovers. As of December 31, 2011, we have U.S. federal alternative minimum tax credits of $290 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2011 which increased substantially from 2010 related to depreciation elections taken on capital expenditures.

	Carryover Period				
	2012	**2013-2016**	**2017-2021**	**2022-2031**	**Total**
			(In millions)		
U.S. federal net operating loss	$ 3	$	$ 806	$ 5,125	$ 5,934
State net operating loss	12	655	792	1,754	$ 3,213

We also had $510 million of foreign net operating loss carryovers and $89 million of foreign capital loss carryovers, the majority of 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 bases 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, 2011, our valuation allowance primarily relates to deferred tax assets recorded on state and foreign net operating losses and temporary differences. The valuation allowance related to our Brazilian and Egyptian net operating losses was initially established primarily as a result of changes in the worldwide economic conditions that created uncertainty in our outlook as to future taxable income in those jurisdictions. Given the nature of our current international operations, we cannot reasonably forecast future taxable income and thus continue to maintain a full valuation allowance. In 2011, we increased our valuation allowance by $18 million on deferred tax assets associated with Brazil and Egypt net operating losses and temporary differences and $3 million on deferred tax assets associated with federal and state net operating losses. 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

Basic and diluted earnings (loss) per common share was as follows for the three years ended December 31:

	2011		2010		2009	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)					
Net income (loss) attributable to El Paso Corporation	$ 141	$ 141	$ 758	$ 758	$ (539)	$ (539)
Preferred stock dividends of El Paso Corporation			(37)		(37)	(37)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 141	$ 141	$ 721	$ 758	$ (576)	$ (576)
Weighted average common shares outstanding	751	751	698	698	696	696
Effect of dilutive securities:						
Stock-based awards		12		6		
Convertible preferred stock		11		58		
Weighted average common shares outstanding and dilutive securities	751	774	698	762	696	696
Basic and diluted earnings (loss) per common share:						
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.19	$ 0.18	$ 1.03	$ 1.00	$ (0.83)	$ (0.83)

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. Potentially dilutive securities consist of stock based awards (employee stock options, restricted stock and performance shares), convertible preferred stock and trust preferred securities. In March 2011, we converted our preferred stock to common stock as further described in Note 14. For the years ended December 31, 2011 and 2010, our trust preferred securities and certain of our employee stock options were antidilutive. For the year ended December 31, 2009, we incurred losses attributable to El Paso Corporation and, accordingly, excluded all potentially dilutive securities from the determination of diluted earnings per share. For a discussion of our capital stock activity, our stock-based compensation arrangements, and other instruments noted above, see Notes 14 and 15.

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7. Financial Instruments

The following table reflects the carrying value and fair value of our financial instruments:

	As of December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 12,967	$ 14,242	$ 14,006	$ 14,686
Marketable securities in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(110)	(110)	(186)	(186)
Interest rate derivatives	(12)	(12)	(61)	(61)
Other	1	1	(11)	(11)

As of December 31, 2011 and 2010, the carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and short-term financing obligations represent fair value because of the short-term nature of these instruments. The carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on the nature of their interest rates and our assessment of the ability to recover these amounts. We estimated the fair value of our long-term financing obligations primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to those instruments.

Our derivative financial instruments are further described below:

Production-Related Commodity Based Derivatives. As of December 31, 2011 and 2010, we have production-related derivatives (oil and natural gas swaps, basis swaps and option contracts) to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas production on 14,530 MBbl and 12,240 MBbl of oil and 105 TBtu and 283 TBtu of natural gas. None of these contracts are designated as accounting hedges.

Other Commodity-Based Derivatives. As of December 31, 2011 and 2010, in our Marketing segment we have forwards, swaps and option contracts related to long-term natural gas and power. These contracts, the longest of which extends into 2019, include (i) obligations to sell natural gas to power plants ranging from 12,550 MMBtu/d to 95,000 MMBtu/d and (ii) an obligation 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 on approximately 1,700 GWh to 3,700 GWh, to provide annually approximately 1,700 GWh of power and approximately 71 GW of installed capacity in the PJM power pool. We have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts. None of these derivatives are designated as accounting hedges.

Interest Rate Derivatives. We have long-term debt with variable interest rates that exposes us to changes in market-based interest rates. As of December 31, 2011 and 2010, we had interest rate swaps that are designated as cash flow hedges that effectively convert the interest rate on approximately $0.1 billion and $1.3 billion of debt from a floating LIBOR interest rate to a fixed interest rate. The majority of the balance at December 31, 2010 related to interest rate swaps on $1.1 billion of debt related to the construction of the Ruby pipeline. These hedges began accruing interest on June 30, 2011 and have termination dates ranging from June 2013 to June 2017 which correspond to the estimated principal outstanding on the debt over the term of these swaps. In connection with the deconsolidation of Ruby Pipeline Holding Company, L.L.C. (Ruby), these interest rate swaps and the related accumulated other comprehensive loss are no longer reflected on our balance sheet. For a further discussion of Ruby, see Note 18.

We also have long-term debt with fixed interest rates that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps designated as fair value hedges to protect the value of certain of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments. We record changes in the fair value of these derivatives in interest expense which is offset by changes in the fair value of the related hedged items. As of December 31, 2011 and 2010, these interest rate swaps converted the interest rate on approximately $162 million and $184 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18 percent.

Fair Value Measurements. We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument, data available for similar instruments in similar markets or other assumptions a market participant would use related to estimates of future settlements of the instrument.

We separate the fair values of our financial instruments 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 fair value. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument and would be reflected at the end of the period in which the change occurs. 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 in non-qualified compensation plans.

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 oil and natural gas derivatives and certain of our other natural gas derivatives (such as natural gas supply arrangements) whose fair values are based on commodity and other 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 also reflect adjustments for being in less liquid markets or having longer contractual terms. Primarily included in this level are our power-related derivatives and certain of our remaining natural gas derivatives. To determine the fair value of these instruments, we obtain pricing data from third party pricing sources and develop an estimate of forward prices that we believe market participants would use based on the liquidity of the underlying forward markets over the contractual terms. 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 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).

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Financial Statement Presentation. Our marketable securities in non-qualified compensation plans and other included in the table below are reflected at fair value on our balance sheets as other long-term assets and other current liabilities. We net our derivative assets and liabilities for counterparties where we have a legal right of offset and classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. At December 31, 2011 and 2010, cash collateral held was not material. The following table presents the fair value of our financial instruments at December 31, 2011 and 2010 (in millions).

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity-based derivatives								
Production-related oil and natural gas derivatives	$	$ 304	$	$ 304	$	$ 373	$	$ 373
Other natural gas derivatives		57	12	69		139	18	157
Power-related derivatives			6	6			31	31
Total commodity-based derivative assets		361	18	379		512	49	561
Interest rate derivatives designated as hedges								
Fair value hedges		2		2		8		8
Impact of master netting arrangements		(76)	(3)	(79)		(229)	(14)	(243)
Total price risk management assets	$	$ 287	$ 15	$ 302	$	$ 291	$ 35	$ 326
Marketable securities in non-qualified compensation plans	20			20	20			20
Total net assets	$ 20	$ 287	$ 15	$ 322	$ 20	$ 291	$ 35	$ 346
Liabilities								
Commodity-based derivatives								
Production-related oil and natural gas derivatives	$	$ (103)	$	$ (103)	$	$ (136)	$	$ (136)
Other natural gas derivatives		(111)		(111)		(162)	(90)	(252)
Power-related derivatives			(275)	(275)			(359)	(359)
Total commodity-based derivative liabilities		(214)	(275)	(489)		(298)	(449)	(747)
Interest rate derivatives designated as hedges								
Cash flow hedges		(14)		(14)		(69)		(69)
Impact of master netting arrangements		76	3	79		229	14	243
Total price risk management liabilities	$	$ (152)	$ (272)	$ (424)	$	$ (138)	$ (435)	$ (573)
Other			(10)	(10)			(12)	(12)
Total net liabilities	$	$ (152)	$ (282)	$ (434)	$	$ (138)	$ (447)	$ (585)
Total	$ 20	$ 135	$ (267)	$ (112)	$ 20	$ 153	$ (412)	$ (239)

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The following table presents the changes in our financial assets and liabilities included in Level 3 for the years ended December 31, 2011 and 2010:

(In millions)	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues[1]	Change in Fair Value Reflected in Operating Expenses[2]	Settlements	Reclassifications to Level 2[3]	Balance at End of Period
December 31, 2011						
Assets	$ 35	$ (18)	$	$ (2)	$	$ 15
Liabilities	(447)	5	(7)	125	42	(282)
Total	$ (412)	$ (13)	$ (7)	$ 123	$ 42	$ (267)
December 31, 2010						
Assets	$ 58	$ (21)	$	$ (2)	$	$ 35
Liabilities	(550)	(22)	(3)	128		(447)
Total	$ (492)	$ (43)	$ (3)	$ 126	$	$ (412)

(1) Includes approximately $7 million and $41 million of net losses that had not been realized through settlements for the year ended December 31, 2011 and 2010.

(2) Includes approximately $4 million and $2 million of net losses that had not been realized through settlements for the year ended December 31, 2011 and 2010.

(3) In 2011, we reclassified certain of our natural gas derivatives from Level 3 to Level 2 because the maturities of these contracts no longer extended beyond the periods in which quoted market prices are available.

Below are the impacts of our commodity-based and interest rate derivatives to our statements of income and statements of comprehensive income for the years ended December 31, 2011 and 2010:

	2011			2010		
(In millions)	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)
Production-related derivatives	$ 284	$	$ 11	$ 390	$	$ 11
Other natural gas and power derivatives not designated as hedges	(11)			(45)		
Total interest rate derivatives [1]		23	55[2]		18	(52)
Total	$ 273	$ 23	$ 66	$ 345	$ 18	$ (41)

(1) No ineffectiveness was recognized on our interest rate hedges for the years ended December 31, 2011, 2010 and 2009.

(2) Includes $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Rubys debt in conjunction with its deconsolidation (see Note 18) included in loss on deconsolidation of subsidiary in the consolidated statements

of income.

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Credit Risk. We are subject to the risk of loss on our financial instruments that we would incur as a result of non-performance by counterparties or by their failure to post the required collateral pursuant to the terms of their contractual obligations. These exposures are offset where we have a legally enforceable right of setoff. We maintain credit policies with regard to our counterparties to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties financial condition (including credit rating), (ii) obtaining collateral under certain circumstances (including cash in advance, letters of credit, and guarantees), (iii) the use of margining provisions in standard contracts, and (iv) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. If one of these counterparties fails to perform, we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and/or quantities cannot be established.

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

The following table presents a summary of our exposure from derivative contracts, net of collateral and liabilities where a right of offset exists. It is presented by type of derivative counterparty in which we had net asset exposure as of December 31, 2011 and 2010:

Counterparty	Investment Grade[(1)]	Below Investment Grade[(1)]	Not Rated[(1)]	Total
		(In millions)		
December 31, 2011				
Financial institutions	$ 280	$	$	$ 280
Natural gas and electric utilities	2	2	14	18
Energy marketers		3		3
Net financial instrument assets	282	5	14	301
Collateral held by us[(2)]			(14)	(14)
Net exposure from derivative assets	$ 282	$ 5	$	$ 287
December 31, 2010				
Financial institutions	$ 331	$	$	$ 331
Natural gas and electric utilities			35	35
Midstream companies		6		6
Net financial instrument assets	331	6	35	372
Collateral held by us[(2)]			(23)	(23)
Net exposure from derivative assets	$ 331	$ 6	$ 12	$ 349

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

(2) Consists primarily of non-cash collateral such as letters of credit.

As of December 31, 2011, we have approximately 34 counterparties to our derivative contracts. Based on our assessment of counterparty risk in light of the collateral our counterparties have posted with us (primarily in the form of letters of credit), we have determined that our exposure is primarily related to our production-related derivatives and is limited to eight financial institutions, each of which has a current Standard & Poor s credit rating of A- or better. Additionally, as of December 31, 2011, three counterparties, Credit Suisse Energy L.L.C., Societe General and Bank of Nova Scotia comprise 22 percent, 18 percent and 15 percent, respectively, of our net financial instrument exposure. As of December 31, 2010, three counterparties, Morgan Stanley Capital Group, Citibank and J. Aron comprised 27 percent, 21 percent and 10 percent, respectively, of our net financial instrument asset exposure. The concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

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As part of our assessment of fair value of our financial liabilities, we also assess our own credit risk after considering collateral posted related to these positions. On January 1, 2009, we adopted accounting standards 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 and recorded a $34 million gain (net of $18 million of taxes), or $0.05 per share, as a result of adopting this new accounting standard update.

8. Regulatory Assets and Liabilities

Our regulatory assets and liabilities relate to our interstate pipeline operations and are included in other current and non-current assets and liabilities on our balance sheets (see Note 9). These balances are recoverable or reimbursable over various periods. Below are the details of our regulatory assets and liabilities as of December 31:

	2011	2010
	(In millions)	
Current regulatory assets		
Difference between gas retained and gas consumed in operations	$ 21	$ 26
Other	18	10
Total current regulatory assets	39	36
Non-current regulatory assets		
Taxes on capitalized funds used during construction	190	254
Postretirement benefits	8	9
Unamortized net loss on reacquired debt	54	63
Unamortized loss on assets held for sale	32	
Other	19	23
Total non-current regulatory assets	303	349
Total regulatory assets	$ 342	$ 385
Current regulatory liabilities		
Difference between gas retained and gas consumed in operations	$ 22	$ 13
Environmental liability	40	78
Other	9	5
Total current regulatory liabilities	71	96
Non-current regulatory liabilities		
Environmental liability	6	44
Property and plant depreciation	37	45
Postretirement benefits	26	71
Other	13	17
Total non-current regulatory liabilities	82	177
Total regulatory liabilities	$ 153	$ 273

The significant regulatory assets and liabilities include:

Difference between gas retained and gas consumed in operations. These amounts reflect the value of the volumetric difference between the gas retained and consumed in our operations. These amounts are not included in the rate base but, given our tariffs, are expected to be recovered from our customers or returned to our customers in subsequent fuel filing periods.

Taxes on capitalized funds used during construction. Represents the regulatory asset balance established to offset the deferred tax for the equity component of the allowance for funds used during the construction (AFUDC) of long-lived assets. Taxes on capitalized funds used during construction and the offsetting deferred income taxes are included in the rate base and are recovered over the depreciable lives of the long lived asset to which they relate. As a result of the deconsolidation of our investment in Ruby in September 2011, we no longer include the amounts related to the Ruby pipeline on our balance sheet at December 31, 2011. For a further discussion of the deconsolidation of Ruby, see Note 18.

Postretirement benefits. Represents unrecognized gains and losses or changes in actuarial assumptions related to our postretirement benefit plans and differences in the postretirement benefit related amounts expensed and the amounts recovered in rates. Postretirement benefit amounts have been included in the rate base computations for certain of our pipelines and are recoverable in such periods as benefits are funded. During 2011, as part of our rate case settlements on certain of our pipelines, we were required to reduce a portion of these balances. As such, we reclassified $19 million, net of taxes of $6 million, to accumulated other comprehensive income and recorded an increase of approximately $29 million in operating revenues.

Unamortized net loss on reacquired debt. Amount represents the deferred and unamortized portion of losses on reacquired debt which are recovered over the original life of the debt issuance through the cost of service.

Unamortized loss on assets held for sale. In September 2011, we entered into an agreement to sell certain Southern Natural Gas (SNG) offshore and onshore assets located in the Gulf of Mexico and Louisiana. We recorded the deferred and unamortized portion of losses on those assets held for sale in non-current regulatory assets. The recovery of this amount is expected to occur at a fixed monthly rate until SNG s next rate case, which is expected to be effective September 2013 and the final recovery period will be dependent upon the outcome of that rate case.

Environmental liability. Includes amounts collected, substantially in excess of certain polychlorinated biphenyl (PCB) environmental remediation costs to date, through a surcharge to TGP s customers under a settlement approved by the FERC in November of 1995. This environmental liability is not deducted from the rate base on which TGP is allowed to earn a return. For a further discussion of this matter, see Note 12.

Property and plant depreciation. Amounts represent the deferral of customer-funded amounts for costs of future asset retirements.

9. Other Assets and Liabilities

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

	2011	2010
	(In millions)	
Other current assets		
Prepaid expenses	$ 54	$ 54
Regulatory assets (Note 8)	39	36
Assets held for sale	50	
Other	12	16
Total	$ 155	$ 106
Other non-current assets		
Regulatory assets (Note 8)	$ 303	$ 349
Unamortized debt expenses	108	161
Pension and other postretirement benefits (Note 13)	111	106
Notes receivable from affiliates	86	101
Long-term receivables	84	89
Other	116	106
Total	$ 808	$ 912

	2011	2010
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 114	$ 144
Environmental, legal and rate reserves (Note 12)	196	106
Regulatory liabilities (Note 8)	71	96
Pension and other postretirement benefits (Note 13)	35	44
Income taxes (Note 5)	8	30
Deposits	40	37

Other	123	173
Total	$ 587	$ 630
Other non-current liabilities		
Pension and other postretirement benefits (Note 13)	$ 815	$ 626
Regulatory liabilities (Note 8)	82	177
Environmental and legal reserves (Note 12)	133	133
Asset retirement obligations (Note 10)	164	125
Insurance reserves	68	68
Other	268	332
Total	$ 1,530	$ 1,461

10. Property, Plant and Equipment

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

	Method	Depreciable Lives (In years)
Regulated transmission systems	Composite	(1)
Non-regulated assets		
Oil and natural gas properties	Unit of Production	(2)
Transmission and storage facilities	Straight-line	15-40
Gathering and processing systems	Straight-line	10-22
Transportation equipment	Straight-line	5-15
Buildings and improvements	Straight-line	10-40
Office and miscellaneous equipment	Straight-line	3-20

(1) Under the composite (group) method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our rate settlements to the total cost of the group until its net book value equals its salvage value. We re-evaluate depreciation rates each time we file with the FERC for an increase or decrease in our rates.

(2) Capitalized costs associated with proved reserves are amortized over the life of the reserves. Capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, or it is determined that the costs are impaired.

Excess purchase costs. As of December 31, 2011 and 2010, TGP and El Paso Natural Gas Pipeline (EPNG) have excess purchase costs associated with their historical acquisition. Total excess costs on these pipelines were approximately $2.5 billion and accumulated depreciation was approximately $0.6 billion and $0.5 billion at December 31, 2011 and 2010. These excess purchase costs are being depreciated over an estimated weighted average remaining life of 47 years and our related depreciation expense for each year ended December 31, 2011, 2010, and 2009 was approximately $42 million.

Capitalized costs during construction. We capitalize a pre-tax carrying cost on funds related to the construction of long-lived assets and reflect this amount as an increase in the cost of the asset on our balance sheet. We also capitalize amounts that consist of (i) an interest cost on our debt that could be attributed to the assets being constructed, and (ii) for our regulated pipelines, a return on our equity that could be attributed to the assets being constructed. The equity portion is calculated using the most recent FERC approved equity rate of return. Interest costs capitalized are included as a reduction of interest expense in our income statements and were $63 million, $60 million and $48 million during the years ended December 31, 2011, 2010 and 2009. Equity amounts capitalized (exclusive of taxes) in our FERC regulated business are included as other non-operating income on our income statement and were $124 million, $156 million and $61 million during the years ended December 31, 2011, 2010 and 2009. These amounts are recovered over the depreciable lives of the long-lived assets to which they relate and are non-cash investing activities.

Construction work-in-progress. At December 31, 2011 and 2010, we had approximately $1.3 billion and $4.8 billion of construction work-in-progress included in our property, plant and equipment.

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Unevaluated Capitalized Costs. Unevaluated capitalized costs of oil and natural gas properties were as follows:

	December 31, 2011	December 31, 2010
	(In millions)	
U.S.		
Acquisition	$ 301	$ 407
Exploration	98	130
Total U.S	399	537
Egypt & Brazil		
Acquisition	36	45
Exploration	46	203
Total Egypt & Brazil	82	248
Worldwide	$ 481	$ 785

During 2011, we released approximately $86 million of our unevaluated capitalized costs to our Brazilian full cost pool upon completing our evaluation of certain exploratory wells drilled in 2009 and 2010 and also released approximately $94 million related to a Brazilian development project where we were denied a necessary environmental permit. These actions contributed to a ceiling test charge recorded on the Brazilian full cost pool during 2011. See Note 3 for a further discussion. At December 31, 2011, we have total oil and natural gas capitalized costs of approximately $74 million and $205 million in Egypt and Brazil, of which $74 million and $8 million are unevaluated capitalized costs.

Asset retirement obligations. We have legal obligations associated with the retirement of our oil and natural gas wells and related infrastructure, natural gas pipelines, transmission facilities and storage wells. In our exploration and production operations, we have obligations to plug wells when abandoned because production is exhausted or we no longer plan to use the wells. In our pipeline operations, our legal obligations primarily involve purging and sealing the pipelines if they are abandoned. We also have obligations to remove hazardous materials associated with our natural gas transmission facilities if they are ever demolished or replaced. We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record.

Where we can reasonably estimate the asset retirement obligation, we accrue a liability based on an estimate of the timing and amount of settlement. In estimating our asset retirement obligations, we utilize several assumptions, including a projected inflation rate of 2.5 percent, and credit-adjusted discount rates that currently range from 5 to 12 percent based on when the liabilities were recorded. We record changes in these estimates based on changes in the expected amount and timing of payments to settle our obligations. Typically, these changes result from obtaining new information about the timing of our obligations to plug and abandon our oil and natural gas wells and the costs to do so and from certain other events that accelerate the timing of asset retirements (e.g. the impact of hurricanes). In our pipelines operations, we intend on operating and maintaining our natural gas pipeline and storage systems as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the asset retirement obligation for the substantial majority of our natural gas pipeline and storage system assets because these assets have indeterminate lives.

The net asset retirement obligation as of December 31 reported on our balance sheet in other current and non-current liabilities and the changes in the net liability for the years ended December 31 were as follows:

	2011	2010
	(In millions)	
Net asset retirement obligation at January 1	$ 188	$ 291
Liabilities settled	(19)	(84)
Accretion expense	14	20
Liabilities incurred	3	11

Changes in estimate[1]	17	(50)
Net asset retirement obligation at December 31	$ 203	$ 188

(1) Amount for 2010 reflects updated information received on our hurricane related asset retirement obligations.

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11. Debt, Other Financing Obligations and Other Credit Facilities

	Year Ended December 31, 2011	2010
	(In millions)	
Short-term financing obligations, including current maturities	$ 362	$ 489
Long-term financing obligations	12,605	13,517
Total	$ 12,967	$ 14,006

The following provides additional detail on our financing obligations:

	Year Ended December 31, 2011	2010
	(In millions)	
Colorado Interstate Gas (CIG)		
Notes, 5.95% through 6.85%, due 2015 through 2037	$ 475	$ 475
El Paso Corporation		
Notes, 6.50% through 12.00%, due 2012 through 2037	4,148	5,469
Revolving credit facilities, variable due 2014 through 2016	673	225
EPNG		
Notes, 5.95% through 8.625%, due 2017 through 2032	1,115	1,115
EP Energy Corporation (EPE)		
Note, 7.75%, due 2013	1	1
Revolving credit facility, variable due 2016	850	300
El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC)		
Revolving credit facility, variable due 2016		270
Notes, 4.10% through 8.00%, due 2012 through 2040	1,888	1,425
Notes, variable due 2012	35	35
SNG		
Notes, 4.40% through 8.00%, due 2017 through 2032	1,211	911
TGP		
Notes, 7.00% through 8.375%, due 2016 through 2037	1,790	1,876
Other	183	222
	12,369	12,324
Other financing obligations		
Capital Trust I, due 2028	325	325
Ruby Pipeline, L.L.C. credit facility		1,094
Other	318	320
	13,012	14,063
Less:		
Other, including unamortized discounts and premiums	45	57
	12,967	14,006
Current maturities	362	489
Total long-term financing obligations, less current maturities	$ 12,605	$ 13,517

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Changes in Financing Obligations. During 2011, we had the following changes in our long-term financing obligations (in millions):

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Ruby Pipeline, L.L.C. credit facility	variable	393	393
SNG notes due 2021	4.40%	300	297
EPE revolving credit facility	variable	2,030	2,023
El Paso revolving credit facilities	variable	1,764	1,755
EPPOC revolving credit facility	variable	990	983
EPPOC notes due 2021	5.00%	497	491
Increases through December 31, 2011		$ 5,974	$ 5,942
Repayments, repurchases, and other			
EPE revolving credit facility	variable	$ (1,480)	$ (1,480)
El Paso revolving credit facility	variable	(1,316)	(1,316)
EPPOC revolving credit facility	variable	(1,260)	(1,260)
EPPOC notes due 2011	7.76%	(37)	(37)
TGP notes due 2011	6.00%	(86)	(86)
El Paso notes due 2011	7.00%-7.625%	(332)	(332)
El Paso notes due 2012 through 2037	6.875%-12.00%	(999)	(1,159)
Ruby Pipeline L.L.C. credit facility[1]	variable	(1,487)	
Other	various	(16)	(22)
Decreases through December 31, 2011		$ (7,013)	$ (5,692)

(1) In September 2011, the Ruby debt obligations became non-recourse to us and we deconsolidated Ruby. As a result, we no longer reflect the debt obligations or related interest rate swaps on our balance sheet (see Note 18).

Loss on Debt Extinguishment. In 2011, we repurchased approximately $1.0 billion of our senior unsecured notes. In conjunction with these transactions, we recorded total losses on debt extinguishment of $169 million.

In 2010, we repurchased approximately $709 million of our senior notes and exchanged approximately $349 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020. In conjunction with these transactions, we paid $168 million of cash premiums and recorded losses on debt extinguishment of $217 million.

Debt Maturities. Aggregate maturities of the principal amounts of long-term financing obligations as of December 31, 2011 for the next 5 years and in total thereafter are as follows (in millions):

2012	$ 362
2013	142
2014	401
2015	881
2016	1,811
Thereafter	9,415
Total long-term financing obligations, including current maturities	$ 13,012

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Credit Facilities/Letters of Credit

We have various credit facilities in place which allow us to borrow funds or issue letters of credit (LCs). We enter into letters of credit and issue surety bonds in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of December 31, 2011, the aggregate amount of borrowings outstanding under all of our credit facilities was $1.5 billion. In addition, we had $0.6 billion of letters of credit and surety bonds outstanding at December 31, 2011, including approximately $0.3 billion related to our price risk management activities. Listed below is a further description of our credit facilities including remaining capacity under the facilities as of December 31, 2011:

Credit Facility/ Agreement	Maturity Date	Interest Rate	Commitment/ Facility Fees	Remaining Capacity as of December 31, 2011
$1.25 Billion Revolver	May 2016	LIBOR + 2.25% 2.25% for LCs[(1)]	0.45% commitment fee on unused capacity[(1)]	$0.6 billion
$625 Million Unsecured Facilities[(2)]	April 2012 September 2014	[(2)]	5.15% (weighted average) facility fee	$0.07 billion
EPE $1.0 Billion Revolver	June 2016	LIBOR + 2.25%[(3)]	0.50% commitment fee on unused capacity[(3)]	$0.2 billion
EPPOC $1.0 Billion Unsecured Revolver[(4)]	May 2016	LIBOR + 2.00%[(5)]	0.40% commitment fee[(5)]	$1.0 billion

(1) Based on our December 31, 2011 credit rating. The applicable margin used to calculate interest on borrowings, letters of credit and commitment fees is determined by a variable pricing grid tied to the credit ratings of our senior secured debt.
(2) This multi-issuer facility is primarily used for letters of credit; however, this facility allows for cash draws of up to $150 million from one of the parties to the facility. As of December 31, 2011, we borrowed $98 million at an interest rate of LIBOR + 1.5%.
(3) Based on December 31, 2011 borrowing levels.
(4) This facility is only available to EPPOC and its subsidiaries, any borrowings are guaranteed by El Paso Pipeline Partners, L.P. (EPB) and its designated subsidiaries. Amounts borrowed are non-recourse to El Paso. Borrowing capacity is expandable to $1.5 billion for certain expansion projects and acquisitions.
(5) Based on EPPOC s December 31, 2011 credit rating. The applicable margin used to calculate interest on borrowings, letters of credit and commitment fees is determined by a variable pricing grid tied to the credit ratings of EPPOC s senior unsecured debt.

Restrictive Covenants and Collateral Provisions

$1.25 Billion Revolving Credit Agreement. El Paso and certain of its subsidiaries have guaranteed this facility, which is collateralized by our general partnership interests in EPB and by our stock ownership in EPNG and TGP who are also eligible borrowers. During 2011 our collateral restrictions were modified providing us the ability to sell up to 100 percent of our ownership interests in either EPNG or TGP, or a combination thereof, to EPB. Upon achieving investment grade status (with stable outlook) by either of the two rating agencies, Standard & Poors and Moody s, collateral support on this facility will be eliminated. Our covenants under the $1.25 billion revolving credit facility include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers (e.g. our proposed merger with KMI) and on the sales of assets, dividend restrictions, cross default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries upon such event unless our agreement is amended or these covenants are waived. Under our credit agreement, the most restrictive debt covenants and cross default provisions are:

(a) Our ratio of Debt to Consolidated earnings before interest, income taxes, depreciation and amortization (EBITDA), each as defined in the credit agreement, shall not exceed 5.25 to 1 until maturity;

(b) Our ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense plus dividends paid shall not be less than 2.0 to 1 until maturity;

(c) EPNG and TGP cannot incur incremental debt if the incurrence of this incremental debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the credit agreement, for that particular company to exceed 5.0 to 1; and

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

EPE $1.0 Billion Revolving Credit Agreement. This facility is collateralized by certain of our oil and natural gas properties. The credit agreement is subject to a borrowing base redetermination on a semi-annual basis. In November 2011, the latest revaluation, our borrowing base capacity was re-affirmed at $1.0 billion by the lenders in the facility. EPE s borrowings under this facility are also subject to other conditions. The financial coverage ratio under the facility requires that EPE s debt to EBITDA, as defined in the credit agreement, must not exceed 4.0 to 1.0 and that EPE s EBITDA to interest expense not be less than 2.0 to 1.0.

EPPOC $1.0 Billion Revolving Credit Facility. This facility requires that EPB and Wyoming Interstate (WIC) maintain a consolidated leverage ratio (consolidated indebtedness to consolidated EBITDA) as defined in the credit agreement as of the end of each quarter of less than 5.0 to 1.0 for any trailing four consecutive quarter period; and 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified permitted acquisitions. Borrowings under this facility are restricted for use by EPPOC and its subsidiaries.

Other Restrictions and Provisions. In addition to the above restrictions and provisions, we and/or our subsidiaries are subject to various financial and non-financial covenants and restrictions. These covenants and restrictions include change in control provisions; limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the incurrence of liens; limitations on some of our subsidiaries to participate in our cash management program and potential limitations on the ability of some of our subsidiaries to declare and pay dividends. Our most restrictive cross-acceleration provision is associated with the indenture of one of our subsidiaries. This indenture states that should an event of default occur resulting in the acceleration of other debt obligations of that subsidiary in excess of $10 million, the long-term debt obligation containing that provision could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition. As of December 31, 2011, we were in compliance with the debt covenants and restrictions in each of the credit agreements and facilities noted above.

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

Other Financing Arrangements

Capital Trusts. El Paso Energy Capital Trust I (Trust I), is a wholly owned business trust that issued 6.5 million of 4.75 percent trust convertible preferred securities for $325 million. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued, which are due 2028. Trust I s sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of Trust I s preferred securities.

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

WYCO Development L.L.C. (WYCO). In conjunction with the construction of the Totem Gas Storage facility (Totem) and the High Plains pipeline, our joint venture partner in WYCO funded 50 percent of the construction costs. We reflected these payments made by our joint venture partner as other non-current liabilities on our balance sheet during construction and upon project completion these advances were converted into a financing obligation to WYCO. As of December 31, 2011, the principal amounts of the Totem facility and the High Plains pipeline facility were $77 million and $100 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. Interest payments on these obligations are based on 50 percent of the operating results of the facilities and are currently estimated at a 15.5 percent rate as of December 31, 2011.

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12. Commitments and Contingencies

Legal Proceedings

Shareholder Class Actions. Beginning on October 17, 2011, twenty-one purported shareholder class actions were filed challenging the proposed acquisition of El Paso by KMI. The lawsuits were filed against both companies, an advisor and the El Paso board of directors. The shareholder class actions generally allege that the El Paso board breached its fiduciary duties to the shareholders by approving the transaction and that the two companies aided in the alleged breach. All of the shareholder class actions seek to enjoin the transaction and a hearing was held in Delaware Chancery Court in February 2012. We anticipate that a decision regarding the injunction will be made by the court by early March 2012. Eight of the actions have been filed and consolidated in state district court in Harris County, Texas, and thirteen have been filed and consolidated in Delaware Chancery Court. An additional purported class action lawsuit was filed on behalf of unitholders of EPB in the Delaware Chancery Court in December 2011 against El Paso and its board of directors. The lawsuit alleges that the merger transaction with KMI adversely affected the unitholders of EPB and that El Paso and its board of directors breached their fiduciary duties. A motion to dismiss that suit has been filed. We believe these purported shareholder class actions are without merit and we intend to defend against them vigorously.

Brinckerhoff Lawsuit. In December 2011, a derivative lawsuit was filed on behalf of EPB against us and the board of directors of the general partner of EPB associated with a transaction completed in March 2010 involving the sale of interests in Southern LNG Company, L.L.C. (SLNG) and Elba Express to EPB. The lawsuit alleges various conflicts of interest and that the consideration paid in that transaction by EPB was excessive. We believe this action is without merit and we intend to defend against it vigorously.

Retiree Medical Benefits Matters. In 2002, a group of retirees of Case Corporation (Case) filed a lawsuit in federal court in Detroit, Michigan entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation.* In a series of decisions in previous years, the trial court ruled that the retirees are entitled to retiree medical benefits from us pursuant to their Collective Bargaining Agreement and the Case spin-off agreement with one of our predecessors, Tenneco Inc. In addition, we are obligated to pay damages incurred by retirees prior to the court s entry of an injunction requiring us to pay the cost of the coverage. We settled the case in 2011 and the settlement has been approved by the court and is final. We are in the process of implementing the settlement which includes amending the level of benefits (see Note 13 for a further discussion) and having participants submit claims for the damages incurred before the effective date of the injunction. We believe our accruals established for this matter are adequate.

Cash Balance Plan Lawsuit. In December 2004, a purported class action lawsuit entitled *Tomlinson, et al.v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit alleges various violations of the Employee Retirement Income Security Act (ERISA) and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. In 2010, a District Court dismissed all of the claims in this matter. The plaintiffs appealed the dismissal of the case and in August 2011 the Court of Appeals for the Tenth Circuit affirmed the District Court s decision. The plaintiffs filed a petition with the United States Supreme Court to review the case, which was denied. The matter is now resolved with no liability on the part of El Paso or the El Paso Corporation Pension Plan.

Price Reporting Litigation. Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which were pending in Nevada, were dismissed. Appeals have been filed. Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, our costs and legal exposure related to the remaining outstanding lawsuits and claims are not currently determinable.

MTBE. Certain of our subsidiaries used, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies seeking different remedies against us and many other defendants, including remedial activities, damages, attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation (MDL) in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. Ninety-seven of the cases have been settled or dismissed, and most of the settlements have been substantially funded by insurance. We have two remaining lawsuits, both pending in the MDL. Based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, our costs and legal exposure related to these remaining lawsuits are not currently determinable.

Other. In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters, including those discussed above, cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2011, we had approximately $38 million accrued for all of our outstanding legal proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In April 2010, the FERC approved an offer of settlement of EPNG s rate case which increased its base tariff rates, effective January 1, 2009. As part of the settlement, EPNG made refunds to its customers in 2010. The settlement resolved all but four issues in the rate proceeding. In January 2011, the Presiding Administrative Law Judge issued a decision that for the most part found against EPNG on the four issues. EPNG has appealed those decisions to the FERC and may also seek review of any of the FERC s decisions to the U.S. Court of Appeals. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates which would increase revenues by approximately $100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. A hearing commenced in late October 2011 and concluded in December 2011. A decision is due in May 2012. It is uncertain whether such an increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of the hearing in the rate case. Although the final outcome of this matter is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In December 2011, the FERC approved TGP s settlement that resolved the outstanding issues arising from its general rate case filing. The settlement provides for, among other things, (i) an increase in TGP s base tariff rates effective June 1, 2011, (ii) implementation of cost trackers for fuel, pipeline safety and greenhouse gas, (iii) significant contract extensions to October 2014, (iv) a filing requirement for its next general rate case to be effective no earlier than April 2014 but no later than November 2015, and (v) a revenue sharing mechanism with certain of its customers for certain revenues above an annual threshold. In addition, as part of the settlement, TGP will refund approximately $68 million to its customers by March 31, 2012. We believe the accruals established for this matter are adequate.

In addition to the provisions discussed above, the settlement also required TGP to reduce its regulatory liabilities associated with its postretirement benefit plan and certain deferred taxes. We have reflected these adjustments as an increase to our operating revenues of approximately $40 million since these items were provided for under prior rate settlements and there is no funding requirement or cost recovery in our current rates for these items. For a further discussion of these regulatory assets and liabilities, see Note 8.

CIG Rate Case. In August 2011, the FERC approved an uncontested pre-filing settlement of CIG s rate case required under the terms of a previous settlement. The settlement generally provides for (i) CIG s current tariff rates to continue until its next general rate case which will be effective no earlier than October 1, 2014 but no later than

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October 1, 2016; (ii) contract extensions to March 2016; (iii) a revenue sharing mechanism with certain of its customers for certain revenues above annual threshold amounts; and (iv) a revenue surcharge mechanism with certain of its customers to charge for certain shortfalls of revenue less than an annual threshold amount.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at current and former operating sites. At December 31, 2011, we had accrued approximately $181 million for environmental matters, which has not been reduced by $18 million for amounts to be paid directly under government sponsored programs or through settlement arrangements with third parties. Our accrual includes approximately $178 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $3 million for related environmental legal costs.

Our estimates of potential liability range from approximately $181 million to approximately $321 million. Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	December 31, 2011	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 9	$ 13
Non-operating	160	273
Superfund	12	35
Total	$ 181	$ 321

Superfund Matters. Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as Superfund, or state equivalents for 28 active sites. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

For 2012, we estimate that our total remediation expenditures will be approximately $67 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $19 million in the aggregate for the years 2012 through 2016, including capital expenditures associated with the impact of the EPA rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

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Commitments, Purchase Obligations and Other Matters

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space, operating facilities and equipment. The terms of the agreements vary from 2012 until 2053. Future minimum annual rental commitments under our operating leases net of minimum sublease rentals at December 31, 2011, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2012	$ 14
2013	13
2014	13
2015	9
2016	7
Thereafter	8
Total	$ 64

Rental expense was $38 million for the year ended December 31, 2011 and $39 million for each of the years ended December 31, 2010 and 2009 and is reflected in operation and maintenance expense. Included in rental expense is approximately $20 million in each period associated with right-of-way and other arrangements, principally related to a long-term commitment which extends through 2025.

Guarantees and Indemnifications. We are involved in various joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, 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 amount to an unlimited dollar amount, depending on the nature of the claim, specificity as to duration, and the particular transaction. Those arrangements with a specified dollar amount have a maximum stated value of approximately $710 million, which is comprised of a $438 million indemnification associated with the sale of ANR Pipeline Company (ANR), a $120 million indemnification associated with the sale of our Macae power facility in Brazil, and $152 million of indemnifications and guarantees related to the sale of other legacy assets. During the fourth quarter of 2011, we received a full claim against our Macae indemnification for matters that we believe are specifically excluded from the scope of the indemnification. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 11. 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 of 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, 2011 and 2010 we have recorded obligations of $15 million and $18 million related to our guarantee and indemnification arrangements. Our 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 estimated fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification. We believe that our guarantee and indemnification agreements for which we have not recorded a liability are not probable of resulting in future losses based on our assessment of the nature of the guarantee, the financial condition of the guaranteed party and the period of time that the guarantee has been outstanding, among other considerations.

Other Commitments and Purchase Obligations. In 2009, the FERC approved an amendment to the 1995 FERC settlement with TGP that provides for interim refunds over a three year period of approximately $157 million plus interest of 8% for amounts collected related to certain environmental costs. As of December 31, 2011, TGP has refunded approximately $138 million to its customers and expects to refund the remaining obligation (recorded as other current liabilities on our balance sheet) of approximately $40 million during 2012. We also have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2011, we had (i) firm commitments under transportation and storage capacity contracts of $1,150 million, approximately half of which will be paid over the next 5 years and (ii) other purchase and capital commitments (including drilling, maintenance, engineering, procurement and construction contracts) of approximately $230 million, the majority of which is due in less than one year.

We also hold cancelable easements or right-of-way arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems. See *Operating Leases* above.

13. Retirement Benefits

Overview of Retirement Benefit Plans

Pension Plans. Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat, Inc. or The Coastal Corporation receive the greater of their cash balance benefits or their transition benefits under the prior plan formulas. We do not anticipate making any contributions to our cash balance pension plan in 2012.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We expect to contribute $4 million to the SERP in 2012.

Retirement Savings Plan. We maintain a defined contribution plan covering all of our U.S. employees. We match 75 percent of participant basic contributions up to six percent of eligible compensation and can make additional discretionary matching contributions depending on the overall performance of the Company relative to its peers. Amounts expensed under this plan were approximately $38 million, $39 million and $19 million for the years ended December 31, 2011, 2010 and 2009. For 2011 and 2010, the amounts expensed include an additional discretionary matching contribution.

Other Postretirement Benefit Plans. We provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees (such as to certain retirees of Case as further described in Note 12) and limited postretirement life insurance benefits for current and retired employees. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits. OPEB plans for certain of our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. For further information, see Notes 1 and 8. We expect to contribute $32 million to our other postretirement benefit plans in 2012.

Other Matters. In conjunction with the settlement of the Case matter described in Note 12, we amended the OPEB plan in which the plaintiffs are participants to align the benefits in that plan with the settlement agreement. The impact of this amendment is reflected in our OPEB liability and accumulated other comprehensive income as of December 31, 2011.

Benefit Obligation, Plan Assets and Funded Status. In accounting for our pension and OPEB 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 certain of our regulated operations, or in accumulated other comprehensive income (loss) for all other operations until those gains and losses are recognized in the income statement. During 2011, we reclassified $19 million, net of taxes of $6 million, from a net regulatory liability to accumulated other comprehensive income pursuant to rate case settlements whereby these amounts are no longer included in the rates we will charge our customers for certain of our regulated operations.

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The table below provides information about our pension and OPEB plans as of and for each of the years ended December 31.

	Pension Benefits		OPEB	
	2011	2010	2011	2010
	(In millions)			
Change in benefit obligation:[1]				
Benefit obligation beginning of period	$ 2,218	$ 2,133	$ 659	$ 642
Service cost	21	19		
Interest cost	107	115	30	33
Participant contributions			6	6
Actuarial loss	164	130	37	28
Benefits paid[2]	(165)	(179)	(44)	(50)
Case plan amendment (Note 12)			(98)	
Benefit obligation end of period	$ 2,345	$ 2,218	$ 590	$ 659
Change in plan assets:				
Fair value of plan assets beginning of period	$ 2,048	$ 1,979	$ 265	$ 243
Actual return on plan assets[3]	40	244	10	22
Employer contributions	4	4	38	49
Participant contributions			6	6
Benefits paid	(165)	(179)	(50)	(55)
Fair value of plan assets end of period	$ 1,927	$ 2,048	$ 269	$ 265
Reconciliation of funded status:				
Fair value of plan assets	$ 1,927	$ 2,048	$ 269	$ 265
Less: Benefit obligation	2,345	2,218	590	659
Net liability at December 31	$ (418)	$ (170)	$ (321)	$ (394)

(1) The benefit obligation for our pension plans represents the projected benefit obligation and the benefit obligation for our OPEB plans represents the accumulated postretirement benefit obligation.

(2) Amounts for OPEB are shown net of a subsidy of approximately $6 million and $5 million for each of the years ended December 31, 2011 and 2010 related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

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

Components of Funded Status. The following table details the amounts recognized in our balance sheet at December 31, 2011 and 2010 related to our pension and OPEB plans.

	Pension Benefits		OPEB	
	2011	2010	2011	2010
	(In millions)			
Non-current benefit asset	$	$	$ 111	$ 106
Current benefit liability	(4)	(4)	(31)	(40)
Non-current benefit liability	(414)	(166)	(401)	(460)
Funded status	$ (418)	$ (170)	$ (321)	$ (394)

Components of Accumulated Other Comprehensive Income (Loss). The following table details the amounts recognized in accumulated other comprehensive income (loss), net of income taxes at December 31, 2011 and 2010 related to our pension and OPEB plans.

	Pension Benefits		OPEB	
	2011	2010	2011	2010
	(In millions)			
Unrecognized net gain (loss)	$ (805)	$ (689)	$ 7	$ 23
Unamortized prior service credit (cost)	(15)	(16)	62	
Accumulated other comprehensive income (loss)	$ (820)	$ (705)	$ 69	$ 23

We anticipate that approximately $53 million of our accumulated other comprehensive loss, net of tax, will be recognized as part of our net periodic benefit cost in 2012.

Our accumulated benefit obligation for our defined benefit pension plans was $2.3 billion and $2.2 billion at December 31, 2011 and 2010. Our accumulated benefit obligation for our defined benefit pension plans, whose accumulated benefit obligations exceeded the fair value of plan assets, was $2.3 billion and $2.2 billion as of December 31, 2011 and 2010. The fair value of these plans assets was approximately $1.9 billion and $2.0 billion at December 31, 2011 and 2010.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $435 million and $558 million as of December 31, 2011 and 2010. The fair value of these plans assets was $3 million and $58 million at December 31, 2011 and 2010.

Plan Assets. The primary investment objective of our plans is to ensure that over the long-term life of the plans an adequate pool of sufficiently liquid assets exists to meet the benefit obligations to participants, retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is generally the result of economic and capital market conditions. The plans investments include a wide diversification of asset types, fund strategies and fund managers. Although actual allocations vary from time to time from our targeted allocations, the target allocations for our pension plans assets are 50 percent equity securities, 40 percent fixed income securities and 10 percent of other types of investments. The target allocations for our OPEB plans assets are 65 percent equity and 35 percent fixed income securities. Equity securities for our pension plans assets may include investments in large-cap, mid-cap and small-cap companies in the United States, as well as investments in foreign companies. Fixed income securities may include corporate bonds of companies from diversified industries, as well as international fixed income securities, United States Treasuries, and stable income products such as investment contracts. Other types of investments may include hedge funds and real estate investments that follow several different strategies. For our OPEB plans, we may invest plan assets in a manner that replicates, to the extent feasible, the Russell 3000 Index and the Barclays Capital Aggregate Bond Index to achieve equity and fixed income diversification, respectively.

Below are the details of our pension and OPEB plans assets classified by level and a description of their fair values.

Level 1 assets fair values are based on quoted prices for the instruments in actively traded markets. Included in this level are interest bearing cash, equity securities, an exchange traded mutual fund and other securities.

Level 2 assets fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are common/collective trust funds, mutual funds, fixed income securities and other securities. The common/collective trust funds and mutual funds fair values are primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. For common collective trust funds and mutual funds, certain restrictions on redemption exist as of December 31, 2011 where the issuer reserves the right to temporarily delay withdrawal in certain situations such as market conditions or at the issuer s discretion. The fixed income securities fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market.

Level 3 assets fair values are similar to Level 2 assets and calculated using valuation techniques that require inputs that are both significant to the fair value measurement and unobservable. Included in this level are a limited partnership and a mutual fund. The fair value of these investments is primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date.

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Listed below are the fair values of our pension and OPEB plans assets that are recorded at fair value classified in each level at December 31, 2011 and 2010 (in millions):

	Pension Assets							
	2011				2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Interest bearing cash	$ 1	$	$	$ 1	$ 1	$	$	$ 1
Equity securities:								
Domestic companies	511			511	582			582
Foreign companies	92			92	107			107
Fixed income securities:								
Corporate bonds		55		55		49		49
U.S. treasuries and agency		85		85		66		66
Municipal		9		9		6		6
Federal mortgage-backed and other		28		28		25		25
Common collective trust funds[1]		891		891		1,051		1,051
Mutual funds[2]		131	37	168		122	39	161
Other investments	1	74	12	87				
Total assets at fair value	$ 605	$ 1,273	$ 49	$ 1,927	$ 690	$ 1,319	$ 39	$ 2,048

(1) For 2011, this category includes common/collective trust funds which are invested in approximately 54 percent fixed income, 42 percent equity and 4 percent short term securities. For 2010, this category includes common/collective trust funds which are invested in approximately 51 percent fixed income, 46 percent equity, and 3 percent short term securities.

(2) For 2011, this category includes mutual funds which are invested in approximately 45 percent fixed income and 55 percent other investments. For 2010, this category includes mutual funds which are invested in approximately 59 percent fixed income and 41 percent other investments.

	OPEB Assets					
	2011			2010		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Exchange traded mutual fund	$ 12	$	$ 12	$ 12	$	$ 12
Common/collective trust funds[1]		257	257		253	253
Total assets at fair value	$ 12	$ 257	$ 269	$ 12	$ 253	$ 265

(1) This category includes common collective trust funds which are invested in approximately 65 percent equity and 35 percent fixed income securities.

The following table presents the changes in our pension plan assets included in Level 3 for the years ended December 31, 2011 and 2010:

	Balance at Beginning of Period	Unrealized gains (losses), net	Purchases	Balance at End of Period
	(In millions)			
December 31, 2011:				
Mutual fund	$ 39	$ (2)	$	$ 37
Other investment			12	12

Total	$ 39	$ (2)	$ 12	$ 49
December 31, 2010:				
Mutual fund	$	$ 1	$ 38	$ 39
Total	$	$ 1	$ 38	$ 39

Expected Payment of Future Benefits. As of December 31, 2011, we expect the following benefit payments under our plans:

Year Ending December 31,	**Pension Benefits**	**OPEB**[1]
	(In millions)	
2012	$ 186	$ 46
2013	189	46
2014	187	46
2015	186	45
2016	186	45
2017-2021	890	210

(1) Includes a reduction of approximately $7 million in each of the years 2012-2016 and approximately $34 million in aggregate for 2017-2021 for an expected subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

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Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2011, 2010 and 2009:

	Pension Benefits			OPEB		
	2011	2010 (Percent)	2009	2011	2010 (Percent)	2009
Assumptions related to benefit obligations:						
Discount rate	4.32	5.01	5.61	4.35	4.83	5.42
Rate of compensation increase	4.30	4.09	4.20			
Assumptions related to benefit costs:						
Discount rate	5.01	5.61	6.33	4.83	5.42	5.98
Expected return on plan assets[1]	8.00	8.00	8.00	7.75	7.75	8.00
Rate of compensation increase	4.09	4.20	4.18			

(1) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. We utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income tax at a rate of 35 percent.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 7.3 percent, gradually decreasing to 5.0 percent by the year 2019. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2011 and 2010:

	2011	2010
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 2	$ 3
Accumulated postretirement benefit obligation	47	49
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (2)	$ (2)
Accumulated postretirement benefit obligation	(41)	(43)

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

	Pension Benefits			OPEB		
	2011	2010	2009 (In millions)	2011	2010	2009
Service cost	$ 21	$ 19	$ 19	$	$	$
Interest cost	107	115	121	30	33	38
Expected return on plan assets	(145)	(157)	(172)	(14)	(13)	(12)
Amortization of net actuarial loss (gain)	91	73	45	(2)	(3)	
Amortization of prior service cost (credit)	1	1	(1)			(1)
Net benefit cost	$ 75	$ 51	$ 12	$ 14	$ 17	$ 25

Components of Other Comprehensive Income (Loss). The following table details the amounts recognized in our other comprehensive loss, net of income taxes, for the years ended December 31, 2011, 2010, and 2009 related to our pension and OPEB plans.

	Pension Benefits			OPEB		
	2011	2010	2009	2011	2010	2009
			(In millions)			
Prior service credit (cost)	$	$	$ (10)	$ 62	$	$
Net actuarial gain (loss)	(177)	(28)	27	(16)	(18)	19
Amortization of net actuarial loss (gain)	61	47	29		(2)	
Amortization of prior service cost (credit)	1	1	(1)			(1)
Other comprehensive income (loss)	$ (115)	$ 20	$ 45	$ 46	$ (20)	$ 18

14. Equity and Noncontrolling Interests

Convertible Perpetual Preferred Stock. In March 2011, we exercised our conversion right related to $750 million of convertible perpetual preferred stock. Upon conversion, holders of our convertible preferred stock received approximately 57.9 million shares of common stock (approximately 77.2295 shares of El Paso common stock for each share of preferred stock converted).

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

	Common Stock ($0.01/Share)	Convertible Preferred Stock (4.99%/Year)
Amount paid in 2011	$ 29	$ 9
Amount paid in January 2012	$ 8	$
Declared in 2012:		
Date of declaration	February 23, 2012	
Payable to shareholders on record	March 5, 2012	
Date payable	April 2, 2012	

Dividends on our common stock and preferred stock are treated as reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common stock in 2012 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

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

	2011	2010 (In millions)	2009
Cash flow hedges	$ (42)	$ (69)	$ (36)
Pension and other postretirement benefits (see Note 13)	(754)	(682)	(682)
Total accumulated other comprehensive loss, net of income taxes	$ (796)	$ (751)	$ (718)

Noncontrolling Interests. We are the general partner of EPB, a master limited partnership (MLP). As of December 31, 2011, we own a 44 percent interest in EPB (a 2 percent general partner interest and a 42 percent limited partner interest). During the years ended December 31, 2011, 2010, and 2009 EPB issued noncontrolling interests, net of issuance costs, of $0.9 billion, $1.3 billion and $0.2 billion in conjunction with our contribution to EPB of additional ownership interests in CIG, SNG, Southern LNG Company, L.L.C. (SLNG), which owns the Elba Island LNG receiving terminal, and El Paso Elba Express Company, L.L.C. (Elba Express), which owns the Elba Express Pipeline. As of December 31, 2011, our MLP owns 100 percent of each of these entities, except for CIG, of which it owns 86 percent. The issuance of the EPB common units were reflected in our consolidated statements of equity at December 31, 2011 as an increase of $610 million to noncontrolling interests and an increase of $213 million, net of deferred tax liability, to El Paso Corporation s additional paid in capital. Our net income attributable to El Paso Corporation, together with the increase in El Paso Corporation s additional paid-in capital for the year ended December 31, 2011 totaled $354 million.

In accordance with its partnership agreement, EPB is obligated to make quarterly distributions of available cash to its unitholders. We receive our share of these cash distributions through our limited partner ownership interest, general partner interest, and incentive distribution rights (IDR s) we hold as the general partner. Prior to February 15, 2011, we held subordinated units in EPB. Upon payment of the quarterly cash distribution for the fourth quarter of 2010, the financial tests required for the conversion of subordinated units into common units were satisfied. As a result, our subordinated units were converted on February 15, 2011 into common units on a one-for-one basis effective January 3, 2011.

To the extent that the consideration for the sales of assets to EPB is not in the form of additional equity in EPB, our interest in our assets becomes diluted over time. However our economic interest will benefit from the receipt of incentive distributions in accordance with the partnership agreement.

Our IDRs pay an increasing percentage interest in quarterly distributions of cash based on the level of distribution to all unitholders. As the holder of these rights we can elect to relinquish the right to receive incentive distribution payments and reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments would be set. We are currently entitled to receive the maximum level of incentive distributions.

For additional information regarding our master limited partnership, see Note 11.

Net Income Attributable to Noncontrolling Interests. The components of net income attributable to noncontrolling interests on our statements of income for the year ended December 31, are as follows:

	2011	2010	2009
		(In millions)	
EPB	$ 221	$ 118	$ 60
Preferred Stock of Cheyenne Plains (Note 18)	15	21	5
Preferred Stock of Ruby (Note 18)	50	27	
Net income attributable to noncontrolling interests	$ 286	$ 166	$ 65

15. Stock-Based Compensation

Overview. Under our stock-based compensation plans, we issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. Pursuant to the merger agreement with KMI, on closing of the merger, all unvested stock-based compensation awards will immediately vest and become exercisable, with performance shares vesting at 100 percent of targeted shares. At that time, all unrecognized stock-based compensation expense will accelerate. The disclosures and tables that follow are based on the existing terms of our stock-based compensation awards and do not reflect any impacts of the merger agreement with KMI.

We are currently authorized to grant awards of approximately 62 million shares of our common stock under our current plans, which includes 54.5 million shares under our Omnibus plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At December 31, 2011, approximately 17.3 million shares remain available for grant under our current plans, which includes approximately 13.8 million shares under our Omnibus plan, 1.5 million shares under our non-employee director plan and 2 million shares under our employee stock purchase plan. We also have approximately 4 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

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

Non-Qualified Stock Options. We grant non-qualified stock options to our employees at an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally vest in equal amounts over three years from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the year ended December 31, 2011 is presented below:

	# Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2010	32,228,401	$ 19.58		
Granted	2,324,096	$ 18.13		
Exercised	(5,908,717)	$ 11.52		
Forfeited or canceled	(524,877)	$ 10.30		
Expired	(5,499,826)	$ 60.43		
Outstanding at December 31, 2011	22,619,077	$ 11.82	6.33	$ 334
Vested at December 31, 2011 or expected to vest in the future	22,198,867	$ 11.82	6.29	$ 328
Exercisable at December 31, 2011	14,214,868	$ 11.81	5.17	$ 211

During 2011, 2010 and 2009, we recognized approximately $20 million, $24 million and $23 million of pre-tax compensation expense on stock options, capitalized approximately $3 million, $4 million, and $5 million of this expense as part of fixed assets and generated $7 million, $8 million and $8 million of income tax benefits, respectively. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2011 was approximately $14 million, which is expected to be recognized over a weighted average period of 9 months. Options exercised during the years ended December 31, 2011, 2010 and 2009 had a total intrinsic value of $53 million, $5 million and less than $1 million, generated $68 million, $8 million and $1 million of cash proceeds and generated an unrealized income tax benefit of $19 million during 2011. Options exercised during the years ended December 31, 2010 and 2009 did not generate any significant associated income tax benefits.

Fair Value Assumptions. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management s best estimate at the time of grant. For the years ended December 31, 2011, 2010 and 2009 the weighted average grant date fair value per share of options granted was $7.29, $4.55 and $2.96.

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

	2011	2010	2009
Expected Term in Years	6.0	6.0	6.0
Expected Volatility	40%	40%	54%
Expected Dividends	0.5%	0.5%	1.5%
Risk-Free Interest Rate	2.6%	2.9%	2.0%

We estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and from our historical stock price volatility over the expected term. We estimate the expected term of our option awards based on the vesting period and average remaining contractual term, referred to as the simplified method . We use this method to provide a reasonable basis for estimating our expected term based on insufficient historical data prior to 2006 primarily due to significant changes in the composition of our employees receiving stock-based compensation awards.

Restricted Stock. We grant shares of restricted common stock, which carry voting and dividend rights, to our officers and employees. Sale or transfer of these shares is restricted until they vest. The fair value of our restricted shares is determined on the grant date and these shares generally vest in equal amounts over three years from the date of grant. A summary of the changes in our non-vested restricted shares for the year ended December 31, 2011 is presented below:

Nonvested Shares	# Shares	Weighted Average Grant Date Fair Value per Share
Nonvested at December 31, 2010	5,018,932	$ 10.01
Granted	4,000,400	$ 18.18
Vested	(2,253,916)	$ 10.69
Forfeited	(312,458)	$ 13.15
Nonvested at December 31, 2011	6,452,958	$ 14.69

The weighted average grant date fair value per share for restricted stock granted during 2011, 2010 and 2009 was $18.18, $11.09 and $6.53. The total fair value of shares vested during 2011, 2010 and 2009 was $42 million, $27 million and $13 million.

During 2011, 2010 and 2009, we recognized approximately $42 million, $25 million and $26 million of pre-tax compensation expense on our restricted share awards, and capitalized approximately $6 million, $4 million and $7 million of this expense as part of fixed assets. During 2011 we generated an unrealized income tax benefit of $15 million and in 2010 and 2009 we recorded income tax benefits of $9 million related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2011 was approximately $40 million, which is expected to be recognized over a weighted average period of 10 months.

Performance Shares. Beginning in 2011, we granted approximately 0.7 million performance shares to El Paso officers. The number of performance shares ultimately earned will vary between zero and 200 percent of targeted shares depending on the level of total shareholder return (TSR) relative to that of El Paso s peer group of companies. Our performance shares carry dividend rights and cannot be sold or transferred until they vest. The fair value of the performance-based shares granted is estimated on the day of grant using a Monte-Carlo simulation. Of the awards granted, fifty percent vest at the end of a two year performance period beginning January 1, 2011 with a grant date fair value per share of $27.93 and the remaining fifty percent vest at the end of a three year performance period beginning January 1, 2011 with a grant date fair value per share of $27.64. During 2011, we recognized approximately $6 million of pre-tax compensation expense related to these awards and generated an unrealized income tax benefit of $2 million. At December 31, 2011, the number of shares that we would issue under our 2011 performance grants, assuming the awards were vested and relative TSR performance was determined at that date, would be approximately 1.3 million shares. As of December 31, 2011, all performance shares were unvested with unrecognized compensation cost of approximately $12 million expected to be recognized over a weighted average period of approximately 12 months.

Employee Stock Purchase Plan. Our employee stock purchase plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of current stock compensation accounting standards. Shares issued under this plan were insignificant during 2011, 2010 and 2009.

16. Business Segment Information

As of December 31, 2011, our business consists of two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. A further discussion of each segment and our other activities follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services in the United States. As of December 31, 2011, we conducted our activities primarily through eight wholly or majority owned interstate pipeline systems and equity interests in three transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in three underground natural gas storage facilities and two LNG terminalling facilities.

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

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

Other. Our other activities include our general and administrative functions, midstream operations and miscellaneous businesses.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2011, 2010 and 2009.

We use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our operating businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 and 2009 amounts have been conformed to reflect our current performance measure. Below is a reconciliation of our Segment EBIT to our net income (loss) for the periods ended December 31:

	2011	2010	2009
		(In millions)	
Segment EBIT	$ 1,325	$ 2,341	$ 135
Interest and debt expense	(948)	(1,031)	(1,008)
Income tax benefit (expense)	50	(386)	399
Net income (loss)	427	924	(474)
Net income attributable to non-controlling interests	(286)	(166)	(65)
Net income (loss) attributable to El Paso Corporation	$ 141	$ 758	$ (539)

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

	As of or for the Year Ended December 31, 2011					
	Segment				Other	
	Pipelines	Exploration and Production	Marketing	Other	Reclassifications/ Eliminations	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,933	$ 1,121[1]	$ 553	$ 5	$	$ 4,612
Foreign		112	136			248
Intersegment revenue[2]	121	634	(744)	5	(16)	
Operation and maintenance	874	424	6	90		1,394
Loss on deconsolidation of subsidiary	600[3]					600
Ceiling test charges		152				152
Depreciation, depletion and amortization	478	612		26		1,116
Loss on debt extinguishment				(169)		(169)
Earnings (losses) from unconsolidated affiliates	100	(7)		58[4]		151
Segment EBIT	1,135	494	(61)	(243)		1,325
Assets						
Domestic	18,272	4,613	153	692	21	23,751
Foreign[5]	10	333	19	201		563
Investments in unconsolidated affiliates	2,254	346		139		2,739
Capital expenditures and contributions and advances to equity investments, net[6]	2,100	1,592		112		3,804

(1) Revenues from external customers include gains of $284 million related to our financial derivative contracts associated with our oil and natural gas production.

(2) Our intersegment revenues, along with intersegment expenses, were incurred in the normal course of business between our operating segments. Intersegment revenues primarily represent sales to our Marketing segment, which is responsible for marketing our production to third parties. Additionally, during 2011 TGP sold 9.5 TBtu of natural gas not used in operations to its affiliate, El Paso Marketing, L.P. In June 2011, TGP terminated that contract in connection with the implementation of a fuel volume tracker as part of its rate case filed with the FERC.

(3) Reflects a non-cash loss of approximately $600 million, $475 million of which was based on the difference between the carrying value of Ruby and the estimated fair value of our investment in Ruby, and $125 million of which related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt (see Note 18).

(4) Includes a gain of approximately $16 million related to the sale of our remaining interest in a telecommunications equity investment.

(5) Of total foreign assets, approximately $0.3 billion relates to property, plant and equipment, and approximately $0.1 billion relates to investments in unconsolidated affiliates.

(6) Amounts are net of third party reimbursements of our cash capital expenditures, returns of capital and sales of investments and advances.

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	As of or for the Year Ended December 31, 2010					
	Segment				Other	
	Pipelines	Exploration and Production	Marketing	Other	Reclassifications/ Eliminations	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,768	$ 957[1]	$ 597	$ 62	$	$ 4,384
Foreign	3	86	143			232
Intersegment revenue[2]	49	746	(789)	18	(24)	
Operation and maintenance	785	384	2	64		1,235
Ceiling test charges		25				25
(Gain) loss on long-lived assets[3]	30			(113)		(83)
Depreciation, depletion and amortization	440	477		25		942
Loss on debt extinguishment				(217)		(217)
Earnings (losses) from unconsolidated affiliates	178 [4]	(7)		17		188
Segment EBIT	1,738	727	(50)	(74)		2,341
Assets						
Domestic	19,642	4,243	200	736	(204)	24,617
Foreign[5]	9	414	22	208		653
Investments in unconsolidated affiliates	1,127	399		147		1,673
Capital expenditures and contributions and advances to equity investments, net[6]	2,547	1,380		79		4,006

(1) Revenues from external customers include gains of $390 million related to our financial derivative contracts associated with our oil and natural gas production.

(2) Our intersegment revenues, along with intersegment expenses, were incurred in the normal course of business between our operating segments. Intersegment revenues primarily represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Includes a $110 million gain in Other related to our sale of midstream assets into our newly formed joint venture and $21 million non-cash asset write down in Pipelines based on a FERC order related to the sale of a compressor station and gas processing plant in 2009.

(4) Includes a gain of approximately $80 million related to the sale of our interests in certain Mexican pipeline and compression assets.

(5) Of total foreign assets, approximately $0.4 billion relates to property, plant and equipment, and approximately $0.1 billion relates to investments in and advances to unconsolidated affiliates.

(6) Amounts are net of third party reimbursements of our cash capital expenditures, returns of capital and sales of investments and advances.

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	As of or for the Year Ended December 31, 2009					
	Segment				Other	
	Pipelines	Exploration and Production	Marketing	Other	Reclassifications/ Eliminations	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,711	$ 1,257[1]	$ 497	$ 17	$	$ 4,482
Foreign	10	26	114			150
Intersegment revenue[2]	46	545	(582)		(10)	(1)
Operation and maintenance	807	392	8	28		1,235
Ceiling test charges		2,123				2,123
(Gain) loss on long-lived assets	(2)	25		(1)		22
Depreciation, depletion and amortization	414	440		13		867
Earnings (losses) from unconsolidated affiliates	92	(30)		5		67
Segment EBIT	1,481	(1,349)	20	(17)		135
Assets						
Domestic	17,090	3,574	321	697	(117)	21,565
Foreign[3]	234	451	24	231		940
Investments in unconsolidated affiliates	1,133	456		129		1,718
Capital expenditures and contributions and advances to equity investments, net[4]	1,710	1,154		(110)		2,754

(1) Revenues from external customers include gains of $687 million related to our financial derivative contracts associated with our oil and natural gas production.

(2) Our intersegment revenues, along with intersegment expenses, were incurred in the normal course of business between our operating segments. Intersegment revenues primarily represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Of total foreign assets, approximately $0.4 billion relates to property, plant and equipment and approximately $0.3 billion relates to investments in and advances to unconsolidated affiliates.

(4) Amounts are net of third party reimbursements of our cash capital expenditures, returns of capital and sales of investments and advances.

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17. Accounts Receivable Sales Programs

Accounts Receivable Sales Programs. We participate in accounts receivable sales programs where several of our pipeline subsidiaries sell receivables in their entirety to a third-party financial institution (through wholly-owned special purpose entities). The sale of these accounts receivable (which are short-term assets that generally settle within 60 days) qualify for sale accounting. The third party financial institution involved in these accounts receivable sales programs acquires interests in various financial assets and issues commercial paper to fund those acquisitions. We do not consolidate the third party financial institution because we do not have the power to control, direct, or exert significant influence over its overall activities since our receivables do not comprise a significant portion of its operations.

In connection with our accounts receivable sales, we receive a portion of the sales proceeds up front and receive an additional amount upon the collection of the underlying receivables (which we refer to as a deferred purchase price). Our ability to recover the deferred purchase price is based solely on the collection of the underlying receivables. The table below contains information related to our accounts receivable sales programs.

	Year Ended December 31,	
	2011	2010
	(In millions)	
Accounts receivable sold to the third-party financial institution[1]	$ 2,547	$ 2,536
Cash received for accounts receivable sold under the programs	1,421	1,478
Deferred purchase price related to accounts receivable sold	1,126	1,058
Cash received related to the deferred purchase price	1,085	967
Amount paid in conjunction with terminated programs[2]		90

(1) During the years ended December 31, 2011 and 2010, losses recognized on the sale of accounts receivable were immaterial.

(2) In January 2010, we terminated our previous accounts receivable sales programs and paid $90 million to acquire the related senior interests in certain receivables under those programs. During 2009, we sold approximately $1.9 billion of accounts receivable under those programs and our fees and losses related to these programs were not material.

	As of December 31,	
	2011	2010
	(In millions)	
Accounts receivable sold and held by third-party financial institution	$ 254	$ 210
Uncollected deferred purchase price related to accounts receivable sold[1]	130	89

(1) Initially recorded at an amount which approximates its fair value as a Level 2 measurement.

The deferred purchase price related to the accounts receivable sold is reflected as other accounts receivable on our balance sheet. Because the cash received up front and the deferred purchase price relate to the sale or ultimate collection of the underlying receivables, and are not subject to significant other risks given their short term nature, we reflect all cash flows under the accounts receivable sales programs as operating cash flows on our statement of cash flows. Under the accounts receivable sales programs, we service the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the years ended December 31, 2011, 2010 and 2009.

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

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. The earnings from unconsolidated affiliates reflected in our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments, gains and losses on divestitures and other adjustments recorded by us. As of December 31, 2011, the net equity in the underlying net assets of these investments exceeded our investment balance by $245 million. As of December 31, 2010, our investment balance exceeded the net equity in the underlying net assets of these investments by $98 million. The difference in these balances primarily relates to purchase price adjustments for certain of our investments, net of impairments and/or differences resulting from the deconsolidation of certain entities. The information below related to our unconsolidated affiliates includes (i) our net investment and earnings (losses) we recorded from these investments, including amortization and/or impairments of our investments, (ii) summarized financial information of these investments, and (iii) revenues and charges with our unconsolidated affiliates. Our net ownership interest, investments in, and earnings (losses) from our unconsolidated affiliates are as follows as of and for the years ended December 31:

	Net Ownership Interest		Investment		Earnings (Losses) from Unconsolidated Affiliates		
	2011	2010	2011	2010	2011	2010	2009
	(Percent)		(In millions)		(In millions)		
Ruby[1]	(1)		$ 1,066	$	$ (1)	$	$
Citrus[2]	50	50	916	822	93	92	66
Four Star[3]	49	49	340	393	(7)	(7)	(30)
Gulf LNG[4]	50	50	242	266	6	(5)	(2)
Bolivia to Brazil Pipeline[5]	10	10	110	104	21	12	(2)
Gasoductos de Chihuahua[6]						88	25
Other	various	various	65	88	39[7]	8	10
Total			$ 2,739	$ 1,673	$ 151	$ 188	$ 67

(1) We own all of the common interests of Ruby and our partner owns all of the convertible preferred interests in Ruby. We amortize a portion of the difference between our underlying equity in the net assets of Ruby and our investment balance.

(2) As of December 31, 2011, we had outstanding receivables of approximately $37 million, included in other long term assets, related to a promissory note from Citrus whereby we will lend up to $150 million.

(3) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $34 million for the year ended December 31, 2011, $38 million for the year ended December 31, 2010, and $48 million for the year ended December 31, 2009, included above. We amortize and generally assess the recoverability of our investment based on the development and production of the underlying estimated proved oil and natural gas reserves of Four Star. The fair value of our investment in Four Star could decline as a result of lower natural gas prices and we may be required to record an impairment of the carrying value in the future.

(4) As of December 31, 2011 and 2010, we had outstanding advances and receivables of $165 million and $85 million, included in current and other long term assets, related to our investment in Gulf LNG.

(5) We own 33 percent of BBPP Holdings Ltd., which owns 29 percent of the Bolivia to Brazil Pipeline.

(6) In 2010, we completed the sale of our interest in this investment and recorded a pretax gain of approximately $80 million. See Note 2.

(7) Includes a gain of approximately $16 million related to the sale of our remaining interest in a telecommunications equity investment.

We received distributions and dividends from our unconsolidated affiliates of approximately $61 million, $64 million and $90 million for the years ended December 31, 2011, 2010 and 2009. During 2010, we made a capital contribution of $100 million to Citrus, one of our unconsolidated affiliates.

Ruby. Prior to September 2011, we reflected Ruby as a consolidated variable interest entity because we were its primary beneficiary. In September 2011, we met certain conditions of our lenders and our partner, Global Infrastructure Partners (GIP), and El Paso s guarantee of GIP s preferred interests in Ruby and Cheyenne Plains Investment Company, L.L.C. (Cheyenne Plains) expired. Accordingly, we no longer reflect approximately $769 million of preferred stock of subsidiaries between liabilities and equity on our balance sheet, which included $700 million of GIP s investment in convertible preferred stock of subsidiaries and $69 million in accrued preferred returns. As a

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result of meeting these conditions, GIP transferred its $145 million convertible preferred interests in Cheyenne Plains to us in exchange for additional convertible preferred interests in Ruby. Following these events, Ruby and Cheyenne Plains were no longer considered variable interest entities. Although we continue to operate the Ruby pipeline, we do not have a controlling financial interest in Ruby; therefore, we deconsolidated it prospectively in our financial statements.

Prior to deconsolidation, Ruby s individual assets and liabilities were reflected on our balance sheet and its income or loss was reflected on our income statement. GIP s returns on its preferred interests in Ruby and Cheyenne Plains were recorded in net income attributable to noncontrolling interests on our income statement. Upon Ruby s deconsolidation in September 2011, we no longer reflect the individual assets and liabilities of Ruby on our balance sheet and began recording Ruby s results in earnings from unconsolidated affiliates on our income statement. At the time of deconsolidation, amounts on our balance sheet consisted primarily of approximately $3,673 million in property, plant and equipment, $348 million in regulatory and other assets, $125 million in price risk management liabilities associated with interest rate swaps on Ruby s debt, $138 million in other liabilities, and $1,447 million in long term debt.

Upon deconsolidation, we were required to assess our investment in Ruby for impairment based on fair value, which is a different model than assessing recoverability of the Ruby pipeline based on estimated undiscounted cash flows while it was consolidated. Our fair value assessment was based on a number of factors, including the present value of anticipated distributable cash flows to be produced from the underlying operations of the Ruby investment. Assessing these cash flows required the use of assumptions related to the future demand for Ruby s operations, forecasted commodity prices and interest rates, anticipated economic conditions, timing of GIP s conversion of their preferred interest into a common equity interest, and other inputs, many of which are not available as observable market data. As a result, our estimate of fair value was a Level 3 fair value measurement. As a result of the deconsolidation of Ruby and our fair value assessments, we recorded a non-cash loss of approximately $475 million based on the difference between the carrying value of Ruby and the estimated fair value of our investment in Ruby and a non-cash loss of $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt.

Summarized Financial Information of Unconsolidated Affiliates. Below is summarized financial information of the operating results and financial position of our unconsolidated affiliates.

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Operating results data:			
Operating revenues	$ 1,373	$ 975	$ 1,041
Operating expenses	723	505	521
Net income	536	489	380
Financial position data:			
Current assets	$ 623	$ 268	
Non-current assets	11,955	7,764	
Short-term debt	876	27	
Other current liabilities	383	396	
Long-term debt	4,415	3,304	
Other non-current liabilities	1,524	1,130	
Equity	5,380	3,175	

Our revenues, expenses and other transactions with unconsolidated affiliates were not material in 2011, 2010 and 2009.

Other Investment-Related Matters. We currently have outstanding disputes and other matters related to an investment in two Brazilian power plant facilities (Manaus/Rio Negro) formerly owned by us. We have filed lawsuits to collect amounts due to us (approximately $62 million of Brazilian reais-denominated accounts receivable) by the plant s power purchaser, which are also guaranteed by the purchaser s parent, Eletrobras, Brazil s state-owned utility. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would fully offset our accounts receivable. Absent resolution of these matters through settlement, we anticipate that the ultimate resolution will likely occur through legal proceedings in the Brazilian courts. We believe the receivables are collectible and therefore have not established an allowance against the receivables owed.

We have reviewed our obligations under the power purchase agreements and have accrued what we believe is an appropriate amount in relation to the asserted counterclaims. We believe the remaining counterclaims are without merit. Based on the anticipated timing of the resolution of the legal proceedings, we have classified our accounts receivable and the accrual for the counterclaims as a non-current asset and liability in our financial statements.

Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately $76 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser has been indemnifying our project companies for these ICMS taxes, along with related interest and penalties. In the third quarter of 2010, a court hearing the Rio Negro case seized funds from certain of the Rio Negro project company s bank accounts in partial satisfaction of and as security for this potential tax liability. In order to prevent collection efforts by the tax authorities for this matter against our project companies, security must be provided for the potential tax liability to the court s satisfaction. The power purchaser and the taxing authorities have agreed upon the posting of shares in a subsidiary of the power purchaser s parent as security. The courts hearing the Rio Negro and Manaus cases have now accepted these shares as security and the court in the Rio Negro case has now lifted its order in respect of the project company s assets. Until this matter is fully resolved, our ability to collect the amounts due to us from the power purchaser could be impacted. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser s parent. We do not believe that we will be required to pay any amounts related to this matter, and accordingly we have not established any accruals for this matter.

The ultimate resolution of the matters discussed above is unknown at this time, and adverse developments related to either our ability to collect amounts due to us or related to these disputes and claims could require us to record additional losses in the future.

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Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(In millions, except per common share amounts)				
2011					
Operating revenues	$ 989	$ 1,236	$ 1,403	$ 1,232	$ 4,860
Operating income (loss)	307	529	(121)	417	1,132
Earnings from unconsolidated affiliates	30	32	36	53	151
Net income (loss)	136	339	(293)	245	427
Net income (loss) attributable to El Paso Corporation	62	262	(368)	185	141
Basic earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.09	0.34	(0.48)	0.24	0.19
Diluted earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.08	0.34	(0.48)	0.24	0.18
2010					
Operating revenues	$ 1,401	$ 1,018	$ 1,213	$ 984	$ 4,616
Operating income (loss)	760	384	518	381	2,043
Earnings from unconsolidated affiliates	28	111	28	21	188
Net income (loss)	419	186	183	136	924
Net income (loss) attributable to El Paso Corporation	388	157	142	71	758
Net income (loss) attributable to El Paso Corporation s common stockholders	379	147	133	62	721
Basic earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.54	0.21	0.19	0.09	1.03
Diluted earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.51	0.21	0.19	0.09	1.00

Below are items affecting comparability of amounts reported in the respective quarters of 2011 and 2010:

December 31, 2011. We recorded (i) a $71 million tax benefit from the conversion of a subsidiary to a limited liability company, (ii) a $40 million increase to operating revenues as a result of a rate case settlement and (iii) $10 million of gains related to changes in fair value of our exploration and production financial derivatives.

September 30, 2011. We recorded (i) a $600 million non-cash loss on the deconsolidation of Ruby, (ii) $251 million of gains related to changes in fair value of our exploration and production financial derivatives, (iii) a $152 million non-cash Brazilian ceiling test charge and (iv) $101 million of losses associated with the repurchase of debt.

June 30, 2011. We recorded (i) $132 million of gains related to changes in the fair value of our exploration and production financial derivatives and (ii) $27 million of losses associated with the repurchase of debt.

March 31, 2011. We recorded (i) $109 million of losses related to changes in the fair value of our exploration and production financial derivatives and (ii) $41 million of losses associated with the repurchase of debt.

December 31, 2010. We recorded (i) a $113 million loss on a debt extinguishment, (ii) a $110 million gain on sale of midstream assets into a joint venture and (iii) $78 million of losses related to changes in fair value of our exploration and production financial derivatives.

September 30, 2010. We recorded (i) $184 million of gains related to changes in fair value of our exploration and production financial derivatives and (ii) a $104 million loss on a debt extinguishment.

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June 30, 2010. We recorded (i) an $80 million gain on sale of our interests in certain Mexican pipeline and compression assets in earnings from unconsolidated affiliates and (ii) $31 million of gains related to changes in fair value of our exploration and production financial derivatives.

March 31, 2010. We recorded $253 million of gains related to changes in fair value of our exploration and production financial derivatives.

Supplemental Oil and Natural Gas Operations (Unaudited)

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

Capitalized Costs. Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	U.S.	Brazil and Egypt[1]	Worldwide
2011 Consolidated:			
Oil and natural gas properties:			
Costs subject to amortization	$ 20,156	$ 1,284	$ 21,440
Costs not subject to amortization	399	82	481
	20,555	1,366	21,921
Less accumulated depreciation, depletion and amortization	16,837	1,087	17,924
Net capitalized costs	$ 3,718	$ 279	$ 3,997
2011 Unconsolidated Affiliate Four Star[2]*:*			
Oil and natural gas properties	$ 628	$	$ 628
Less accumulated depreciation, depletion and amortization	489		489
Net capitalized costs	$ 139	$	$ 139
2010 Consolidated:			
Oil and natural gas properties:			
Costs subject to amortization	$ 19,676	$ 1,091	$ 20,767
Costs not subject to amortization	537	248	785
	20,213	1,339	21,552
Less accumulated depreciation, depletion and amortization	16,993	902	17,895
Net capitalized costs	$ 3,220	$ 437	$ 3,657
2010 Unconsolidated Affiliate Four Star[2]*:*			
Oil and natural gas properties	$ 614	$	$ 614
Less accumulated depreciation, depletion and amortization	466		466
Net capitalized costs	$ 148	$	$ 148

(1) Capitalized costs for Egypt were $74 million and $66 million as of December 31, 2011 and 2010, included in costs not subject to amortization. During 2011, we recorded a ceiling test charge of $152 million in our Brazilian full cost pool. During 2010, we recorded a ceiling test charge of $25 million in our Egyptian full cost pool.

(2) Amounts represent our approximate 49 percent equity interest in the underlying oil and gas assets of Four Star. Four Star applies the successful efforts method of accounting for its oil and gas properties.

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

	U.S.	Brazil and Egypt[(1)]	Worldwide
2011 Consolidated:			
Property acquisition costs			
Proved properties	$	$	$
Unproved properties	45		45
Exploration costs	858	15	873
Development costs	694	12	706
Costs expended	1,597	27	1,624
Asset retirement obligation costs	25		25
Total costs incurred	$ 1,622	$ 27	$ 1,649
2011 Unconsolidated Affiliate Four Star[(2)]:			
Development costs expended	$ 12	$	$ 12
2010 Consolidated:			
Property acquisition costs			
Proved properties	$ 51	$	$ 51
Unproved properties	269		269
Exploration costs	600	58	658
Development costs	276	28	304
Costs expended	1,196	86	1,282
Asset retirement obligation costs	7		7
Total costs incurred	$ 1,203	$ 86	$ 1,289
2010 Unconsolidated Affiliate Four Star[(2)]:			
Development costs expended	$ 20	$	$ 20
2009 Consolidated:			
Property acquisition costs			
Proved properties	$ 87	$	$ 87
Unproved properties	89	51	140
Exploration costs	355	67	422
Development costs	324	118	442
Costs expended	855	236	1,091
Asset retirement obligation costs	36	6	42
Total costs incurred	$ 891	$ 242	$ 1,133
2009 Unconsolidated Affiliate Four Star[(2)]:			
Development costs expended	$ 10	$	$ 10

(1) Costs incurred for Egypt were $8 million, $20 million and $81 million for the years ended December 31, 2011, 2010 and 2009.

(2) Amounts represent our approximate 49 percent equity interest in the underlying costs incurred by Four Star.

Pursuant to the full cost method of accounting, we capitalize certain general and administrative expenses directly related to property acquisition, exploration and development activities and interest costs incurred and attributable to unproved oil and natural gas properties and major development projects of oil and natural gas properties. The table above includes capitalized internal general and administrative costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves of $81 million for each of the years ended December 31, 2011 and 2010 and $80 million for the year ended December 31, 2009. We also capitalized interest of $13 million, $9 million and $7 million for the years ended December 31, 2011, 2010 and 2009.

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In our December 31, 2011 reserve report, the amounts estimated to be spent in 2012, 2013 and 2014 to develop our consolidated worldwide proved undeveloped reserves are $1,003 million, $1,009 million and $1,329 million, respectively.

Unevaluated Capitalized Costs. We exclude capitalized costs of oil and natural gas properties from amortization that are in various stages of evaluation or are part of a major development project. We expect these costs to be included in the amortization calculation in the next three to five years.

Presented below is an analysis of the capitalized costs of oil and natural gas properties by year of expenditure that are not being amortized as of December 31, 2011 pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2011	Costs Excluded for Years Ended December 31[1] 2011	2010	2009	Cumulative Balance January 1, 2009
U.S.					
Acquisition	$ 301	$ 20	$ 206	$ 29	$ 46
Exploration	98	80	4	10	4
Total U.S.[2]	399	100	210	39	50
Egypt & Brazil					
Acquisition	36	1		32	3
Exploration	46	8	20	10	8
Total Egypt & Brazil[3]	82	9	20	42	11
Worldwide	$ 481	$ 109	$ 230	$ 81	$ 61

(1) Includes capitalized interest of $2 million, $6 million and $2 million for the years ended December 31, 2011, 2010 and 2009.
(2) Includes $155 million related to the Wolfcamp Shale and $94 million related to the Eagle Ford Shale at December 31, 2011.
(3) Includes $8 million related to Brazil at December 31, 2011.

During 2011 we were informed that our environmental permit request for the Pinauna Field in the Camamu Basin was denied. As a result, we released $94 million of unevaluated capitalized costs related to this field into the Brazilian full cost pool. Additionally, during 2011, we released approximately $86 million of unevaluated capitalized costs into the Brazilian full cost pool related to the Espirito Santo Basin upon the completion of our evaluation of exploratory wells drilled in 2009 and 2010 without any additions to our proved reserves. We will continue to pursue alternatives for the hydrocarbons discovered in these areas. See Note 3 for further discussion.

Oil and Natural Gas Reserves. Net quantities of proved developed and undeveloped reserves of natural gas, oil and condensate and NGL and changes in these reserves at December 31, 2011 presented in the tables below are based on our internal reserve report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate. Our 2010 consolidated proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2011 except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), conducted an audit of the estimates of the proved reserves prepared by us as of December 31, 2011. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our proved reserves on a natural gas equivalent basis, representing 87 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, 2011. In connection with the audit of these proved reserves, Ryder Scott reviewed 87 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 91 percent of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10 percent of Ryder Scott s estimates. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

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	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	(in Bcfe)
Consolidated:								
January 1, 2009	2,091	47	2,138	23,910	3,180	27,090	4,159	2,325
Revisions due to prices	(138)	(2)	(140)	13,336	(380)	12,956	(3,552)	(84)
Revisions other than price	(36)	(6)	(42)	3,477	(640)	2,837	1,511	(16)
Extensions and discoveries(1)	380	70	450	18,089	2,136	20,225	16	572
Purchases of reserves in place(1)	19		19	7,343		7,343		63
Sales of reserves in place(1)	(49)		(49)	(1,328)		(1,328)	(260)	(59)
Production	(215)	(4)	(219)	(3,978)	(100)	(4,078)	(1,570)	(252)
December 31, 2009	2,052	105	2,157	60,849	4,196	65,045	304	2,549
Revisions due to prices	108	3	111	8,719	88	8,807	105	164
Revisions other than price	(58)	(13)	(71)	7,873	(1,246)	6,627	6,977	11
Extensions and discoveries(2)	506		506	28,141		28,141	3,088	693
Purchases of reserves in place(2)	25		25	3,045		3,045		43
Sales of reserves in place(2)	(21)		(21)	(1,024)		(1,024)		(27)
Production	(216)	(10)	(226)	(4,363)	(384)	(4,747)	(1,423)	(263)
December 31, 2010	2,396	85	2,481	103,240	2,654	105,894	9,051	3,170
Revisions due to prices	(9)		(9)	713	3	716		(5)
Revisions other than price	44	6	50	(1,630)	(34)	(1,664)	(1,124)	34
Extensions and discoveries(3)	519		519	90,128		90,128	7,525	1,105
Purchases of reserves in place(3)				13		13		
Sales of reserves in place(3)	(153)		(153)	(8,983)		(8,983)	(139)	(207)
Production	(231)	(10)	(241)	(5,680)	(354)	(6,034)	(1,068)	(284)
December 31, 2011	2,566	81	2,647	177,801	2,269	180,070	14,245	3,813

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	(in Bcfe)
Unconsolidated Affiliate Four Star:								
January 1, 2009	176		176	2,199		2,199	5,518	222
Revisions due to prices	(9)		(9)	23		23	(40)	(9)
Revisions other than price	10		10	100		100	456	13
Extensions and discoveries	1		1	4		4	8	1
Production	(20)		(20)	(419)		(419)	(678)	(26)
December 31, 2009	158		158	1,907		1,907	5,264	201
Revisions due to prices	8		8	44		44	87	9
Revisions other than price	6		6	36		36	(325)	4
Extensions and discoveries							5	
Production	(17)		(17)	(364)		(364)	(573)	(22)
December 31, 2010	155		155	1,623		1,623	4,458	192

Revisions due to prices	(5)		(5)	31		31	(28)	(5)
Revisions other than price	2		2	221		221	1,034	9
Extensions and discoveries								
Production	(17)		(17)	(306)		(306)	(556)	(22)
December 31, 2011	135		135	1,569		1,569	4,908	174
Total Combined:								
December 31, 2009	2,210	105	2,315	62,756	4,196	66,952	5,568	2,750
December 31, 2010	2,551	85	2,636	104,863	2,654	107,517	13,509	3,362
December 31, 2011	2,701	81	2,782	179,370	2,269	181,639	19,153	3,987
Consolidated:								
Proved developed reserves:								
January 1, 2011	1,559	75	1,634	38,278	2,403	40,681	6,096	1,914
December 31, 2011	1,488	81	1,569	46,797	2,269	49,066	5,168	1,895
Proved undeveloped reserves:								
January 1, 2011	837	10	847	64,962	251	65,213	2,955	1,256
December 31, 2011	1,078		1,078	131,004		131,004	9,077	1,918

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes
	U.S.	**Brazil**	**Worldwide**	**U.S.**	**Brazil**	**Worldwide**	**U.S.**	**(in Bcfe)**
Unconsolidated Affiliate Four Star:								
Proved developed reserves:								
January 1, 2011	129		129	1,574		1,574	3,483	159
December 31, 2011	116		116	1,520		1,520	4,066	150
Proved undeveloped reserves:								
January 1, 2011	26		26	49		49	975	32
December 31, 2011	19		19	49		49	842	24
Total Combined:								
Proved developed reserves:								
January 1, 2011	1,688	75	1,763	39,852	2,403	42,255	9,579	2,074
December 31, 2011	1,604	81	1,685	48,317	2,269	50,586	9,234	2,045
Proved undeveloped reserves:								
January 1, 2011	863	10	873	65,011	251	65,262	3,930	1,288
December 31, 2011	1,097		1,097	131,053		131,053	9,919	1,942

(1) In 2009, of the 572 Bcfe of extensions and discoveries, 301 Bcfe related to the Central division, of which, 208 Bcfe related to the Haynesville Shale and 70 Bcfe related to the Holly/Kingston fields. We also had 147 Bcfe of extensions and discoveries related to Altamont in the Western division and 83 Bcfe related to the Camarupim Field in Brazil. In addition, 41 Bcfe of extensions and discoveries related to the Gulf Coast division, of which, 14 Bcfe related to Eugene Island 364/365 in the Gulf of Mexico and 12 Bcfe related to the Wilcox area in South Texas. In 2009, we acquired interests in domestic oil and natural gas producing properties located in the Western division. We also sold domestic natural gas producing properties located in the Central and Western divisions.

(2) In 2010, of the 693 Bcfe of extensions and discoveries, 452 Bcfe related to the Central division, of which, 425 Bcfe related to the Haynesville Shale area. There were 238 Bcfe of extensions and discoveries in the Gulf Coast division with 187 Bcfe of that coming from the Eagle Ford Shale. The Western division accounted for 3 Bcfe of extensions and discoveries and there were no extensions and discoveries in the International division.

(3) In 2011, of the 1,105 Bcfe of extensions and discoveries, 428 Bcfe related to the Central division, of which, 389 Bcfe related to the Haynesville Shale area. There were 592 Bcfe of extensions and discoveries in the Southern division with 479 Bcfe of that coming from the Eagle Ford Shale and 113 coming from the Wolfcamp Shale. The Western division accounted for 85 Bcfe of extensions and discoveries and there were no extensions and discoveries in the International division.

Beginning December 31, 2009, in accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The first day 12-month average U.S. price used to estimate our proved reserves at December 31, 2011 was $4.12 per MMBtu for natural gas and $96.19 per barrel of oil. The prices used for our International assets were contractually defined. The aggregate International price used to estimate our proved reserves at December 31, 2011 was $5.31 per MMBtu for natural gas and $109.29 per barrel of oil.

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. 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, as a result 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 oil and natural gas that are ultimately recovered. Estimating quantities of proved oil and natural gas 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 they are based upon economic factors, such as oil and natural gas prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the 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.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Subsequent to December 31, 2011, there have been no major discoveries or other events, favorable or otherwise, that may be considered to have caused a significant change in our estimated proved reserves at December 31, 2011. Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. A sustained period of low domestic natural gas prices will over time result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our proved reserves.

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Results of Operations. Results of operations for oil and natural gas producing activities by fiscal year were as follows at December 31 (in millions):

	U.S.	Brazil and Egypt	Worldwide
2011 Consolidated:			
Net Revenues[1]			
Sales to external customers	$ 837	$ 111	$ 948
Affiliated sales	634		634
Total	1,471	111	1,582
Cost of products and services	(91)	(5)	(96)
Production costs[2]	(245)	(53)	(298)
Ceiling test charges[3]		(152)	(152)
Depreciation, depletion and amortization[4]	(563)	(32)	(595)
	572	(131)	441
Income tax expense	(207)		(207)
Results of operations from producing activities	$ 365	$ (131)	$ 234
Depreciation, depletion and amortization ($/Mcfe)[4]	$ 2.08	$ 2.60	$ 2.10
2011 Unconsolidated Affiliate Four Star[5]:			
Net Revenues Sales to external customers[1]	$ 123	$	$ 123
Cost of products and services	(4)		(4)
Production costs[2]	(49)		(49)
Depreciation, depletion and amortization[6]	(27)		(27)
	43		43
Income tax expense	15		15
Results of operations from producing activities	$ 28	$	$ 28
Depreciation, depletion and amortization ($/Mcfe)[6]	$ 1.20	$	$ 1.20
2010 Consolidated:			
Net Revenues[1]			
Sales to external customers	$ 551	$ 86	$ 637
Affiliated sales	743		743
Total	1,294	86	1,380
Cost of products and services	(81)	(5)	(86)
Production costs[2]	(218)	(46)	(264)
Ceiling test charges[3]		(25)	(25)
Depreciation, depletion and amortization[4]	(432)	(28)	(460)
	563	(18)	545
Income tax expense	(204)		(204)
Results of operations from producing activities	$ 359	$ (18)	$ 341

Depreciation, depletion and amortization ($/Mcfe)[(4)]	$ 1.72	$ 2.33	$ 1.75
2010 Unconsolidated Affiliate Four Star[(5)]*:*			
Net Revenues Sales to external customers[(1)]	$ 119	$	$ 119
Cost of products and services	(4)		(4)
Production costs[(2)]	(36)		(36)
Depreciation, depletion and amortization[(6)]	(28)		(28)
Asset impairment	(4)		(4)
	47		47
Income tax expense	(17)		(17)
Results of operations from producing activities	$ 30	$	$ 30
Depreciation, depletion and amortization ($/Mcfe)[(6)]	$ 1.24	$	$ 1.24

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2009 Consolidated:			
Net Revenues[1]			
Sales to external customers	$ 534	$ 25	$ 559
Affiliated sales	538		538
Total	1,072	25	1,097
Cost of products and services	(72)	(5)	(77)
Production costs[2]	(226)	(26)	(252)
Ceiling test charges[3]	(2,031)	(92)	(2,123)
Depreciation, depletion and amortization[4]	(415)	(9)	(424)
	(1,672)	(107)	(1,779)
Income tax benefit	605		605
Results of operations from producing activities	$ (1,067)	$ (107)	$ (1,174)
Depreciation, depletion and amortization ($/Mcfe)[4]	$ 1.67	$ 2.13	$ 1.68
2009 Unconsolidated Affiliate Four Star[5]:			
Net Revenues Sales to external customers[1]	$ 100	$	$ 100
Cost of products and services	(6)		(6)
Production costs[2]	(37)		(37)
Depreciation, depletion and amortization[6]	(29)		(29)
	28		28
Income tax expense	(10)		(10)
Results of operations from producing activities	$ 18	$	$ 18
Depreciation, depletion and amortization ($/Mcfe)[6]	$ 1.09	$	$ 1.09

(1) Excludes the effects of oil and natural gas derivative contracts.
(2) Production costs include lease operating costs and production related taxes, including ad valorem and severance taxes.
(3) Includes $152 million related to Brazil for the year ended December 31, 2011 and $25 million and $34 million related to Egypt for the years ended December 31, 2010 and 2009.
(4) Includes accretion expense on asset retirement obligations of $13 million or $0.05/Mcfe in 2011 and $16 million or $0.06/Mcfe in 2010 and 2009, respectively.
(5) Results do not include amortization of $34 million, $38 million and $48 million for the years ended December 31, 2011, 2010 and 2009 related to cost in excess of our equity interest in the underlying net assets of Four Star.
(6) Includes accretion expense on asset retirement obligations of $2 million or $0.10/Mcfe in 2011, $1 million or $0.06/Mcfe in 2010 and $2 million or $0.06/Mcfe in 2009.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to our consolidated proved oil and natural gas reserves at December 31 is as follows (in millions):

	U.S.	Brazil	Worldwide
2011 Consolidated:			
Future cash inflows[1]	$ 26,079	$ 768	$ 26,847
Future production costs	(5,840)	(415)	(6,255)
Future development costs	(6,343)	(34)	(6,377)
Future income tax expenses	(4,086)	(23)	(4,109)

Future net cash flows	9,810	296	10,106
10% annual discount for estimated timing of cash flows	(4,793)	(97)	(4,890)
Standardized measure of discounted future net cash flows	$ 5,017	$ 199	$ 5,216
2011 Unconsolidated Affiliate Four Star[2]:			
Future cash inflows[1]	$ 938	$	$ 938
Future production costs	(348)		(348)
Future development costs	(66)		(66)
Future income tax expenses	(201)		(201)
Future net cash flows	323		323
10% annual discount for estimated timing of cash flows	(129)		(129)
Standardized measure of discounted future net cash flows	$ 194	$	$ 194
2010 Consolidated:			
Future cash inflows[1]	$ 17,145	$ 659	$ 17,804
Future production costs	(4,768)	(325)	(5,093)
Future development costs	(3,249)	(67)	(3,316)
Future income tax expenses	(2,403)	(9)	(2,412)
Future net cash flows	6,725	258	6,983
10% annual discount for estimated timing of cash flows	(2,905)	(77)	(2,982)
Standardized measure of discounted future net cash flows	$ 3,820	$ 181	$ 4,001

2010 Unconsolidated Affiliate Four Star[2]:			
Future cash inflows[1]	$ 943	$	$ 943
Future production costs	(404)		(404)
Future development costs	(34)		(34)
Future income tax expenses	(192)		(192)
Future net cash flows	313		313
10% annual discount for estimated timing of cash flows	(131)		(131)
Standardized measure of discounted future net cash flows	$ 182	$	$ 182
2009 Consolidated:			
Future cash inflows[1]	$ 10,058	$ 714	$ 10,772
Future production costs	(3,531)	(339)	(3,870)
Future development costs	(1,698)	(108)	(1,806)
Future income tax expenses	(511)	(17)	(528)
Future net cash flows	4,318	250	4,568
10% annual discount for estimated timing of cash flows	(1,744)	(82)	(1,826)
Standardized measure of discounted future net cash flows	$ 2,574	$ 168	$ 2,742
2009 Unconsolidated Affiliate Four Star[2]:			
Future cash inflows[1]	$ 855	$	$ 855
Future production costs	(394)		(394)
Future development costs	(32)		(32)
Future income tax expenses	(157)		(157)
Future net cash flows	272		272
10% annual discount for estimated timing of cash flows	(110)		(110)
Standardized measure of discounted future net cash flows	$ 162	$	$ 162

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2011, 2010 and 2009. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves as of December 31, 2011 were computed using a first day 12-month average U.S. price of $4.12 per MMBtu for natural gas and $96.19 per barrel of oil. The aggregate international price used to estimate our proved reserves at December 31, 2011 was $5.31 per MMBtu for natural gas and $109.29 per barrel of oil.

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in our consolidated worldwide standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,[1]		
	2011	**2010**	**2009**
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$ (1,200)	$ (1,042)	$ (779)
Net changes in prices and production costs	1,057	1,734	(1,455)
Extensions, discoveries and improved recovery, less related costs	2,140	986	646
Changes in estimated future development costs	(415)	(226)	45

Previously estimated development costs incurred during the period	601	199	186
Revision of previous quantity estimates	49	315	(94)
Accretion of discount	430	220	310
Net change in income taxes	(599)	(934)	246
Purchases of reserves in place		73	121
Sales of reserves in place	(587)	(47)	(79)
Change in production rates, timing and other	(261)	(19)	199
Net change	$ 1,215	$ 1,259	$ (654)
Unconsolidated Affiliate Four Star:			
Sales and transfers of oil and natural gas produced net of production costs	$ (74)	$ (83)	$ (137)
Net changes in prices and production costs	62	70	(351)
Extensions, discoveries and improved recovery, less related costs		1	1
Changes in estimated future development costs	(14)	(1)	22
Revision of previous quantity estimates	6	16	5
Accretion of discount	22	18	57
Net change in income taxes	(9)	(16)	137
Change in production rates, timing and other	19	15	32
Net change	$ 12	$ 20	$ (234)

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

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SCHEDULE VALUATION AND QUALIFYING ACCOUNTS

SCHEDULE II

EL PASO CORPORATION

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2011, 2010 and 2009

(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2011					
Allowance for doubtful accounts	$ 4	$	$	$ (2)	$ 2
Valuation allowance on deferred tax assets	391	21[(1)]			412
Legal reserves	45	7	(14)		38
Environmental reserves	173	44	(36)		181
Regulatory reserves[(2)]	19			91	110
2010					
Allowance for doubtful accounts	$ 8	$	$	$ (4)	$ 4
Valuation allowance on deferred tax assets	384	7[(1)]			391
Legal reserves	66	14	(34)	(1)	45
Environmental reserves	189	26	(42)		173
Regulatory reserves[(2)]	74		(76)	21	19
2009					
Allowance for doubtful accounts	$ 9	$	$	$ (1)	$ 8
Valuation allowance on deferred tax assets	337	47[(1)]			384
Legal reserves	73	20	(27)		66
Environmental reserves	204	25	(40)		189
Regulatory reserves[(2)]				74	74

(1) Amounts reflect valuation allowances primarily associated with foreign and state net operating losses and foreign ceiling test charges.
(2) Reflects rate refund and settlement activity.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2011, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2011. See Item 8, Financial Statements and Supplementary Data under Management s Annual Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2011 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our definitive proxy statement for the 2012 Annual Meeting of Stockholders or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our definitive proxy statement for the 2012 Annual Meeting of Stockholders or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

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

The information required by this item is incorporated by reference from our definitive proxy statement for the 2012 Annual Meeting of Stockholders or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

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

The information required by this item is incorporated by reference from our definitive proxy statement for the 2012 Annual Meeting of Stockholders or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our definitive proxy statement for the 2012 Annual Meeting of Stockholders or, in the event we do not prepare and file such proxy statement, such information shall be filed as an amendment to this Form 10-K. Such information shall be filed no later than April 30, 2012.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial statements.

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

2. Financial statement schedules and supplementary information required to be submitted

Schedule II Valuation and Qualifying Accounts

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

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

(c) Financial Statements of 50-Percent-Or-Less-Owned Investees:

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Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4) (iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of stockholders equity and of cash flows present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the Company) at December 31, 2011 and December 31, 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 24, 2012

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CITRUS CORP. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 22,746	$ 39,018
Accounts receivable, billed and unbilled, less allowances of $17 and $17, respectively	64,421	49,985
Income tax asset (Note 10)	84,889	
Deferred tax asset (Note 10)	58,056	
Materials and supplies	19,278	14,737
Other	11,140	3,368
Total current assets	260,530	107,108
Property, plant and equipment (Note 11)		
Plant in service	7,510,640	4,854,917
Construction work in progress	48,447	2,217,174
	7,559,087	7,072,091
Less accumulated depreciation and amortization	1,799,172	1,667,360
Net property, plant and equipment	5,759,915	5,404,731
Other assets		
Unamortized debt expense	16,249	19,070
Regulatory assets (Note 12)	32,729	21,725
Other	5,737	8,057
Total other assets	54,715	48,852
Total assets	$ 6,075,160	$ 5,560,691
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current portion of long-term debt - notes	$ 271,480	$ 21,500
Current portion of long-term debt - revolvers	415,000	
Accounts payable - trade and other	38,915	31,703
Accounts payable - affiliates	11,219	11,260
Accrued interest	45,410	45,637
Capital accruals	28,354	133,002
Provision for rate refunds (Note 4)		30,837
Other	37,127	43,013
Total current liabilities	847,505	316,952
Deferred credits		
Accumulated deferred income taxes, net (Note 10)	1,152,727	895,279
Regulatory liabilities (Note 13)	12,822	9,363
Other (Note 13)	17,872	16,558

Total deferred credits	1,183,421	921,200
Long-term debt (Note 8)	2,052,413	2,591,150
Stockholder promissory notes (Note 8)	74,000	
Commitments and contingencies (Note 14)		
Stockholders Equity		
Common stock, $1 par value; 1,000 shares authorized, issued and outstanding	1	1
Additional paid-in capital	834,271	834,271
Accumulated other comprehensive loss	(4,428)	(5,480)
Retained earnings	1,087,977	902,597
Total stockholders equity	1,917,821	1,731,389
Total liabilities and stockholders equity	$ 6,075,160	$ 5,560,691

The accompanying notes are an integral part of these consolidated financial statements.

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CITRUS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2011	2010	2009
	(In thousands)		
Operating revenues			
Transportation of natural gas (Note 4)	$ 693,626	$ 517,158	$ 508,416
Total operating revenues	693,626	517,158	508,416
Operating expenses			
Operations and maintenance	79,864	64,655	53,714
Operations and maintenance - affiliates (Note 5)	45,004	39,495	37,671
Depreciation and amortization	139,083	107,270	110,384
Taxes, other than on income	37,968	35,949	34,750
Total operating expenses	301,919	247,369	236,519
Operating income	391,707	269,789	271,897
Other income (expense)			
Interest expense and related charges, net	(156,213)	(116,417)	(118,806)
Other, net	60,744	139,920	55,021
Total other income (expense), net	(95,469)	23,503	(63,785)
Income before income taxes	296,238	293,292	208,112
Income taxes (Note 10)	110,858	112,365	78,429
Net income	$ 185,380	$ 180,927	$ 129,683

The accompanying notes are an integral part of these consolidated financial statements.

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CITRUS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Common stock			
Balance, beginning and end of period	$ 1	$ 1	$ 1
Additional paid-in capital			
Balance, beginning of period	834,271	634,271	634,271
Equity contributions (Note 5)		200,000	
Balance, end of period	834,271	834,271	634,271
Accumulated other comprehensive loss			
Balance, beginning of period	(5,480)	(8,248)	(5,246)
Net change in other comprehensive income (loss) (Note 7)	1,052	2,768	(3,002)
Balance, end of period	(4,428)	(5,480)	(8,248)
Retained earnings			
Balance, beginning of period	902,597	721,670	591,987
Net income	185,380	180,927	129,683
Balance, end of period	1,087,977	902,597	721,670
Total stockholders equity	$ 1,917,821	$ 1,731,389	$ 1,347,694

The accompanying notes are an integral part of these consolidated financial statements.

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CITRUS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Cash flows provided by (used in) operating activities			
Net income	$ 185,380	$ 180,927	$ 129,683
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	139,083	107,270	110,384
Deferred income taxes	196,738	60,602	36,216
Allowance for equity funds used during construction	(37,278)	(86,153)	(37,060)
Allowance for equity funds used during construction - tax gross up	(23,054)	(53,268)	(22,990)
Other	5,438	4,939	5,862
Changes in operating assets and liabilities:			
Accounts receivable	(14,436)	(8,983)	(694)
Accounts payable	7,171	(2,273)	2,992
Accrued provision for rate refunds	(30,837)	30,837	
Accrued interest	(226)	16,257	8,462
Accrued current taxes	(97,649)	1,104	14,150
Other current assets and liabilities	(4,349)	(4,238)	(1,301)
Other long-term assets and liabilities	(4,276)	(6,512)	3,938
Net cash flows provided by operating activities	321,705	240,509	249,642
Cash flows provided by (used in) investing activities			
Capital expenditures	(575,255)	(1,545,526)	(455,064)
Allowance for equity funds used during construction	37,278	86,153	37,060
Net cash flows used in investing activities	(537,977)	(1,459,373)	(418,004)
Cash flows provided by (used in) financing activities			
Issuance of long-term debt		850,000	600,000
Issuance costs of debt		(6,988)	(5,964)
Premium for redemption of debt		(6,519)	
Equity contribution		200,000	
Repayment of long-term debt obligations	(21,500)	(346,500)	(51,500)
Net change in revolving credit facilities	147,500	262,292	(79,375)
Interest rate hedge - settlement			(9,234)
Stockholder promissory notes			
Borrowings	144,000		
Payments	(70,000)		
Net cash flows provided by financing activities	200,000	952,285	453,927
Change in cash and cash equivalents	(16,272)	(266,579)	285,565
Cash and cash equivalents at beginning of period	39,018	305,597	20,032
Cash and cash equivalents at end of period	$ 22,746	$ 39,018	$ 305,597
Cash paid for interest, net of amounts capitalized	$ 168,363	$ 145,473	$ 118,569
Cash paid for income taxes, net of refunds	$ 3,505	$ 52,955	$ 36,311

The accompanying notes are an integral part of these consolidated financial statements.

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CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Corporate Structure

Citrus Corp. (*Citrus*), a holding company formed in 1986, owns 100 percent of the membership interest in Florida Gas Transmission Company, LLC (*Florida Gas*), and 100 percent of the stock of Citrus Energy Services, Inc. (*CESI*) (collectively, *the Company*). At December 31, 2011, the stock of Citrus was owned 50 percent by El Paso Citrus Holdings, Inc. (*EPCH*), a wholly-owned subsidiary of El Paso Corporation (*El Paso*), and 50 percent by CrossCountry Citrus, LLC (*CCC*), a wholly-owned subsidiary of CrossCountry Energy, LLC (*CrossCountry*) an indirect subsidiary of Southern Union Company (*Southern Union*).

Florida Gas, an open-access interstate natural gas pipeline extending from south Texas through the Gulf Coast region of the United States to south Florida, is engaged in the interstate transmission of natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (*FERC*). Florida Gas pipeline system primarily receives natural gas from producing basins along the Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico, and transports natural gas to the Florida market.

See *Note 3 Proposed Transfer of Southern Union s Equity Interest in Citrus and Related Litigation* for information related to Southern Union s intent to merge with Energy Transfer Equity, L.P. (*ETE*).

The Company evaluated subsequent events through February 24, 2012, the date on which these financial statements were issued.

2. Summary of Significant Accounting Policies and Other Matters

Basis of Presentation. The Company s consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America *(GAAP).*

Principles of Consolidation. The consolidated financial statements include the accounts of Citrus and its wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulatory Accounting. The Company is subject to regulation by certain state and federal authorities. The Company s accounting policies conform to authoritative guidance that is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. These accounting policies allow the Company to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the Consolidated Statement of Income by an unregulated company. These deferred assets and liabilities then flow through the results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Certain allowable regulatory deferrals of phase-in costs are prohibited under GAAP. As a consequence, certain phase-in costs of Florida Gas Phase III expansion are not deferred for GAAP-basis reporting but are deferred for future recovery for ratemaking purposes.

Management s assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheet and included in the Consolidated Statement of Income for the period in which the discontinuance of regulatory accounting treatment occurs. See *Note 12 Regulatory Assets* and *Note 13 Deferred Credits*.

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CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Property, Plant and Equipment.

Additions. Ongoing additions of property, plant and equipment are stated at cost. Florida Gas capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Such indirect construction costs primarily include labor and related costs of departments associated with supporting construction activities, which are largely based upon results of periodic time studies or management reviews of time allocations, which provide an estimate of time spent supporting construction projects. The cost of replacements and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs and replacements of minor property, plant and equipment items is charged to expense as incurred.

Retirements. When ordinary retirements of property, plant and equipment occur, the original cost less salvage value is removed by a charge to accumulated depreciation and amortization, with no gain or loss recorded. When entire regulated operating units of property, plant and equipment are retired or sold, the original cost less salvage value and related accumulated depreciation and amortization accounts are removed, with any resulting gain or loss recorded in earnings.

Depreciation. The Company amortized that portion of its investment in Florida Gas property which is in excess of historical cost (acquisition adjustment) on a straight-line basis at an annual composite rate of 1.6 percent based upon the estimated useful life of the pipeline system.

Florida Gas computed depreciation expense using the straight-line method at an annual composite rate of 2.21 percent, 2.57 percent and 2.78 percent for the years ended December 31, 2011, 2010 and 2009, respectively. The depreciation rates decreased effective April 1, 2010 based on the settlement of Florida Gas rate case; see *Note 4 Regulatory Matters* for additional information.

Allowance for Funds Used During Construction** (AFUDC)**. The recognition of AFUDC is a utility accounting practice with calculations under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant. It represents the cost of capital invested in construction work-in-progress. AFUDC has been segregated into two component parts borrowed funds and equity funds. The allowance for borrowed funds, which is included in the accompanying Statements of Income as a reduction in Interest expense, totaled $18.1 million, $50.5 million and $13.2 million for the years ended December 31, 2011, 2010 and 2009, respectively. The allowance for equity funds used during construction, including related amounts to gross up equity AFUDC to a before tax basis, totaled $60.3 million, $139.4 million and $60.1 million for the years ended December 31, 2011, 2010 and 2009, respectively. AFUDC equity funds are included in *Other income* in the accompanying Statements of Income.

Asset Impairment. An impairment loss is recognized when the carrying amount of a long-lived asset used in operations is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. A long-lived asset is tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable.

Cash and Cash Equivalents. Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts. The Company manages trade credit risks to minimize exposure to uncollectible trade receivables. Prospective and existing customers are reviewed for creditworthiness based upon pre-established standards. Customers that do not meet minimum standards are required to provide additional credit support. The Company considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Increases in the allowance are recorded as a component of operating expenses. Reductions in the allowance are recorded when receivables are written off or subsequently collected. Past due receivable balances are written-off when the Company s efforts have been unsuccessful in collecting the amount due. Unrecovered accounts receivable charged against the allowance for doubtful accounts were nil for each of the years ended December 31, 2011, 2010 and 2009, respectively.

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CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the relative contribution to the Company s total operating revenue of each customer that comprised at least ten percent of its operating revenues for the periods presented. Revenues from individual third party and affiliate customers exceeding 10 percent of total revenues were approximately 59 percent, 53 percent and 54 percent of total revenue for the years ended December 31, 2011, 2010 and 2009, respectively.

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
NextEra Energy, Inc.[1]	$ 320,312	$ 209,385	$ 199,217
TECO Energy	88,343	79,228	73,430

The Company had the following transportation receivables from these customers at the dates indicated:

	December 31,	
	2011	2010
	(In thousands)	
NextEra Energy, Inc.[1]	$ 29,060	$ 16,881
TECO Energy	7,070	5,969

(1) Formerly referred to as Florida Power & Light Company

The Company has a concentration of customers in the electric and natural gas utility industries. These concentrations of customers may impact the Company s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. Credit losses incurred on receivables in these industries compare favorably to losses experienced in the Company s receivable portfolio as a whole. The Company also has a concentration of customers located in the southeastern United States, primarily within the state of Florida. Receivables are generally not collateralized. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments, deposits, or other forms of security to the Company. Florida Gas sought additional assurances from customers due to credit concerns, and had customer deposits totaling $1.5 million and $1.5 million, and prepayments of $49,000 and $62,000 at December 31, 2011 and 2010, respectively. The Company s management believes that the portfolio of Florida Gas receivables, which includes regulated electric utilities, regulated local distribution companies, and municipalities, is of minimal credit risk.

Materials and Supplies. Materials and supplies are stated at the lower of weighted average cost or market value. Materials transferred out of warehouses are priced at weighted average cost. Materials and supplies include spare parts which are critical to the pipeline system operations.

Natural Gas Imbalances. Natural gas imbalances occur as a result of differences in volumes of natural gas received and delivered. These imbalances due to or from shippers and operators are valued at an appropriate index price. Natural gas imbalances are settled in cash or made up in-kind subject to the terms of Florida Gas tariff, and generally do not impact earnings.

Fuel Tracker. The fuel tracker is the cumulative balance owed to Florida Gas by its customers or owed by Florida Gas to its customers for gas used in the operation of its system, including costs incurred in the operation of electric compression and gas lost from the system or otherwise unaccounted for. The customers, pursuant to Florida Gas tariff and related contracts, provide fuel to Florida Gas based on specified percentages of the customers natural gas volumes delivered into the pipeline. The percentages are designed to match the actual fuel consumed in moving the natural gas through Florida Gas facilities, with any difference between the volumes provided versus fuel consumed reflected in the fuel tracker. A regulatory liability is recorded in the accompanying Consolidated Balance Sheets for net volumes of natural gas owed to customers collectively. Whenever fuel is due from customers from prior under recovery based on contractual and specific tariff provisions a regulatory asset is recorded. Natural gas owed from or to customers is valued at market and a surcharge is invoiced to recover or refund the previous under or over collections. Changes in the balances have no effect on the net income of Florida Gas.

CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unamortized Debt Premium, Discount and Expense. The Company amortizes premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

Environmental Expenditures. Environmental expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Environmental expenditures relating to current or future revenues are expensed or capitalized as appropriate. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Remediation obligations are not discounted because the timing of future cash flow streams is not predictable.

See *Note 14 Commitments and Contingencies*.

Revenues. Revenues from transportation of natural gas are based on capacity reservation charges and commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and are recognized monthly. Revenues from commodity usage charges are also recognized monthly, based on the volumes of natural gas delivered.

Because Florida Gas is subject to FERC regulations, revenues collected during the pendency of a rate proceeding may be required by the FERC to be refunded in the final order. Florida Gas establishes reserves for such potential refunds, as appropriate. There was nil and $30.8 million for potential rate refunds at December 31, 2011 and 2010, respectively. See *Note 4 Regulatory Matters*.

Accumulated Other Comprehensive Loss. The main components of comprehensive income (loss) that relate to the Company are net earnings and unrealized gain (loss) on hedging activities. For more information, see *Note 7 Comprehensive Income.*

Fair Value Measurement. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk, which is primarily comprised of credit risk (both the Company s own credit risk and counterparty credit risk) and the risks inherent in the inputs to any applicable valuation techniques. The Company places more weight on current market information concerning credit risk (e.g. current credit default swap rates) as opposed to historical information (e.g. historical default probabilities and credit ratings). These inputs can be readily observable, market corroborated, or generally unobservable. The Company endeavors to utilize the best available information, including valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. A three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value, is as follows:

Level 1 Observable inputs such as quoted prices in active markets for identical assets or liabilities;

Level 2 Observable inputs such as: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active and do not require significant adjustment based on unobservable inputs; or (iii) valuations based on pricing models, discounted cash flow methodologies or similar techniques where significant inputs (e.g., interest rates, yield curves, etc.) are derived principally from observable market data, or can be corroborated by observable market data, for substantially the full term of the assets or liabilities; and

Level 3 Unobservable inputs, including valuations based on pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Unobservable inputs are used to the extent that observable inputs are not available and reflect the Company s own assumptions about the assumptions market participants would use in pricing the assets or liabilities. Unobservable inputs are based on the best information available in the circumstances, which might include the Company s own data.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy.

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CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

See *Note 9 Benefits Postretirement Benefit Plans Plan Assets* for additional information regarding the assets of the Company measured on a non-recurring basis.

Derivatives and Hedging Activities. All derivatives are recognized on the Consolidated Balance Sheets at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (*a fair value hedge*); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (*a cash flow hedge*); or (iii) an instrument that is held for trading or non-hedging purposes (*a trading or economic hedging instrument).* For derivatives treated as a fair value hedge, the effective portion of changes in fair value is recorded as an adjustment to the hedged item. The ineffective portion of a fair value hedge is recognized in earnings if the short cut method of assessing effectiveness is not used. Upon termination of a fair value hedge of a debt instrument, the resulting gain or loss is amortized to earnings through the maturity date of the debt instrument. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in *Accumulated other comprehensive loss* until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings. Upon termination of a cash flow hedge, the resulting gain or loss is amortized to earnings through the maturity date of the hedged forecasted transactions. For derivatives treated as trading or economic hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and pricing models using assumptions that market participants would use. As of December 31, 2011 and 2010, the Company does not have any hedges in place; it is only amortizing previously terminated cash flow hedges.

Asset Retirement Obligations *(AROs).* Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Company did not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium could not be reliably estimated. Upon initial recognition of the liability, costs are capitalized as part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. To the extent the Company is permitted to collect and has reflected in its financials amounts previously collected from customers and expensed, such amounts serve to reduce what would be reflected as capitalized costs at the initial establishment of an ARO. The Company records ARO accretion and amortization expenses (in excess of current recoveries) as a regulatory asset based on the probability of recovery in rates in future rate cases.

For more information, see *Note 6 Asset Retirement Obligations*.

Income Taxes. Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the Company s provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. Reserves are established when, despite management s belief that the Company s tax return positions are fully supportable, management believes that certain positions may be successfully challenged. When facts and circumstances change, these reserves are adjusted through the provision for income taxes. See *Note 10 Taxes on Income*.

Retirement Plans. Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the accumulated postretirement benefit obligation. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through Accumulated other comprehensive loss in stockholders equity.

CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company recognized net periodic benefit expense to the extent of amounts recorded in rates with any difference recorded as a regulatory asset or liability. Unrecognized prior service costs (benefits) and gains and/or losses are not recorded as a change to *Accumulated other comprehensive loss*, but rather as a regulatory asset or regulatory liability, reflecting amounts due from or to customers, respectively. See *Note 9 Benefits* for additional related information.

New Accounting Principles

Accounting Principles Not Yet Adopted. In December 2011, the Financial Accounting Standards Board (*FASB*) issued authoritative guidance that enhances current disclosures about offsetting asset and liabilities. The guidance requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The guidance is effective for annual and interim reporting periods beginning on or after January 1, 2013. The Company does not expect the guidance to materially impact its consolidated financial statements.

In June 2011, the FASB issued authoritative guidance that changes how a company may present comprehensive income. The guidance allows entities to elect to present items of net income and other comprehensive income in one continuous statement or in two separate, but consecutive statements and eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. The entity is also required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the components of net income and the components of other comprehensive income are presented. The guidance is effective as of the beginning of a fiscal year that begins after December 15, 2011 and interim and annual periods thereafter, with early adoption permitted. In December 2011, the FASB issued authoritative guidance that defers the presentation requirements for reclassification adjustments to allow the FASB time to redeliberate these requirements. The Company does not expect the guidance to materially impact its consolidated financial statements as the guidance only requires a change in the placement of previously disclosed information.

In May 2011, the FASB issued authoritative guidance on fair value measurements that clarifies some existing concepts, eliminates wording differences between GAAP and International Financial Reporting Standards (*IFRS*), and in some limited cases, changes some principles to achieve convergence between GAAP and IFRS. The guidance provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS and also expands the disclosures for fair value measurements that are estimated using significant unobservable (Level 3) inputs. The guidance is effective for periods beginning after December 15, 2011. The Company is currently evaluating the impact of this guidance, but does not expect it will materially impact its consolidated financial statements.

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CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. Proposed Transfer of Southern Union s Equity Interest in Citrus and Related Litigation

On July 19, 2011, Southern Union entered into a Second Amended and Restated Agreement and Plan of Merger with ETE and Sigma Acquisition Corporation, a wholly-owned subsidiary of ETE (*Merger Sub*) (as amended by Amendment No. 1 thereto dated as of September 14, 2011, the *Second Amended Merger Agreement*). The Second Amended Merger Agreement modifies certain terms of the Agreement and Plan of Merger entered into by Southern Union, ETE and Merger Sub on June 15, 2011 as amended on July 4, 2011. The Second Amended Merger Agreement provides for the merger of Merger Sub with and into Southern Union (*Merger*), with Southern Union continuing as the surviving corporation in the Merger. As a result of the Merger, Southern Union will become a wholly-owned subsidiary of ETE.

In addition, ETE and Energy Transfer Partners, L.P., a wholly-owned subsidiary of ETE (*ETP*), are parties to an Amended and Restated Agreement and Plan of Merger dated as of July 19, 2011 (as amended by Amendment No. 1 thereto dated as of September 14, 2011) (*Citrus Merger Agreement*). The Citrus Merger Agreement provides that Southern Union, CrossCountry, PEPL Holdings, LLC, a wholly-owned subsidiary of CCE Acquisition, LLC, which is a wholly-owned subsidiary of Southern Union, and Citrus ETP Acquisition, L.L.C. (*Citrus ETP*), a wholly-owned subsidiary of ETP, will become parties by joinder at a time immediately prior to the closing of the Merger. Upon becoming a party to the Citrus Merger Agreement, Southern Union will assume the obligations and rights of ETE. Under the Citrus Merger Agreement, CrossCountry will be merged with and into Citrus ETP with CrossCountry surviving as a wholly-owned subsidiary of ETP (*Citrus Merger*).

The Merger received stockholder approval on December 9, 2011. On February 16, 2012, the parties filed with the Missouri Public Service Commission (*MPSC*) a Non-Unanimous Stipulation and Agreement (the *Stipulation*) among Southern Union, ETE and the MPSC Staff. Pursuant to the Stipulation, the parties recommend that the MPSC issue an order finding that, subject to the conditions therein, the merger of Merger Sub with and into Southern Union is not detrimental to the public interest and authorizing the undertaking of the Merger and related transactions. The Office of Public Counsel has indicated that it does not oppose the Stipulation. Southern Union and ETE have requested that the MPSC consider the Stipulation expeditiously. The Merger is expected to close in the first quarter of 2012, subject to receipt of MPSC approval and satisfaction of other closing conditions.

CrossCountry, a Principal under the Citrus Corp. Capital Stock Agreement (*CSA*), filed a complaint in the Delaware Court of Chancery against EPCH and its parent El Paso seeking a declaratory judgment that the Citrus Merger does not, as El Paso contends, trigger any provisions of the CSA which would require Southern Union to provide El Paso a right of first refusal concerning Citrus. The complaint was filed by CrossCountry following an exchange of letters between El Paso and Southern Union regarding the terms of the CSA. Following the filing of the declaratory judgment action, El Paso filed a third-party complaint against Southern Union, ETE, and ETP alleging, among other things, breach of the CSA. El Paso is not currently seeking to enjoin the closing of the Citrus Merger, but rather seeks a rescission of the Citrus Merger after it is completed or, alternatively, damages. Trial is currently set for April 2012.

As described in the preceding paragraph, El Paso and CrossCountry are parties to a litigation regarding the effect of certain planned transactions on their respective ownership interests in the Company. Recently, management of the Company determined not to provide the Company s independent auditors with updated written management representations regarding the Company s previously issued financial statements in connection with the independent auditor s response to a request to consent to the incorporation by reference of its audit report on those previously issued financial statements in a registration statement filing of a third party. Although a management representation letter has been provided in connection with this issuance of the Company s accompanying financial statements, if management were to determine not to provide updating written management representations in connection with a future issuance of the independent auditor s consent or a request to consent to the incorporation by reference of the independent auditor s audit report on the Company s financial statements into a filing of the Company or its owners, such determination would limit the Company s ability to comply with its reporting requirements, if any, or undertake certain transactions and could, under certain circumstances, limit the ability of an owner of the Company to comply with its reporting requirements or undertake certain transactions.

4. Regulatory Matters

On March 24, 2011, FERC authorized the Phase VIII Expansion project to go in service. Florida Gas placed the project in service on April 1, 2011, with total project costs of approximately $2.5 billion, including capitalized equity and debt costs. To date, Florida Gas has entered into long-term firm transportation service agreements with shippers for 25-year terms accounting for approximately 74 percent of the available expansion capacity.

On September 3, 2010, Florida Gas filed a settlement with FERC in full resolution of all issues set for hearing in its rate proceeding. The Administrative Law Judge certified the settlement on December 21, 2010. The settlement was approved by FERC on February 24, 2011 and became effective on April 1, 2011. The settlement results in an increase in certain of Florida Gas rate schedules and a decrease in other rate schedules as compared to rates in effect prior to April 1, 2010, with a portion of such decrease not effective until October 1, 2010. On May 27, 2011, Florida Gas refunded $43.9 million to its customers for excess payments collected for service through March 31, 2011, including interest of $0.8 million.

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5. Affiliate Transactions

The following table provides a summary of affiliate transactions for the periods presented.

	Twelve months ended December 31, 2011	2010	2009
		(In thousands)	
Operation and maintenance:			
Transporation service charges[1]	$ 8,449	$ 8,164	$ 7,092
Corporate service charges[2]	11,667	8,919	7,493
Operational and administrative service charges[3]	24,888	22,412	23,086

(1) Represents transportation services purchased from Southern Natural Gas Company (*Southern*), a subsidiary of El Paso, in connection with its Phase III Expansion completed in early 1995. Florida Gas is currently contracted for firm capacity of 100,000 Mcf/d on Southern s system through August 31, 2013.

(2) Primarily includes corporate service charges from Southern Union.

(3) Primarily includes activities for operational and administrative services performed by Panhandle Eastern Pipe Line Company, LP, an indirect wholly-owned subsidiary of Southern Union, and its subsidiaries on behalf of the Company.

At December 31, 2011 and 2010, the Company had current net accounts payable to affiliated companies of $11.2 million and $11.3 million, respectively, relating to these services.

The Company did not pay cash dividends to its stockholders during the years ended December 31, 2011, 2010 and 2009 primarily due to the ongoing Phase VIII Expansion capital requirements. The Company received sponsor capital contributions from its stockholders of $200 million during the year ended December 31, 2010. In 2011, the Company received sponsor contributions of $74 million from its stockholders in the form of loans, net of repayments. See *Note 8 Debt Obligations* for additional information regarding the loans.

6. Asset Retirement Obligations

The Company s recorded AROs are primarily related to owned offshore lines. At the end of the useful life of these underlying assets, the Company is legally or contractually required to abandon in place or remove the asset. An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. Although a number of other assets in the Company s system are subject to agreements or regulations that give rise to an ARO upon the Company s discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement.

Individual component assets have been and will continue to be replaced, but the pipeline system will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. The Company has in place a rigorous repair and maintenance program that keeps the pipeline system in good working order. Therefore, although some of the individual assets on the pipeline system may be replaced, the pipeline system itself will remain intact indefinitely.

The following table is a general description of AROs and associated long-lived assets at December 31, 2011.

ARO Description	In Service Date	Long-Lived Assets	Amount (In thousands)
Retire lateral lines	Various	Offshore lateral lines	$ 802
Remove asbestos	Various	Mainlines and compressors	$ 489

As of December 31, 2011, the Company has $260,000 in legally restricted funds reflected in *Other assets* on the Consolidated Balance Sheet for the purpose of settling AROs. The Company also has AROs totaling $290,000 reflected in *Other current liabilities* on the Consolidated Balance Sheets that are expected to be settled in 2012.

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The following table is a reconciliation of the carrying amount of the ARO liability for the periods presented. Changes in assumptions regarding the timing, amount, and probabilities associated with the expected cash flows, as well as the difference in actual versus estimated costs, will result in a change in the amount of the liability recognized.

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Beginning balance	$ 3,003	$ 2,585	$ 1,819
Incurred		283	2,064
Revisions	(434)		
Settled	(41)	(40)	(1,450)
Accretion expense	189	175	152
Ending balance	$ 2,717	$ 3,003	$ 2,585

7. Comprehensive Income (Loss)

Deferred gains and losses in connection with the termination of the following derivative instruments which were previously accounted for as cash flow hedges form part of other comprehensive income. Such amounts are being amortized over the terms of the hedged debt. As of December 31, 2011, approximately $0.5 million of net after-tax losses in *Accumulated other comprehensive loss* related to these interest rate hedges is expected to be amortized into *Interest expense* during the next twelve months.

The table below provides a summary of Comprehensive income (loss) for the periods presented.

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Net Income	$ 185,380	$ 180,927	$ 129,683
Reclassification of realized loss on interest rate hedge of 7.625% $325 million note due 2010 into net income		1,186	1,872
Reclassification of realized loss on interest rate hedge of 7.000% $250 million note due 2012 into net income	1,228	1,228	1,228
Reclassification of realized gain on interest rate hedge of 9.190% $150 million note due 2024 into net income	(462)	(462)	(462)
Reclassification of realized loss on interest rate hedge of 9.393% $500 million note due 2029, net of tax $176, $176, $40	286	286	65
Settlement of realized loss on interest rate hedge due to debt retirement		530	
Realized loss on settlement of interest rate hedge, net of tax $0, $0, $3.5 million			(5,705)
Total other comprehensive income (loss)	1,052	2,768	(3,002)
Total comprehensive income	$ 186,432	$ 183,695	$ 126,681

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8. Debt Obligations

The following table sets forth the debt obligations of Citrus and Florida Gas at the dates indicated.

	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Citrus:				
Revolving credit agreement due 2012	$ 181,000	$ 179,828	$ 178,500	$ 174,632
Construction and term loan agreement due 2029	500,000	765,306	500,000	711,531
Florida Gas:				
10.110% senior notes due 2013	28,000	30,447	42,000	47,174
9.190% senior notes due 2024	97,500	132,416	105,000	142,067
7.000% senior notes due 2012	250,000	265,388	250,000	277,094
7.900% senior notes due 2019	600,000	804,647	600,000	756,398
4.000% senior notes due 2015	350,000	379,341	350,000	366,779
5.450% senior notes due 2020	500,000	573,750	500,000	541,841
Revolving credit agreement due 2012	234,000	232,485	89,000	87,072
Total debt outstanding	$ 2,740,500	$ 3,363,608	$ 2,614,500	$ 3,104,588
Less current portion of long-term debt	686,500		21,500	
Less unamortized debt discount and swap loss	1,587		1,850	
Total long-term debt	$ 2,052,413		$ 2,591,150	
Stockholder promissory notes	$ 74,000		$	

As of December 31, 2011, the Company has scheduled long-term debt payments, excluding unamortized debt discount, as follows:

	2012	2013	2014	2015	2016	2017 and thereafter
			(In thousands)			
Citrus	181,000		74,000	13,793	13,793	472,414
Florida Gas	505,500	21,500	7,500	357,500	7,500	1,160,000
	$ 686,500	$ 21,500	$ 81,500	$ 371,293	$ 21,293	$ 1,632,414

The Florida Gas revolving credit agreement, with a maximum available capacity of $279 million, (*2007 Florida Gas Revolver*) matures on August 16, 2012. As of December 31, 2011, the amount drawn under the 2007 Florida Gas Revolver was $234 million with a weighted average interest rate of 0.63 percent (based on the London Interbank Offered Rate (LIBOR) plus 0.36 percent) and a facility fee of 0.09 percent.

The Citrus revolving credit facility, with a maximum available capacity of $186 million, (*2007 Citrus Revolver*) matures on August 16, 2012. As of December 31, 2011, the amount drawn under the 2007 Citrus Revolver was $181 million with a weighted average interest rate of 0.63 percent (based on LIBOR plus 0.36 percent), and a facility fee of 0.09 percent.

On March 31, 2011, Citrus entered into a promissory note (*Stockholder Promissory Notes*) with each of its stockholders for up to $150 million. The Stockholder Promissory Notes have a final maturity date of March 31, 2014, with no principal payments required prior to the maturity date, and bear an interest rate equal to a one-month Eurodollar rate plus a credit spread of 1.5 percent. Amounts may be redrawn periodically under the notes to temporarily fund capital expenditures, debt retirements, or other working capital needs. As of December 31, 2011, the amount drawn on each promissory note was $37 million, net of repayments. Citrus primarily utilized the proceeds for the purpose of funding Phase VIII-related expenditures.

The estimated fair values of the 2007 Florida Gas Revolver and 2007 Citrus Revolver at December 31, 2011 are approximately 99 percent of their carrying values. Estimated fair value amounts of other long-term debt were obtained from

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independent parties and are based upon market quotations of similar debt at interest rates currently available. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2011 and 2010 are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

The Company expects to refinance Florida Gas $250 million senior notes due July 2012 and extend the maturity or refinance both of the 2007 Citrus Revolver and the 2007 Florida Gas Revolver, each due August 2012. Alternatively, should the Company not be successful in such efforts, the Company may choose to retire such debt upon maturity by utilizing some combination of cash flows from operations, utilizing available funds on existing sponsor loans from its stockholders, requesting additional sponsor loans from its stockholders and altering the timing of controllable expenditures, among other things. The Company has obtained commitment letters from each of its stockholders to make additional sponsor loans in the event that the repayment of the senior notes and revolvers is necessary. However, the Company reasonably believes, based on its investment grade credit ratings and general financial condition, successful historical access to capital and debt markets and market expectations regarding the Company s future earnings and cash flows, that it will be able to refinance and/or retire these obligations, as applicable, under acceptable terms prior to their maturity.

In July 2010, Florida Gas issued $500 million of 5.45 percent senior notes due July 15, 2020 with an offering price of $99.826 (per $100 principal) and $350 million of 4.00 percent senior notes due July 15, 2015 with an offering price of $99.982 (per $100 principal). Florida Gas utilized the net proceeds to partially fund the Phase VIII Expansion project and for general corporate purposes, which included the repayment of a portion of Florida Gas outstanding debt. On July 19, 2010, Florida Gas: (i) made a $98.6 million distribution to Citrus, (ii) repaid $83 million that was outstanding under its credit agreements, and (iii) invested the remainder of the proceeds. On August 19, 2010, Florida Gas redeemed its $325 million of 7.625 percent senior notes due December 1, 2010. The debt retirement included accrued interest of $5.4 million and a $6.5 million redemption premium.

Under the terms of its debt agreements, Florida Gas may incur additional debt to refinance maturing obligations if the refinancing does not increase aggregate indebtedness, and thereafter, if Citrus and Florida Gas consolidated debt does not exceed specific debt to total capitalization ratios, as defined in certain debt instruments. Incurrence of additional indebtedness to refinance the current maturities would not result in a debt to capitalization ratio exceeding these limits.

The agreements relating to Citrus and Florida Gas debt include, among other things, restrictions as to the sales of assets and payment of dividends as well as maintenance of certain restrictive financial covenants, including a maximum allowable ratio of funded debt to total capitalization. The Company is subject, under the currently most restrictive debt covenant of a maximum 65 percent of consolidated funded debt to total capitalization, to a limitation of $748.8 million of total additional indebtedness at December 31, 2011.

As of December 31, 2011, Citrus debt obligations include the Construction Loan Agreement, the Stockholder Promissory Notes and $181 million outstanding on its revolving credit agreement, in addition to all of Florida Gas debt obligations. Florida Gas guarantees the Citrus revolving credit agreement indebtedness; however, Florida Gas assets are not pledged as collateral for any of the aforementioned Citrus debt. All of the debt obligations of Citrus and Florida Gas have events of default that contain commonly used cross-default provisions. An event of default by either Citrus or Florida Gas on any of their borrowed money obligations, in excess of certain thresholds which is not cured within defined grace periods, would cause the other debt obligations of Citrus and Florida Gas to be accelerated. As of December 31, 2011, the Company is not in default of any of its debt obligations.

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9. Benefits

Postretirement Benefit Plans

Florida Gas has postretirement health care and life insurance plans (*other postretirement plans*) that cover substantially all employees. The health care plan generally provides for cost sharing between Florida Gas and its retirees in the form of retiree contributions, deductibles and coinsurance on the amount Florida Gas pays annually to provide future retiree health care coverage under certain of these plans.

Obligations and Funded Status. Other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following tables contain information at the dates indicated about the obligations and funded status of Florida Gas other postretirement plans.

	Other Postretirement Benefits December 31,	
	2011	2010
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of period	$ 20,399	$ 17,671
Service cost	771	658
Interest cost	1,151	1,044
Actuarial (gain) loss and other	2,923	1,486
Benefits paid, net	(107)	(557)
Medicare Part D subsidy receipts	77	97
Early Retiree Reinsurance Program receipts	46	
Benefit obligation at end of year	25,260	20,399
Change in plan assets:		
Fair value of plan assets at beginning of period	13,335	10,654
Return on plan assets and other	84	1,257
Employer contributions	2,316	1,981
Benefits paid, net	(107)	(557)
Fair value of plan assets at end of period	15,628	13,335
Amount underfunded at end of period[1]	$ 9,632	$ 7,064
Amounts recognized in the Consolidated Balance Sheet consist of:		
Regulatory assets (Note 12)	$ 9,632	$ 7,064
Deferred credits - other (Note 13)	(9,632)	(7,064)
	$	$

(1) The underfunded balance is recognized as a deferred credit other, offset by a regulatory asset for amounts due from customers, in the Consolidated Balance Sheets.

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Net Periodic Benefit Cost. Net periodic benefit cost of Florida Gas other postretirement benefit plan for the periods presented includes the components noted in the table below.

	Other Postretirement Benefits Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Service cost	$ 771	$ 658	$ 529
Interest cost	1,151	1,044	945
Expected return on plan assets	(635)	(557)	(441)
Prior service cost amortization	1,195	1,195	1,088
Actuarial gain amortization		(137)	
Net periodic benefit cost	$ 2,482	$ 2,203	$ 2,121

The estimated prior service credit for other postretirement plans that will be amortized from Accumulated other comprehensive income into net periodic benefit cost during 2012 is $1.2 million.

Assumptions

The weighted-average discount rate used in determining benefit obligations was 4.24 percent and 5.52 percent at December 31, 2011 and 2010, respectively.

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below.

	Years Ended December 31,		
	2011	2010	2009
Discount rate	5.52%	5.97%	6.14%
Expected return on plan assets	4.50%	5.00%	5.00%

Florida Gas employs a building block approach in determining the expected long-term rate of return on the plans assets with proper consideration for diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to check for reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by the plans are shown in the table below.

	December 31,	
	2011	2010
Health care cost trend rate assumed for next year	8.50%	8.00%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	4.75%	4.85%
Year that the rate reaches the ultimate trend rate	2019	2017

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Assumed health care cost trend rates have a significant effect on the amounts reported for the healthcare plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost	$ 230	$ (220)
Effect on accumulated postretirement benefit obligation	2,936	(2,719)

Plan Assets. Florida Gas overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing long-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement benefit plan asset portfolio, Florida Gas has targeted the following asset allocations: equity of 25 percent to 35 percent, fixed income of 65 percent to 75 percent and cash and cash equivalents of 0 percent to 10 percent. These target allocations are monitored by the Board of Directors in conjunction with an external investment advisor. On occasion, the asset allocations may fluctuate as compared to these guidelines as a result of the Board of Directors actions.

The fair value of Florida Gas other postretirement plan assets at the dates indicated by asset category is as follows:

	Fair Value as of December 31, 2011	2010
	(In thousands)	
Asset Category:		
Cash and cash equivalents	$	$
Mutual fund[1]	15,628	13,335
Total	$ 15,628	$ 13,335

[1] This fund of funds invests primarily in a diversified portfolio of equity, fixed income and short-term mutual funds. As of December 31, 2011, the fund was primarily comprised of approximately 19 percent large-cap U.S. equities, 2 percent small-cap U.S. equities, 10 percent international equities, 55 percent fixed income securities, 8 percent cash, and 6 percent in other investments. As of December 31, 2010, the fund was primarily comprised of approximately 17 percent large-cap U.S. equities, 4 percent small-cap U.S. equities, 10 percent international equities, 57 percent fixed income securities, 10 percent cash, and 2 percent in other investments.

The other postretirement plan assets are classified as Level 1 assets within the fair-value hierarchy as their values are based on active market quotes. See *Note 2 Summary of Significant Accounting Policies and Other Matters Fair Value Measurement* for information related to the framework used by the Company to measure the fair value of its other postretirement plan asset.

Contributions. Florida Gas expects to contribute approximately $2.2 million to its other postretirement benefit plan in 2012 and approximately $2.2 million annually thereafter, until modified by future rate case proceedings.

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Benefit Payments. Florida Gas estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below.

Years	Expected Benefits Before Effect of Medicare Part D	Payments Medicare Part D Subsidy Receipts	Net
		(In thousands)	
2012	$ 711	$ 93	$ 618
2013	849	104	745
2014	953	119	834
2015	1,071	132	939
2016	1,189	149	1,040
2017-2021	7,975	1,001	6,974

The Medicare Prescription Drug Act provides a prescription drug benefit under Medicare (*Medicare Part D*) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Defined Contribution Plan

Florida Gas sponsors a defined contribution savings plan (*Savings Plan*) that is available to all employees. Florida Gas provides matching contributions of 100 percent of the first five percent for a maximum of five percent of the participant s compensation paid into the Savings Plan. Florida Gas contributions are 100 percent vested after five years of continuous service. Florida Gas contributions to the Savings Plan during the years ended December 31, 2011, 2010 and 2009 were $1.2 million, $1.0 million and $1.1 million, respectively.

In addition, Florida Gas makes employer contributions to separate accounts, collectively referred to as the Profit Sharing Plan, within the defined contribution plan. The contribution amounts are five percent of compensation. Florida Gas contributions are 100 percent vested after five years of continuous service. Florida Gas contributions to the Profit Sharing Plan during the years ended December 31, 2011, 2010 and 2009 were $1.6 million, $1.5 million and $1.4 million, respectively.

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10. Taxes on Income

The following table provides a summary of the current and deferred components of income tax expense for the periods presented:

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Current income taxes			
Federal	$ (85,064)	$ 45,059	$ 38,954
State	(816)	6,704	3,259
Total current income taxes	(85,880)	51,763	42,213
Deferred income taxes			
Federal	185,614	52,291	30,793
State	11,124	8,311	5,423
Total deferred income taxes	196,738	60,602	36,216
Total income tax expense	$ 110,858	$ 112,365	$ 78,429
Effective tax rate	37.4%	38.3%	37.7%

The actual income tax expense differs from the amount computed by applying the statutory federal tax rate of 35 percent to income before income taxes as follows:

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Computed statutory income tax expense at 35%	$ 103,683	$ 102,652	$ 72,839
Changes in income taxes resulting from:			
State income tax, net of federal income tax benefit	6,700	9,760	5,643
Permanent differences and other	475	(47)	(53)
Total income tax expense	$ 110,858	$ 112,365	$ 78,429

The Company files a consolidated federal income tax return separate from those of its stockholders. Florida Gas is included in the consolidated federal income tax return filed by Citrus. Pursuant to a tax sharing agreement with Citrus, Florida Gas will pay its share of taxes based on its taxable income, which will generally equal the liability that Florida Gas would have incurred as a separate taxpayer.

The $84.9 million *Income tax asset* on the Consolidated Balance Sheets as of December 31, 2011 represents the carryback of a portion of the forecasted 2011 net operating loss (for tax purposes) to 2009 and 2010 primarily resulting from 50% bonus depreciation on assets placed in service in 2011, including the Phase VIII assets.

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Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the Company s deferred tax assets (liabilities) at the dates indicated.

	December 31, 2011	December 31, 2010
	(In thousands)	
Deferred income tax assets:		
Regulatory and other reserves	$ 992	$ 10,752
Federal net operating loss	304,399	
Total deferred income tax assets	305,391	10,752
Deferred income tax liabilities:		
Depreciation and amortization	(1,399,094)	(903,085)
Other	(968)	(2,946)
Total deferred income tax liabilities	(1,400,062)	(906,031)
Net deferred tax liability	$ (1,094,671)	$ (895,279)
Less current portion of deferred income tax assets	58,056	
Accumulated deferred income taxes	$ (1,152,727)	$ (895,279)

The $58.1 million *Deferred tax asset*, carried as current on the Consolidated Balance Sheets, represents the carryforward of a portion of the forecasted 2011 net operating loss (for tax purposes) to 2012 s forecasted net income. The Company evaluates its tax reserves (*unrecognized tax benefits*) under the recognition, measurement and derecognition thresholds. The amount of unrecognized tax benefits did not have a material impact to the Company s consolidated financial statements.

11. Property, Plant and Equipment

The following table provides a summary of property, plant and equipment at the dates indicated.

	Lives in Years	December 31, 2011	December 31, 2010
		(In thousands)	
Transmission	20-60	$ 6,201,558	$ 3,552,004
General	3-40	25,612	22,014
Intangibles[1]	6-10	31,004	28,433
Construction work-in-progress		48,447	2,217,174
Acquisition adjustment	62.5	1,252,466	1,252,466
		7,559,087	7,072,091
Less accumulated depreciation and amortization		1,799,172	1,667,360

Net property, plant and equipment	$ 5,759,915	$ 5,404,731

(1) Includes capitalized computer software costs totaling:

Computer software cost	$ 25,959	$ 23,789
Less accumulated amortization	11,763	9,856
Net computer software costs	$ 14,196	$ 13,933

Amortization expense of capitalized computer software costs for the years ended December 31, 2011, 2010 and 2009 was

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$2.4 million, $2.5 million and $1.7 million, respectively. Computer software costs are amortized over 10 years. Expected amortization expense for computer software costs for the years 2012 through 2016 is: $2.3 million, $2.3 million, $2.1 million, $1.9 million and $1.8 million, respectively.

12. Regulatory Assets

The principal components of the Company s regulatory assets at the dates indicated were as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Ramp-up assets, net[1]	$ 10,524	$ 10,681
Fuel tracker	9,220	
Other postretirement benefits (Note 9)	9,632	7,064
Environmental reserve (Note 14)	888	1,036
Asset retirement obligations (Note 6)	1,144	1,341
Other miscellaneous	1,321	1,603
Total regulatory assets	$ 32,729	$ 21,725

(1) Ramp-up assets are regulatory assets which Florida Gas was specifically allowed to establish in the FERC certificates authorizing the Phase IV and V Expansion projects.

13. Deferred Credits

The principal components of the Company s regulatory liabilities at the dates indicated were as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Balancing tools[1]	$ 12,822	$ 5,455
Fuel tracker		3,908
Total regulatory liabilities	$ 12,822	$ 9,363

(1) Balancing tools are a regulatory method by which Florida Gas recovers or refunds the net costs of operational natural gas balancing of the pipeline s system. The balance can be a deferred charge or credit, depending on timing, rate changes and operational activities.

CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The principal components of the Company s other deferred credits at the dates indicated were as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Post construction mitigation costs	$ 2,356	$ 1,071
Other postretirement benefits (Note 9)	9,632	7,064
Environmental reserve	1,167	1,120
Tax reserve	461	3,297
Asset retirement obligations (Note 6)	2,428	3,003
Other miscellaneous	1,828	1,003
Total deferred credits - other	$ 17,872	$ 16,558

14. Commitments and Contingencies

Litigation and Other Claims

Florida Gas Pipeline Relocation Costs. A dispute exists with the Florida Department of Transportation, Florida s Turnpike Enterprise (*FDOT/FTE*) over the rights of Florida Gas under certain easements and other agreements associated with the State Road 91 projects to, among other matters, receive reimbursement for the relocation costs incurred by Florida Gas and the nature and scope of such easements. The first phase of the State Road 91 projects included replacement of approximately 11.3 miles of existing 18- and 24-inch pipelines in Broward County, Florida due to the widening of State Road 91 by the FDOT/FTE. Construction is complete and the new facilities were placed in service in March 2008. This dispute, among others, is being litigated in Broward County, Florida. On January 27, 2011, the jury awarded Florida Gas $82.7 million and rejected all damage claims by the FDOT/FTE. On May 2, 2011, the judge issued an order entitling Florida Gas to an easement of 15 feet on either side of its pipelines and 75 feet of temporary work space. The judge further ruled that Florida Gas is entitled to approximately $8 million in interest. In addition to ruling on other aspects of the easement, he ruled that pavement could not be placed directly over Florida Gas pipeline without the consent of Florida Gas, although Florida Gas would be required to relocate the pipeline if it did not provide such consent. He also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011. Briefing to the Florida Fourth District Court of Appeals (*4th DCA*) is complete. The 4th DCA granted a request by the FDOT to expedite the appeal. Oral argument is set for March 7, 2012. Amounts ultimately received would primarily reduce Florida Gas property, plant and equipment costs.

A 2007 action brought by the FDOT/FTE against Florida Gas in Orange County, Florida, seeking a declaratory judgment that, under existing agreements, Florida Gas is liable for the costs of relocation associated with FDOT/FTE projects, has been stayed pending resolution of the Broward County, Florida action.

On April 14, 2011 Florida Gas filed suit against the FDOT/FTE, Dragados USA and I-595 Express, LLC in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in Florida Gas easements. The same judge that presided over the previously discussed FDOT/FTE proceeding was assigned to the case. Trial is expected to be set in the third quarter of 2012.

Florida Gas will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that Florida Gas will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate Florida Gas for its costs.

CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Liabilities for Litigation and Other Claims

In addition to the matters discussed above, the Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business.

The Company records accrued liabilities for litigation and other claim costs when management believes a loss is probable and reasonably estimable. When management believes there is at least a reasonable possibility that a material loss or an additional material loss may have been incurred, the Company discloses (i) an estimate of the possible loss or range of loss in excess of the amount accrued; or (ii) a statement that such an estimate cannot be made. As of December 31, 2011 and 2010, the Company has recorded litigation and other claim-related accrued liabilities of $0.7 million and $0.6 million, respectively. Except for the matters discussed above, the Company does not have any material litigation or other claim contingency matters assessed as probable or reasonably possible that would require disclosure in the financial statements.

Liquidity and Capital Resources

Cash generated from internal operations constitutes the Company s primary source of liquidity. The Company s working capital deficit at December 31, 2011 is $587.0 million, which includes the current portion of long-term debt, $686.5 million. Additional sources of liquidity for working capital purposes may include contributions from its stockholders and new capital market debt. The availability and terms relating to such liquidity will depend upon various factors and conditions such as the Company s combined cash flow and earnings, the Company s resulting capital structure and conditions in the financial markets at the time of such offerings.

Environmental Matters

The Company s operations are subject to federal, state and local laws and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Company to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with environmental laws, rules and regulations may expose the Company to significant fines, penalties and/or interruptions in operations. The Company s environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future. The Company engages in a process of updating and revising its procedures for the ongoing evaluation of its operations to identify potential environmental exposures and enhance compliance with regulatory requirements.

Florida Gas conducts assessment, remediation, and ongoing monitoring of soil and groundwater impact which resulted from its past waste management practices at its Rio Paisano and Station 11 facilities. The liability is recognized in other current liabilities and in other deferred credits and in total amounted to $1.2 million and $1.4 million at December 31, 2011 and 2010, respectively. Amounts are not discounted because of uncertainty related to timing. Costs of $0.1 million, $0.1 million and $0.1 million were expensed during the years ended December 31, 2011, 2010 and 2009, respectively. Florida Gas recorded the estimated costs of remediation to be spent after April 1, 2010 as a regulatory asset. The balance of the regulatory asset was $0.9 million and $1.0 million at December 31, 2011 and 2010, respectively. See *Note 12 Regulatory Assets*.

Future Regulatory Compliance Commitments

Air Quality Control. In August 2010, the United States Environmental Protection Agency (*EPA*) finalized a rule that requires reductions in a number of pollutants, including formaldehyde and carbon monoxide, for certain engines regardless of size at Area Sources (sources that emit less than ten tons per year of any one Hazardous Air Pollutant (*HAP*) or twenty-five tons per year of all HAPs) and engines less than 500 horsepower at Major Sources (sources that emit ten tons per year or more of any one HAP or twenty-five tons per year of all HAPs). Compliance is required by October 2013. It is anticipated that the limits adopted in this rule will be used in a future EPA rule that is scheduled to be finalized in 2013, with compliance required in 2016. This future rule is expected to require reductions in formaldehyde and carbon monoxide emissions from engines greater than 500 horsepower at Major Sources.

CITRUS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Nitrogen oxides are the primary air pollutant from natural gas-fired engines. Nitrogen oxide emissions may form ozone in the atmosphere. In 2008, the EPA lowered the ozone standard to seventy-five parts per billion (*ppb*) with compliance anticipated in 2013 to 2015. In January 2010, the EPA proposed lowering the standard to sixty to seventy ppb in lieu of the seventy-five ppb standard, with compliance required in 2014 or later. In September 2011, the EPA decided to rescind the proposed lower ozone standard and begin the process to implement the 75 ppb ozone standard established in 2008.

In January 2010, the EPA finalized a 100 ppb one-hour nitrogen dioxide standard. The rule requires the installation of new nitrogen dioxide monitors in urban communities and roadways by 2013. This new monitoring may result in additional nitrogen dioxide non-attainment areas. In addition, ambient air quality modeling may be required to demonstrate compliance with the new standard.

The Company is currently reviewing the potential impact of the August 2010 Area Source National Emissions Standards for Hazardous Air Pollutants rule, implementation of the 2008 ozone standard and the new nitrogen dioxide standard on operations and the potential costs associated with the installation of emission control systems on its existing engines. The ultimate costs associated with these activities cannot be estimated with any certainty at this time, but the Company believes, based on the current understanding of the current and proposed rules, such costs will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Other Commitments and Contingencies

Federal Pipeline Integrity Rules. On December 15, 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule defines as high consequence areas (*HCAs*). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The rule required operators to identify HCAs along their pipelines and to complete baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing or direct assessments, by December 2012. Operators were required to rank the risk of their pipeline segments containing HCAs, assessments are generally conducted on the higher risk segments first. In addition, some system modifications will be necessary to accommodate the in-line inspections. As of December 31, 2011, Florida Gas had completed approximately 96 percent of the baseline risk assessments required to be completed by December 2012. While identification and location of all the HCAs has been completed, it is not practicable to determine with certainty the total scope of required remediation activities prior to completion of the assessments and inspections. The required modifications and inspections are currently estimated to be in the range of approximately $30 million to $40 million per year through 2012.

Leases. The Company utilizes assets under operating leases in several areas of operations. Rental expenses amounted to $4.8 million in 2011, $3.0 million in 2010 and $3.2 million in 2009. Future minimum rental payments under the Company s various operating leases for the years 2012 through 2016 are: $2.5 million, $2.5 million, $2.9 million, $2.6 million and $2.7 million, respectively, and $6.7 million in total thereafter.

See *Note 4 Regulatory Matters* for other potential contingent matters applicable to the Company.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 27th day of February 2012.

EL PASO CORPORATION

By: /s/ Douglas L. Foshee
Douglas L. Foshee
President and Chief Executive Officer

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

Signature	Title	Date
/s/ Douglas L. Foshee Douglas L. Foshee	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 27, 2012
/s/ John R. Sult John R. Sult	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2012
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	February 27, 2012
/s/ Juan Carlos Braniff Juan Carlos Braniff	Director	February 27, 2012
/s/ David W. Crane David W. Crane	Director	February 27, 2012
/s/ Robert W. Goldman Robert W. Goldman	Director	February 27, 2012
/s/ Anthony W. Hall, Jr. Anthony W. Hall, Jr.	Director	February 27, 2012
/s/ Thomas R. Hix Thomas R. Hix	Director	February 27, 2012
/s/ Ferrell P. McClean Ferrell P. McClean	Director	February 27, 2012
/s/ Timothy J. Probert Timothy J. Probert	Director	February 27, 2012
/s/ Steven J. Shapiro Steven J. Shapiro	Director	February 27, 2012
/s/ J. Michael Talbert J. Michael Talbert	Director	February 27, 2012

/s/ Robert F. Vagt Robert F. Vagt	Director	February 27, 2012
/s/ John L. Whitmire John L. Whitmire	Director	February 27, 2012

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EL PASO CORPORATION

EXHIBIT INDEX

December 31, 2011

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by * . All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement.

Exhibit Number	Description
2.A	Agreement and Plan of Merger, dated as of October 16, 2011, by and among El Paso Corporation, Sirius Holdings Merger Corporation, Sirius Merger Corporation, Kinder Morgan, Inc. Sherpa Merger Sub, Inc and Sherpa Acquisition, LLC (Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
2.B	Agreement and Plan of Merger, dated as of October 16, 2011, by and among El Paso Corporation, Sirius Holdings Merger Corporation and Sirius Merger Corporation (Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
3.A	Second Amended and Restated Certificate of Incorporation (Exhibit 3.A to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
3.B	By-laws effective as of May 6, 2009 (Exhibit 3.B to our Current Report on Form 8-K filed with the SEC on May 6, 2009).
4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4.A to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (Exhibit 4.B to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
*4.C	Tenth Supplemental Indenture dated as of December 28, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999.
*4.D	Eleventh Supplemental Indenture dated as of August 31, 2006, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999.
4.E	Twelfth Supplemental Indenture dated as of June 18, 2007 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Quarterly Report on Form 10-Q for the period ended June 30, 2007, filed with the SEC on August 7, 2007).
4.F	Thirteenth Supplemental Indenture dated as of May 30, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4 to our Quarterly Report on Form 10-Q for the period ended June 30, 2008, filed with the SEC on August 8, 2008).
4.G	Fourteenth Supplemental Indenture dated as of December 12, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.H to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
4.H	Fifteenth Supplemental Indenture, dated as of February 9, 2009 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.I to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
4.I	Sixteenth Supplemental Indenture, dated as of September 24, 2010, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).

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Exhibit Number	Description
+10.A	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of January 1, 2007 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of January 1, 2008 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003(Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
+10.B	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.B to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
+10.B.1	Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.B.1 to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
+10.B.2	Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.B.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.B.3	Amendment No. 3 effective as of October 26, 2006 to the Stock Option Plan for Non-Employee Directors.
+10.C	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001(Exhibit 10.C to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*10.C.1	Amendment No. 3 effective as of October 26, 2006 to the 2001 Stock Option Plan for Non-Employee Directors.
+10.D	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.F. to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan. (Exhibit 10.F.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.5 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
*10.D.1	Amendment No. 6 effective as of October 26, 2006 to the 2001 Omnibus Incentive Compensation Plan.
+10.E	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.E.1	Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.G.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008);

Exhibit Number	Description
10.E.2	Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
10.E.3	Amendment No. 3 effective December 15, 2004 to the Supplemental Benefits Plan (Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
*10.E.4	Amendment No. 4 to the Supplemental Benefits Plan effective as of December 31, 2004.
10.E.5	Amendment No. 5 effective as of January 1, 2007 to the Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.F	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.G to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
+10.F.1	Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.H.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.F.2	Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.H.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.G	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan(Exhibit 10.I.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 5 effective as of January 1, 2007 to the Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.H	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.I to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of January 1, 2007 to the 2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.J.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.I	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.K.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.J.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
+10.J	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.L to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.L.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan (Exhibit 10.L.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan (Exhibit 10.L.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.L.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).

Exhibit Number	Description
*+10.J.1	Amendment No. 5 effective as of October 26, 2006 to the Strategic Stock Plan.
+10.K	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.O to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.O.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.O.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management (Exhibit 10.O.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.O.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.K.1	Amendment No. 5 effective as of October 26, 2006 to the Omnibus Plan for Management Employees.
+10.L	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.T to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
*+10.M	Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto.
+10.N	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 15, 2004 (Exhibit 10.R to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
+10.O	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.P to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).
+10.O.1	Amendment No. 1 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of October 26, 2006.
+10.O.2	Amendment No. 2 effective as of January 1, 2007 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.O.3	Amendment No. 3 effective as of January 1, 2008 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
+10.P	El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated effective May 19, 2010 (incorporated by reference to Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 20, 2010).
10.Q	Form of stock option and restricted stock award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan, effective as of May 19, 2010 (Exhibit 10.R to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011); Form of performance share award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan, effective as of May 19, 2010 (Exhibit 10.R.1 to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011).

Exhibit Number	Description
+10.R	2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.S to our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011); Amendment No. 1 effective as of January 1, 2007 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.BB.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of January 1, 2008 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005. (Exhibit 10.BB.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
10.S	Fourth Amended and Restated Credit Agreement dated as of May 27, 2011, among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent for the Lenders (Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.T	Fourth Amended and Restated Security Agreement dated as of May 27, 2011, among El Paso Corporation, the persons referred to therein as Pipeline Company Borrowers, the persons referred to therein as Subsidiary Grantors, and JPMorgan Chase Bank, N.A., as Collateral Agent and Depository Bank (Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.U	Third Amended and Restated Credit Agreement dated as of June 2, 2011, among El Paso Exploration and Production Company and El Paso E&P Company, L.P., as Borrowers and BNP Paribas, as Administrative Agent (Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 8, 2011).
10.V	Credit Agreement dated as of May 3, 2010 among Ruby Pipeline, L.L.C, as the Borrower, Société Générale, as the Administrative Agent, Deutsche Bank Trust Company Americas, as the Common Security Trustee, Construction/Term Loan Lenders, DSRA Issuing Banks, and Revolving Loan Lender/Issuing Bank (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.W	Non-Completion Loan Guaranty by El Paso Corporation, as the Guarantor, in favor of Société Générale as the Administrative Agent, dated as of May 3, 2010 (incorporated by reference to Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.X	Registration Rights Agreement dated September 24, 2010 (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).
10.Y	Voting Agreement, dated as of October 16, 2011, by and among El Paso Corporation, Richard D. Kinder, GS Capital Partners V Fund, L.P., GSCP V Offshore Knight Holdings, L.P., GSCP V Germany Knight Holdings, L.P., GS Capital Partners V Institutional, L.P., GS Capital Partners VI Fund, L.P., GSCP VI Offshore Knight Holdings, L.P., GSCP VI Germany Knight Holdings, L.P., GS Capital Partners VI Parallel, L.P., Goldman Sachs KMI Investors, L.P., GSCP KMI Investors, L.P., GSCP KMI Investors Offshore, L.P., GS Infrastructure Knight Holdings, L.P., GS Infrastructure Partners, I, L.P., GS Global Infrastructure Partners I, L.P., Highstar II Knight Acquisition Sub, L.P., Highstar III Knight Acquisition Sub, L.P., Highstar Knight Partners, L.P., Highstar KMI Blocker LLC, Carlyle Partners IV Knight, L.P., CP IV Coinvestment, L.P., Carlyle Energy Coinvestment III, L.P., Carlyle/Riverstone Knight Investment Partnership, L.P., C/R Knight Partners, L.P., C/R Energy III Knight Non-U.S. Partnership, L.P., and Riverstone Energy Coinvestment III, L.P. Corporation (Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
+10.Z	El Paso Corporation EP Energy Employee Retention Plan (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on January 24, 2012).
+10.AA	Form of Tier II-A Participant Award Letter adopted under El Paso Corporation EP Energy Employee Retention Plan (Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on January 24, 2012).
*12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
*21	Subsidiaries of El Paso Corporation.

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Exhibit Number	Description
*23.A	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
*23.B	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers, LLP (Citrus Corp. and Subsidiaries)
*23.D	Consent of Ryder Scott Company, L.P.
*31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.A	Ryder Scott Company, L.P. reserve report for El Paso Production Company as of December 31, 2011.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Schema Document.
*101.CAL	XBRL Calculation Linkbase Document.
*101.DEF	XBRL Definition Linkbase Document.
*101.LAB	XBRL Labels Linkbase Document.
*101.PRE	XBRL Presentation Linkbase Document.