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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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.

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PART I

ITEM 1. BUSINESS

Business and Strategy

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

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

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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

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 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.

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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.

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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.

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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.

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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.

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.

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.

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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