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.

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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

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

Eagle Ford Shale

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

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

Wolfcamp Shale

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

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

Other Southern:

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

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

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

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International

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

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

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

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

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

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

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

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Oil and Natural Gas Properties

Oil and Condensate, Natural Gas and NGL Reserves and Production

The table below presents information about our estimated proved reserves as of December 31, 2011. These reserves are based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of oil and natural gas that are ultimately recovered. The risks and uncertainties associated with estimating proved oil and natural gas reserves are discussed further in Item 1A, Risk Factors. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2011.

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

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

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

Our consolidated reserves in the table above are consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

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The table below presents proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2011.

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

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

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

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

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare related to our investment in Four Star, our unconsolidated affiliate, has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is currently responsible for reserve reporting, strategy development, technical excellence and land administration. He has more than 24 years of industry experience in various domestic and international engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates.

Ryder Scott Company, L.P. (Ryder Scott) conducted an audit of the estimates of proved reserves prepared by us as of December 31, 2011. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our total proved reserves on a natural gas equivalent basis, representing 87 percent of the total discounted future net cash flows of these proved reserves. Ryder Scott also conducted an audit of the estimates we prepared of the proved reserves of Four Star as of December 31, 2011. In connection with the audit of these proved reserves, Ryder Scott reviewed 87 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 91 percent of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10 percent of Ryder Scott s estimates. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

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

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