

EL PASO CORP/DE  
Form 10-K  
March 01, 2011

**Table of Contents**

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

**Form 10-K**

**(Mark One)**

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

**For the fiscal year ended December 31, 2010**

**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**

**(State or Other Jurisdiction of  
Incorporation or Organization)**

**76-0568816**

**(I.R.S. Employer  
Identification No.)**

**El Paso Building  
1001 Louisiana Street  
Houston, Texas**

**(Address of Principal Executive Offices)**

**77002**

**(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  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 .

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  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  No .

Edgar Filing: EL PASO CORP/DE - Form 10-K

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       Accelerated filer       Non-accelerated filer       Smaller reporting company

(Do not check if a smaller reporting company)

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

**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, 2010, 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: \$7,821,067,148.

**Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.**

Common Stock, par value \$3 per share. Shares outstanding on February 22, 2011: 704,754,155

**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 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2011.

---

**EL PASO CORPORATION  
TABLE OF CONTENTS**

| <u><b>Caption</b></u>   | <b>Page</b> |
|---|-------------|
| <u><b>PART I</b></u>  |             |
| <u>Item 1. Business</u>   | 4           |
| <u>Item 1A. Risk Factors</u>  | 32          |
| <u>Item 1B. Unresolved Staff Comments</u>   | 48          |
| <u>Item 2. Properties</u>   | 48          |
| <u>Item 3. Legal Proceedings</u>  | 48          |
| <u>Item 4. (Removed and Reserved)</u>   | 48          |
| <u><b>PART II</b></u>   |             |
| <u>Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</u> | 49          |
| <u>Item 6. Selected Financial Data</u>  | 52          |
| <u>Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>                        | 53          |
| <u>Item 7A. Quantitative and Qualitative Disclosures About Market Risk</u>  | 90          |
| <u>Item 8. Financial Statements and Supplementary Data</u>  | 92          |
| <u>Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>                         | 163         |
| <u>Item 9A. Controls and Procedures</u>   | 163         |
| <u>Item 9B. Other Information</u>   | 163         |
| <u><b>PART III</b></u>  |             |
| <u>Item 10. Directors, Executive Officers and Corporate Governance</u>  | 164         |
| <u>Item 11. Executive Compensation</u>  | 164         |
| <u>Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</u>              | 164         |
| <u>Item 13. Certain Relationships and Related Transactions, and Director Independence</u>                                   | 164         |
| <u>Item 14. Principal Accounting Fees and Services</u>  | 164         |
| <u><b>PART IV</b></u>   |             |
| <u>Item 15. Exhibits and Financial Statement Schedules</u>  | 165         |
| <u>Signatures</u>   | 166         |
| <u>EX-3.A</u>   |             |
| <u>EX-4.A</u>   |             |
| <u>EX-4.B</u>   |             |
| <u>EX-10.B</u>  |             |
| <u>EX-10.B.1</u>  |             |
| <u>EX-10.G</u>  |             |
| <u>EX-10.P</u>  |             |
| <u>EX-10.R</u>  |             |
| <u>EX-10.R.1</u>  |             |
| <u>EX-10.S</u>  |             |
| <u>EX-12</u>  |             |
| <u>EX-21</u>  |             |
| <u>EX-23.A</u>  |             |
| <u>EX-23.B</u>  |             |

EX-23.C

EX-31.A

EX-31.B

EX-32.A

EX-32.B

EX-99.A

EX-101 INSTANCE DOCUMENT

EX-101 SCHEMA DOCUMENT

EX-101 CALCULATION LINKBASE DOCUMENT

EX-101 LABELS LINKBASE DOCUMENT

EX-101 PRESENTATION LINKBASE DOCUMENT

EX-101 DEFINITION LINKBASE DOCUMENT

---

**Table of Contents**

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

|       |  |
|-------|--|
| /d    | = per day  |
| Bbl   | = barrel   |
| BBtu  | = billion British thermal units                  |
| Bcf   | = billion cubic feet                             |
| Bcfe  | = billion cubic feet of natural gas equivalents  |
| LNG   | = liquefied natural gas                          |
| MBbls | = thousand barrels                               |
| Mcf   | = thousand cubic feet                            |
| Mcfe  | = thousand cubic feet of natural gas equivalents |
| 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 natural gas and oil in equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

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

**Table of Contents**

**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 newly formed 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.

**Pipelines Segment**

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through eight wholly or majority owned pipeline systems and two partially owned systems. These systems consist of approximately 43,100 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. Our Pipelines segment also includes storage and LNG terminalling related facilities including our ownership of storage capacity through our transmission systems, three underground natural gas storage facilities, and two LNG terminalling facilities, one of which is under construction and the other which is located in Elba Island, Georgia. We provide approximately 240 Bcf of storage capacity and our LNG receiving terminal has a peak sendout capacity of 1.8 Bcf/d. The size, connectivity and diversity of our U.S. pipeline systems provide growth opportunities through infrastructure development or large scale expansion projects and gives us the ability to adapt to shifting supply and demand. Our focus is to enhance the value of our transmission business by successfully executing on our backlog of committed expansion projects in the United States and developing growth projects in our market and supply areas.

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

providing outstanding customer service;

executing successfully on time and on budget our backlog of committed expansion projects;

developing new growth projects in our market and supply areas;

ensuring the safety of our pipeline systems and assets;

optimizing our contract portfolio; and

focusing on efficiency and synergies across our systems.

**Table of Contents**

*Natural Gas Pipeline Systems.* The tables below provide more information on our pipeline systems:

| Transmission System                               | Supply and Market Region  | Ownership Percentage (Percent) | As of December 31, 2010 |                          |                        | Average Throughput <sup>(1)</sup> |       |       |
|---|---|--------------------------------|-------------------------|--------------------------|------------------------|-----------------------------------|-------|-------|
|   |   |                                | Miles of Pipeline       | Design Capacity (MMcf/d) | Storage Capacity (Bcf) | 2010                              | 2009  | 2008  |
| 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                            | 14,100                  | 7,208                    | 93 <sup>(2)</sup>      | 5,081                             | 4,614 | 4,864 |
| 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 <sup>(3)</sup>     | 44                     | 3,356                             | 3,937 | 4,379 |
| 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 <sup>(4)</sup>       |                        | 421                               | 379   | 349   |
| Cheyenne Plains Gas Pipeline (CPG) <sup>(5)</sup> | Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.   | 100                            | 400                     | 934                      |                        | 751                               | 841   | 898   |

- (1) Includes throughput transported on behalf of affiliates.
- (2) Includes 29 Bcf of storage capacity from Bear Creek Storage Company, L.L.C (Bear Creek) which is owned equally by TGP and Southern Natural Gas (SNG).
- (3) Reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.
- (4) Reflects east to west flow capacity.
- (5) We own 100 percent of the common shares. See Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

**Table of Contents**

| Transmission System           | Supply and Market Region  | As of December 31, 2010         |       |                          | Average Throughput <sup>(1)</sup> |       |       |       |
|-------------------------------|---|---------------------------------|-------|--------------------------|-----------------------------------|-------|-------|-------|
|                               |   | Ownership of Pipeline (Percent) | Miles | Design Capacity (MMcf/d) | Storage Capacity (Bcf)            | 2010  | 2009  | 2008  |
| 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. | 72 <sup>(5)</sup>               | 4,300 | 4,592                    | 37 <sup>(3)</sup>                 | 2,131 | 2,299 | 2,225 |
| 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.                     | 71 <sup>(5)</sup>               | 7,600 | 3,700                    | 60 <sup>(2)</sup>                 | 2,505 | 2,322 | 2,339 |
| Wyoming Interstate (WIC)      | Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.  | 51 <sup>(5)</sup>               | 800   | 3,538                    |                                   | 2,472 | 2,652 | 2,543 |
| Elba Express                  | Extends from the Elba Island LNG terminal near Savannah to Hart County, Georgia and Anderson County, South Carolina. Also connects with SNG and various power plants in Georgia.  | 51 <sup>(5)</sup>               | 200   | 945                      |                                   | (4)   |       |       |
|                               |   | 50                              | 5,000 | 2,254                    |                                   | 2,288 | 2,250 | 2,147 |

Florida Gas Transmission (FGT)<sup>(6)</sup> Extends from south Texas to South Florida.

- (1) Includes throughput transported on behalf of affiliates and represents the systems totals and are not adjusted for our ownership interest.
- (2) Includes 29 Bcf of storage capacity from Bear Creek which SNG owns equally with TGP.
- (3) Includes 6 Bcf of storage capacity from Totem Gas Storage which is owned by WYCO Development L.L.C. (WYCO), our 50 percent equity investee.
- (4) This system was placed in service in March 2010 and although capacity is under contract, the average volumes transported during the year ended December 31, 2010 were not material.
- (5) Includes direct ownership of these systems and indirect ownership through our limited and general partner interest in our master limited partnership, El Paso Pipeline Partners, L.P. (EPB). As the general partner, we also hold incentive distribution rights which pay an increasing percentage interest in quarterly distributions as further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 14.
- (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.

**Table of Contents**

*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 Gas Storage facilities located in Northeast Colorado which are operated by us. The Totem Gas Storage facility consists of a 6 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.

*Federal Energy Regulatory Commission (FERC) Approved Pipeline Projects.* As of December 31, 2010, we had the following significant FERC approved pipeline expansion projects on our systems. For a further discussion of other expansion projects, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

| <b>Project</b>                                     | <b>Existing System</b> | <b>Capacity (MMcf/d)</b> | <b>Description</b>   | <b>Anticipated Completion or In-Service Date</b> |
|--|------------------------|--------------------------|--|--|
| FGT Phase VIII                                     | FGT                    | 800                      | To add more than 483 miles of pipeline loops, laterals, and mainline and 213,600 of horsepower compression   | April 2011                                       |
| Ruby Pipeline                                      |                        | 1,490                    | To add approximately 680 miles of pipeline and 157,000 of horsepower compression   | July 2011  |
| South System III<br>(Phases I-III)                 | SNG                    | 370                      | To add 81 miles of pipeline and 17,310 of horsepower compression; each phase will add an additional 122 MMcf/d of capacity                                 | 2011-2012 <sup>(1)</sup>                         |
| Southeast Supply Header<br>Phase II <sup>(2)</sup> | SNG                    | 350                      | To add approximately 26,000 of horsepower compression to the jointly owned pipeline facilities   | June 2011  |
| 300 Line Project                                   | TGP                    | 350                      | To add 128 miles of pipeline and approximately 55,000 horsepower of compression at two new compressor stations and at certain existing compressor stations | November 2011                                    |

<sup>(1)</sup> The South System III expansion project consists of three phases. In January 2011, Phase I of the project was placed in service. Phases II and III are expected to be placed in service in June 2011 and June 2012, respectively.

(2) This project is operated by Spectra Energy Corp.

*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:

| <b>Storage Facility</b> | <b>As of December 31, 2010</b>      |                               | <b>Location</b> |
|-------------------------|-------------------------------------|-------------------------------|-----------------|
|                         | <b>Ownership Interest (Percent)</b> | <b>Storage Capacity (Bcf)</b> |                 |
| Bear Creek              | 85 <sup>(1)</sup>                   | 58 <sup>(2)</sup>             | Louisiana       |
| Totem Gas Storage       | 36 <sup>(1)</sup>                   | 6 <sup>(3)</sup>              | Colorado        |
| Young Gas Storage       | 48                                  | 6 <sup>(4)</sup>              | 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.

**Table of Contents**

*LNG Facilities*

*Southern LNG Company, L.L.C. (SLNG).* We own a 51 percent interest in SLNG which owns a 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 subsidiaries of 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 is constructing an LNG terminal in Pascagoula, Mississippi with a peak sendout capacity of 1.5 Bcf/d that is expected to be placed in service in October 2011.

*Master Limited Partnership.* At December 31, 2010, our master limited partnership, EPB, owns (i) 100 percent of WIC, Elba Express, and SLNG, (ii) a 60 percent general partner interest in SNG and (iii) a 58 percent general partner interest in CIG. As of December 31, 2010, our ownership interest in EPB is 51 percent, including our 2 percent general partner interest.

*Markets and Competition*

Our Pipelines segment provides natural gas services to a variety of customers, including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear energy, wind, hydroelectric power, solar and fuel oil.

The natural gas industry is undergoing a major shift in supply sources. Production from conventional sources is declining while production from unconventional sources, such as shales, is rapidly increasing. This shift will affect the supply patterns, the 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. One of our pipelines is connected to two major shale formations: the Haynesville shale in northern Louisiana and Texas and the Marcellus shale in Pennsylvania. It is possible that gas from these sources will increasingly displace receipts over time from traditional sources in south Texas and the Gulf of Mexico on our system. In addition, one of our systems is near the Eagle Ford Shale formation in south Texas, which could be a major source of supply into the system in the future and could impact the flows on the system and the array of shipper contracts.

Another change in the supply patterns is the reduction in imports from Canada. This decrease has been the result of declining production and increasing demand in Canada. This reduction has led to increased demand for domestic supplies and related transportation services over the last several years, a trend which may continue in the future. On the other border, exports to Mexico are increasing and may increase further over time as demand growth exceeds production growth in that country. The increase in demand for gas and transportation caused by these trends in Canada and Mexico could be partially offset by imports of LNG. Imports of LNG have fluctuated in the past in response to changing gas prices within North America, Europe and Asia. LNG terminals and other regasification facilities can serve as alternate sources of supply for pipelines, enhancing their delivery capabilities and operational flexibility and complementing traditional supply transported into market areas.

**Table of Contents**

However, these LNG delivery systems may also compete with our pipelines for transportation of gas into the market areas we serve.

Electric power generation has been the source of most of the growth in demand for natural gas over the last 10 years, and this trend is expected to continue in the future. The growth of natural gas in this sector is influenced by competition with coal and increased consumption of electricity as a result of recent economic growth. Short-term market shifts have been driven by relative costs of coal-fired generation versus gas-fired generation. 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.

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, 2010 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.

**Table of Contents**

The following table details information related to our pipeline systems and certain other facilities, including the customers, contracts, markets served and the competition faced by each as of December 31, 2010. Firm customers reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities and are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Interruptible customers are customers without reserved capacity that pay usage charges based on the volume of gas they transport, store, inject or withdraw.

| <b>Customer Information</b>  | <b>Contract Information</b>   | <b>Competition</b>  |
|--|---|---|
| <p><b>TGP</b><br/>Approximately 410 firm and interruptible customers.</p> <p>Major Customer:<br/>National Grid USA and subsidiaries<br/>(495 BBtu/d)<br/>(332 BBtu/d)</p> <p><b>EPNG</b><br/>Approximately 150 firm and interruptible customers.</p> <p>Major Customers:<br/>Southern California Gas Company (SoCal)<br/>(782 BBtu/d)</p> <p>ConocoPhillips Company<br/>(527 BBtu/d)<br/>Southwest Gas Corporation</p> | <p>Approximately 470 firm transportation contracts. Weighted average remaining contract term of approximately four years.</p> <p>Expire in 2012-2013.<br/>Expire in 2014-2029.</p> <p>Approximately 200 firm transportation contracts. Weighted average remaining contract term of approximately three years.</p> <p>Expire in 2011-2014.</p> <p>Expire in 2011-2012.</p> | <p>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.</p> <p>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.</p> |

(485 BBtu/d)

Expire in 2011-2018.

**Table of Contents**

| <b>Customer Information</b>   | <b>Contract Information</b>   | <b>Competition</b>   |
|---|---|--|
| <p><b>MPC</b><br/>Approximately 10 firm and interruptible customers.</p>            | <p>Approximately two firm transportation contracts. Weighted average remaining contract term of approximately five years.</p> | <p>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.</p> |
| <p>Major Customer:<br/>EPNG<br/>(510 BBtu/d)</p>                                    | <p>Expires in 2015.</p>   |  |
| <p><b>CPG</b><br/>Approximately 50 firm and interruptible customers.</p>            | <p>Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately six years.</p>   | <p>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.</p>   |
| <p>Major Customers:<br/>Oneok Energy Services Company<br/>L.P.<br/>(195 BBtu/d)</p> | <p>Expires in 2015.</p>   |  |
| <p>Encana Marketing (USA) Inc.<br/>(170 BBtu/d)</p>                                 | <p>Expires in 2015.</p>   |  |
| <p>Anadarko Petroleum Corporation<br/>(195 BBtu/d)</p>                              | <p>Expire in 2015-2016.</p>   |  |
| <p>Shell Energy North America US,<br/>L.P.<br/>(125 BBtu/d)</p>                     | <p>Expires in 2019.</p>   |  |

**Table of Contents**

| <b>Customer Information</b>   | <b>Contract Information</b>   | <b>Competition</b>  |
|---|---|---|
| <b>SNG</b><br>Approximately 260 firm and interruptible customers.   | Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately seven years. | SNG faces competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on SNG's system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. SNG's four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of their other customers. In addition, SNG competes with pipelines and gathering systems for connection to new supply sources. |
| Major Customers:<br>Atlanta Gas Light Company <sup>(1)</sup><br>(979 BBtu/d)<br>(84 BBtu/d)   | Expire in 2013-2015.<br>Expires in 2024.  |   |
| Southern Company Services<br>(43 BBtu/d)<br>(390 BBtu/d)<br>(375 BBtu/d)  | Expire in 2011-2013.<br>Expire in 2017-2018.<br>Expires in 2032.  |   |
| Alabama Gas Corporation<br>(352 BBtu/d)   | Expires in 2013.  |   |
| SCANA Corporation<br>(315 BBtu/d)   | Expire in 2013-2019.  |   |
| <sup>(1)</sup> Atlanta Gas Light Company releases on a monthly basis a significant portion of its firm capacity to a subsidiary of SCANA Corporation. |   |   |

**Table of Contents**

| <b>Customer Information</b>                         | <b>Contract Information</b>   | <b>Competition</b>   |
|---|---|--|
| <b>CIG</b>  |   |  |
| Approximately 110 firm and interruptible customers. | Approximately 160 firm transportation contracts. Weighted average remaining contract term of approximately seven 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  |   |  |
| (905 BBtu/d)  | Expire in 2012-2019.  |  |
| (874 BBtu/d)  | Expire in 2025-2029.  |  |
| Williams Gas Marketing, Inc.                        |   |  |
| (395 BBtu/d)  | Expire in 2011-2014.  |  |
| Pioneer Natural Resources USA, Inc.                 |   |  |
| (109 BBtu/d)  | Expire in 2014-2015.  |  |
| (202 BBtu/d)  | Expire in 2020-2022.  |  |

**Table of Contents**

| <b>Customer Information</b>                       | <b>Contract Information</b>  | <b>Competition</b>  |
|---|--|---|
| <b>WIC</b>  |  |   |
| Approximately 50 firm and interruptible customers | Approximately 60 firm transportation contracts. Weighted average remaining contract term of approximately seven 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.   |   |
| (414 BBtu/d)                                      | Expire in 2017-2018.   |   |
| (610 BBtu/d)                                      | Expire in 2019-2021.   |   |
| Anadarko Petroleum Corporation                    |  |   |
| (323 BBtu/d)                                      | Expire in 2011-2015.   |   |
| (406 BBtu/d)                                      | Expire in 2016-2018.   |   |
| (665 BBtu/d)                                      | Expire in 2020-2023.   |   |
| <b>Elba Express</b>                               |  |   |
| Four firm and interruptible customers             | One firm transportation contract. Remaining contract term of approximately 29 years.                                   | Elba Express competes for receipts into its system within the worldwide LNG market given its existing configuration to provide south to north takeaway capacity from the Elba LNG terminal to downstream markets in the mid-Atlantic and northeast.   |
| Major Customer:                                   |  |   |
| Shell NA LNG LLC                                  |  |   |
| (965 BBtu/d)                                      | Expires in 2040.   |   |
| <b>SLNG</b>                                       |  |   |
| 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                              | Expires in 2027.   |   |
| Shell NA LNG LLC                                  | Expire in 2035 - 2036.   |   |

**Table of Contents**

*Regulatory Environment*

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves tariffs that establish rates, cost recovery mechanisms, and other terms and conditions of service to our customers. The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital. The FERC's authority also extends to:

rates and charges for natural gas transportation, storage and related services;

certification and construction of new facilities;

extension or abandonment of services and facilities;

maintenance of accounts and records;

relationships between pipelines and certain affiliates;

terms and conditions of service;

depreciation and amortization policies;

acquisition and disposition of facilities; and

initiation and discontinuation of services.

Our interstate pipeline systems are also subject to federal, state and local safety and environmental statutes and regulations of the U.S. Department of Transportation and the U.S. Department of the Interior. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements and we believe that our systems are in material compliance with the applicable regulations.

**Table of Contents**

**Exploration and Production Segment**

Our Exploration and Production segment's business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the U.S., Brazil and Egypt. We currently operate through three divisions in the U.S.: Central, Western and Gulf Coast. During 2010, in the U.S., we focused on several core programs: the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont fractured tight sands in Utah. We also established a new core oil program in the Wolfcamp Shale, which is located in the Permian Basin of West Texas. Over the past few years, we have high-graded our inventory of 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 inventory has become more domestic, lower-risk and with an increased weighting toward oil-focused opportunities. As of December 31, 2010, we controlled approximately 3.7 million net leasehold acres and had proved natural gas and oil reserves of approximately 3.4 Tcfe, including 0.2 Tcfe of proved natural gas and oil reserves related to Four Star, our unconsolidated affiliate. During 2010, daily equivalent natural gas production averaged approximately 782 MMcfe/d, including 62 MMcfe/d from our equity interest in Four Star.

**Table of Contents****U.S.**

*Central.* The Central division includes operations that are primarily focused on shale gas, tight gas sands, coal bed methane and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this division. During 2010, we invested \$475 million on capital projects and production averaged 328 MMcfe/d. The principal operating areas are listed below:

| <b>Area</b>                            | <b>Description</b>   | <b>Net Acres</b> | <b>2010 Capital Investment (In millions)</b> | <b>Average Production (MMcfe/d)</b> |
|--|--|------------------|--|-------------------------------------|
| Haynesville                            | The Haynesville Shale is one of our core programs with shale gas production primarily from the Haynesville but also the Bossier Shale. Production continues to increase as a result of our drilling and completion program. Our operations are primarily in the Holly, Bethany Longstreet and Logansport fields.   | 46,000           | \$ 382                                       | 143                                 |
| East Texas/ North Louisiana (Arklatex) | Land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. Our operations are primarily in the Bear Creek, Holly, Bethany Longstreet and Logansport, Minden and Bald Prairie fields. In December 2010, we sold our natural gas producing properties in Mississippi and retained a land position.   | 165,000          | \$ 59  | 104                                 |
| Shallow/ Unconventional                | Established shallow coal bed methane producing areas in the Black Warrior Basin in Alabama and the Arkoma Basin in Oklahoma. Production is from vertical wells in Alabama and horizontal wells in the Hartshorne Coals in Oklahoma. We have high average working interests and have been developing our operated Shallow Unconventional properties. In addition, we have a 50 percent average working interest covering approximately 46,000 net acres operated by Black Warrior Methane Corporation which produces from the Brookwood Field. We also have approximately 207,000 net acres in the Illinois Basin, focused on the development of the New Albany Shale in southwestern Indiana. We are the operator of these properties and have a 95 percent working interest in this area. | 432,000          | \$ 34  | 81                                  |

**Table of Contents**

*Western.* The Western division includes operations that are primarily focused on natural gas and oil production from coal bed methane, shale gas and lower risk conventional producing areas. We have a large inventory of drilling prospects in this division. Our core program is the Altamont-Bluebell-Cedar Rim Field, referred to as Altamont. During 2010, we invested \$181 million on capital projects and production averaged 160 MMcfe/d. The principal operating areas are listed below:

| Area                         | Description  | Net<br>Acres | 2010<br>Capital<br>Investment<br>(In<br>millions) | Average<br>Production<br>(MMcfe/d) |
|------------------------------|--|--------------|---|------------------------------------|
| Uintah Basin                 | Primarily focused on vertical fractured oil production in Altamont in Utah.  | 190,000      | \$ 149  | 51                                 |
| Raton Basin                  | Primarily focused on coal bed methane production in the Raton Basin of northern New Mexico and southern Colorado where we own the minerals beneath the Vermejo Park Ranch.   | 605,000      | \$ 16   | 76                                 |
| Rocky Mountains<br>(Rockies) | Primarily in Wyoming with a focus in the Powder River basin, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with a non-operated working interest in the County Line coal bed methane unit. | 242,000      | \$ 16   | 33                                 |

**Table of Contents**

*Gulf Coast.* We focus primarily on developing and exploring for natural gas and oil in unconventional shales and tight gas sands in south Texas and the upper Gulf Coast that are characterized by lower risk, longer life production profiles. We also have operations in Gulf of Mexico and south Louisiana focused on deeper conventional reservoirs characterized by relatively high initial production rates, resulting in higher near-term cash flows and high decline rates. Our core programs are the Eagle Ford Shale and the emerging Wolfcamp Shale. The Eagle Ford oil program is the most economic of our portfolio with approximately 60 percent of total net acres located in the liquids rich area. We grew our Wolfcamp Shale position in the Permian Basin to approximately 138,000 acres. During 2010, we invested \$540 million on capital projects, including approximately \$265 million for the acquisition of leases in the Eagle Ford and Wolfcamp oil shale programs, and production averaged 199 MMcfe/d in the Gulf Coast division. The principal operating areas are listed below:

| <b>Area</b>                        | <b>Description</b>   | <b>Net Acres</b> | <b>2010 Capital Investment (In millions)</b> | <b>Average Production (MMcfe/d)</b> |
|------------------------------------|--|------------------|--|-------------------------------------|
| Upper Texas<br>Gulf Coast          | Includes our position in the Eagle Ford Shale, located in Webb, LaSalle, Frio and Atascosa counties, where we have approximately 170,000 net acres as of December 31, 2010. 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.   | 287,000          | \$ 239                                       | 24                                  |
| South Texas                        | Includes the Wolfcamp Shale in the Permian Basin in Reagan, Crockett, Upton and Irion counties in Texas, and 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 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. | 213,000          | \$ 232                                       | 97                                  |
| Gulf of Mexico/<br>South Louisiana | 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) natural gas and oil 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. South Louisiana area also includes interests in Beauregard and Vermilion Parishes.   | 261,000          | \$ 69  | 78                                  |

*Unconsolidated Affiliate Four Star.* We have an approximate 49 percent equity interest in Four Star. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama basins and in the Gulf of Mexico. During 2010, our equity interest in Four Star's daily equivalent natural gas production averaged approximately 62 MMcfe/d.

**Table of Contents****International**

*Brazil.* Our Brazilian operations cover approximately 137,000 net acres in Camamu, Espirito Santo and Potiguar basins located offshore Brazil. During 2010, we invested \$66 million on capital projects in Brazil and production averaged 33 MMcfe/d. As of December 31, 2010 we have total capitalized costs of approximately \$371 million, of which \$182 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 Camarao and Pinauna Fields. In Pinauna, we are continuing the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development. We have experienced delays in this process during both 2009 and 2010 for a number of reasons, including the Gulf of Mexico oil spill and Brazilian elections. Our ability to develop this area is dependent on the receipt of all required regulatory approvals. We have filed the required environmental reports with the Brazilian environmental agency, continue to address the agency's technical questions and expect to receive a decision on our preliminary license request during late 2011. As of December 31, 2010 we have \$94 million of unevaluated capitalized costs related to the Pinauna development.

We own an 18 percent working interest in a development area, formerly part of the BM-CAL-5 block, operated by Petrobras, Brazil's state-owned energy company. In 2008, we drilled an exploratory well, and continue to search for viable commercial options to develop the resources found. In addition, we continue to own a 20 percent interest in two additional blocks in the Camamu Basin, CAL-M-312 and CAL-M-372, which are located east of and contiguous to the BM-CAL-5 block.

*Espirito Santo Basin.* We own an approximate 24 percent working interest in the Camarupim Field. During 2010 we began production from the second and third wells of a four well development program. Our production from these wells averaged approximately 25 MMcfe/d in 2010. We continue to work with Petrobras to connect the fourth well and anticipate bringing the well on production during 2011.

In 2010, we participated with Petrobras in drilling a second exploratory well in the ES-5 block in the Espirito Santo Basin in which we own a 35 percent working interest. Hydrocarbons were found in the well and we are now evaluating the results. The exploratory well is located adjacent to the Camarupim Field and we anticipate testing the well in 2011. We also continue to evaluate the results of another exploratory well located to the north of Camarupim Field where drilling was completed in 2009 and hydrocarbons were found. As of December 31, 2010 we have \$81 million of unevaluated capitalized costs related to our ES-5 block.

*Potiguar Basin.* We own a 35 percent working interest in the Pescada-Arabaiana Fields. Our production from these fields averaged approximately 8 MMcfe/d in 2010.

*Egypt.* As of December 31, 2010, our Egyptian operations cover approximately 1.1 million net acres in three blocks located onshore in Egypt's Western Desert. During 2010, we invested \$20 million on capital projects in Egypt. We own a 60 percent working interest in the South Mariut block, which contains approximately 500,000 net acres. There was no drilling activity on this block in 2010, however we shot 3-D seismic and anticipate drilling an exploratory well in 2011. We also own a 50 percent working interest in the South Alamein block, which contains approximately 300,000 net acres, on which we drilled two wells in 2010. The wells encountered oil shows but were temporarily plugged as we continue to evaluate the results. Finally, we own a 40 percent working interest in the Tanta block, which contains approximately 300,000 net acres. During 2010, we drilled one unsuccessful well on this block. In 2011, we relinquished the block. As of December 31, 2010 we have total capitalized costs in Egypt of approximately \$66 million, all of which are unevaluated.

**Table of Contents****Natural Gas and Oil Properties***Natural Gas, Oil and Condensate and NGL Reserves and Production*

The table below presents information about our estimated proved reserves as of December 31, 2010. These reserves are based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The risks and uncertainties associated with estimating proved natural gas and oil reserves are discussed further in Item 1A, Risk Factors. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2010.

|  | Net Proved Reserves   |                           |                | Total<br>(MMcfe)         | Total<br>(Percent) | 2010<br>Production<br>(MMcfe) |
|--|-----------------------|---------------------------|----------------|--------------------------|--------------------|-------------------------------|
|  | Natural Gas<br>(MMcf) | Oil/Condensate<br>(MBbls) | NGL<br>(MBbls) |                          |                    |                               |
| <i>Reserves and<br/>Production by Division</i> |                       |                           |                |                          |                    |                               |
| Consolidated:                                  |                       |                           |                |                          |                    |                               |
| Proved   |                       |                           |                |                          |                    |                               |
| U.S.   |                       |                           |                |                          |                    |                               |
| Central  | 1,328,636             | 908                       |                | 1,334,084                | 40%                | 119,846                       |
| Western  | 702,472               | 68,702                    | 1              | 1,114,690                | 33%                | 58,307                        |
| Gulf Coast                                     | 364,285               | 33,630                    | 9,050          | 620,365                  | 18%                | 72,468                        |
| Total  | 2,395,393             | 103,240                   | 9,051          | 3,069,139                | 91%                | 250,621                       |
| Brazil   | 85,219                | 2,654                     |                | 101,143                  | 3%                 | 12,010                        |
| Total Consolidated                             | 2,480,612             | 105,894                   | 9,051          | 3,170,282                | 94%                | 262,631                       |
| Unconsolidated                                 |                       |                           |                |                          |                    |                               |
| Affiliate <sup>(1)</sup>                       | 155,031               | 1,623                     | 4,458          | 191,518                  | 6%                 | 22,787                        |
| Total Combined                                 | 2,635,643             | 107,517                   | 13,509         | 3,361,800                | 100%               | 285,418                       |
| <i>Reserves by<br/>Classification</i>          |                       |                           |                |                          |                    |                               |
| Consolidated:                                  |                       |                           |                |                          |                    |                               |
| Proved Developed                               |                       |                           |                |                          |                    |                               |
| U.S.   |                       |                           |                |                          |                    |                               |
| U.S.   | 1,558,892             | 38,278                    | 6,096          | 1,825,136                | 57%                |                               |
| Brazil   | 75,171                | 2,403                     |                | 89,589                   | 3%                 |                               |
| Total  | 1,634,063             | 40,681                    | 6,096          | 1,914,725 <sup>(2)</sup> | 60%                |                               |
| Proved Undeveloped                             |                       |                           |                |                          |                    |                               |
| U.S.   |                       |                           |                |                          |                    |                               |
| U.S.   | 836,501               | 64,962                    | 2,955          | 1,244,003                | 40%                |                               |
| Brazil   | 10,048                | 251                       |                | 11,554                   | %                  |                               |
| Total  | 846,549               | 65,213                    | 2,955          | 1,255,557                | 40%                |                               |
| Total Consolidated                             | 2,480,612             | 105,894                   | 9,051          | 3,170,282 <sup>(2)</sup> | 100%               |                               |

|  |           |         |        |           |      |
|--|-----------|---------|--------|-----------|------|
| Unconsolidated<br>Affiliate <sup>(1)</sup> : |           |         |        |           |      |
| Proved Developed                             | 128,862   | 1,574   | 3,483  | 159,204   | 83%  |
| Proved Undeveloped                           | 26,169    | 49      | 975    | 32,314    | 17%  |
| Unconsolidated<br>Affiliate <sup>(1)</sup>   | 155,031   | 1,623   | 4,458  | 191,518   | 100% |
| Total Combined                               | 2,635,643 | 107,517 | 13,509 | 3,361,800 | 100% |

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

(2) Includes 1,518 Bcfe of proved developed producing reserves representing 48 percent of consolidated proved reserves and 397 Bcfe of proved developed non-producing reserves representing 12 percent of consolidated proved reserves at December 31, 2010.

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.

**Table of Contents**

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, 2010.

|  | <b>Net Proved<br/>Reserves<br/>(MMcfe)</b> |
|--|--|
| As Reported                                  |  |
| Consolidated                                 | 3,170,282                                  |
| Unconsolidated Affiliate                     | 191,518                                    |
| <b>Total Combined</b>                        | <b>3,361,800</b>                           |
| <br>   |  |
| 10 percent increase in prices <sup>(1)</sup> |  |
| Consolidated                                 | 3,212,329                                  |
| Unconsolidated Affiliate                     | 195,125                                    |
| <b>Total Combined</b>                        | <b>3,407,454</b>                           |
| <br>   |  |
| 10 percent decrease in prices <sup>(1)</sup> |  |
| Consolidated                                 | 3,114,897                                  |
| Unconsolidated Affiliate                     | 186,260                                    |
| <b>Total Combined</b>                        | <b>3,301,157</b>                           |

<sup>(1)</sup> Based on the first day 12-month average U.S natural gas and oil prices we used to determine proved reserves at December 31, 2010.

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare for Four Star, our unconsolidated affiliate, has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is currently responsible for reserve reporting, strategy development, technical excellence and land administration. He has over 23 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.

**Table of Contents**

Ryder Scott Company, L.P. (Ryder Scott) conducted an audit of the estimates of proved reserves prepared by us as of December 31, 2010. 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 88 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, 2010. In connection with the audit of these proved reserves, Ryder Scott reviewed 86 percent of the properties associated with Four Star's total proved reserves on a natural gas equivalent basis, representing 86 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 Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has over 19 years of reservoir engineering experience. His technical expertise is in the area of economic evaluations, reserves management systems, probabilistic modeling, pressure transient analysis, reservoir surveillance, production optimization, field operations, Enhanced Oil Recovery certification, computer application development and database management.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as they are produced. Recovery of proved undeveloped (PUD) reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of PUD reserves and proved non-producing reserves are inherently subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

We assess our PUD reserves on a quarterly basis. At December 31, 2010, we had 1,256 Bcfe of consolidated PUD reserves representing an increase of 420 Bcfe of PUD reserves compared to December 31, 2009. During 2010, we added 488 Bcfe of PUD reserves primarily due to our drilling activities in the Haynesville Shale in our Central division and the Eagle Ford Shale in our Gulf Coast division. In addition, we acquired 37 Bcfe of PUD reserves, of which 12 Bcfe occurred from the acquisition of oil properties in the Wolfcamp Shale in west Texas, in our Gulf Coast division. We had negative revisions of 3 Bcfe of PUD reserves, consisting of a negative revision of 33 Bcfe related to reserves older than five years, offset by a positive revision of 30 Bcfe related to prices and performance.

We spent approximately \$199 million, \$186 million and \$141 million, during 2010, 2009 and 2008, respectively, to convert approximately 11 percent or 94 Bcfe, 11 percent or 69 Bcfe and 16 percent or 95 Bcfe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2010 reserve report, the amounts estimated to be spent in 2011, 2012 and 2013 to develop our consolidated worldwide PUD reserves are \$597 million, \$616 million and \$512 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 product prices.

Of the 1,256 Bcfe of PUD reserves at December 31, 2010, we have 62 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. We have exclusive development rights in the Raton Basin with long term leases which enables us to develop beyond the five-year window. We have historical and ongoing drilling and development activities in this area, including a 25 to 30 well development program in 2011. There were no new PUD reserves booked to the Raton Basin in 2010, and the undeveloped reserves outside of our current five-year development plan represent less than five percent of the consolidated PUD reserves.

**Table of Contents***Acreage and Wells*

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2010, (ii) our interest in natural gas and oil wells at December 31, 2010 and (iii) our exploratory and development wells drilled during the years 2008 through 2010. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

|                     | <b>Developed</b>           |                          | <b>Undeveloped</b>         |                          | <b>Total</b>               |                          |
|---------------------|----------------------------|--------------------------|----------------------------|--------------------------|----------------------------|--------------------------|
|                     | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)</sup></b> | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)</sup></b> | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)</sup></b> |
| <i>Acreage</i>      |                            |                          |                            |                          |                            |                          |
| United States       |                            |                          |                            |                          |                            |                          |
| Central             | 373,150                    | 260,354                  | 502,334                    | 382,585                  | 875,484                    | 642,939                  |
| Western             | 395,281                    | 314,094                  | 936,076                    | 723,185                  | 1,331,357                  | 1,037,279                |
| Gulf Coast          | 316,468                    | 180,340                  | 666,273                    | 581,182                  | 982,741                    | 761,522                  |
| Total United States | 1,084,899                  | 754,788                  | 2,104,683                  | 1,686,952                | 3,189,582                  | 2,441,740                |
| Brazil              | 47,377                     | 14,492                   | 487,022                    | 122,182                  | 534,399                    | 136,674                  |
| Egypt               |                            |                          | 2,201,004                  | 1,101,454                | 2,201,004                  | 1,101,454                |
| Worldwide Total     | 1,132,276                  | 769,280                  | 4,792,709                  | 2,910,588                | 5,924,985                  | 3,679,868                |

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

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

In the United States, our net developed acreage is concentrated primarily in Utah (18 percent), New Mexico (17 percent), Texas (14 percent), Louisiana (10 percent), Oklahoma (9 percent) and Alabama (9 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (26 percent), Texas (21 percent), Indiana (11 percent), the Gulf of Mexico (10 percent), Colorado (7 percent) and Wyoming (6 percent). Approximately 10 percent, 6 percent and 21 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2011, 2012 and 2013, respectively. Approximately 10 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012. Approximately 11 percent and 19 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 extending lease terms, drilling the acreage ourselves, or by entering into farm-out agreements with other operators.

|               | <b>Natural Gas</b>         |                          | <b>Oil</b>                 |                          | <b>Total</b>               |                             | <b>Wells Being Drilled at December 31, 2010</b> |                          |
|---------------|----------------------------|--------------------------|----------------------------|--------------------------|----------------------------|-----------------------------|---|--------------------------|
|               | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)</sup></b> | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)</sup></b> | <b>Gross<sup>(1)</sup></b> | <b>Net<sup>(2)(3)</sup></b> | <b>Gross<sup>(1)</sup></b>                      | <b>Net<sup>(2)</sup></b> |
|               | <i>Productive Wells</i>    |                          |                            |                          |                            |                             |   |                          |
| United States |                            |                          |                            |                          |                            |                             |   |                          |
| Central       | 3,698                      | 2,116                    | 17                         | 6                        | 3,715                      | 2,122                       | 23  | 9                        |
| Western       | 1,398                      | 1,024                    | 593                        | 517                      | 1,991                      | 1,541                       | 2   | 2                        |
| Gulf Coast    | 1,006                      | 804                      | 46                         | 36                       | 1,052                      | 840                         | 10  | 10                       |
| Total         | 6,102                      | 3,944                    | 656                        | 559                      | 6,758                      | 4,503                       | 35  | 21                       |
| Brazil        | 9                          | 2                        | 5                          | 2                        | 14                         | 4                           | 2   | 1                        |

|                  |       |       |     |     |       |       |    |    |
|------------------|-------|-------|-----|-----|-------|-------|----|----|
| Egypt            |       |       |     |     |       |       | 4  | 2  |
| Worldwide Total. | 6,111 | 3,946 | 661 | 561 | 6,772 | 4,507 | 41 | 24 |

- (1) Gross interest reflects the total wells we participated in, regardless of our ownership interest.
- (2) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.
- (3) At December 31, 2010, we operated 4,057 of the 4,507 net productive wells.

**Table of Contents**

|                      | Net Exploratory <sup>(1)</sup> |      |      | Net Development <sup>(1)</sup> |      |      |
|----------------------|--------------------------------|------|------|--------------------------------|------|------|
|                      | 2010                           | 2009 | 2008 | 2010                           | 2009 | 2008 |
| <i>Wells Drilled</i> |                                |      |      |                                |      |      |
| United States        |                                |      |      |                                |      |      |
| Productive           | 35                             | 61   | 163  | 55                             | 69   | 278  |
| Dry                  |                                | 2    | 2    | 2                              | 2    | 7    |
| Total                | 35                             | 63   | 165  | 57                             | 71   | 285  |
| Brazil               |                                |      |      |                                |      |      |
| Productive           |                                |      |      |                                | 1    |      |
| Dry                  |                                |      |      |                                |      |      |
| Total                |                                |      |      |                                | 1    |      |
| Egypt                |                                |      |      |                                |      |      |
| Productive           |                                |      |      |                                |      |      |
| Dry                  |                                | 2    |      |                                |      |      |
| Total                |                                | 2    |      |                                |      |      |
| Worldwide            |                                |      |      |                                |      |      |
| Productive           | 35                             | 61   | 163  | 55                             | 70   | 278  |
| Dry                  |                                | 4    | 2    | 2                              | 2    | 7    |
| Total                | 35                             | 65   | 165  | 57                             | 72   | 285  |

(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 natural gas and oil that may ultimately be recovered.

*Net Production, Sales Prices, Transportation and Production Costs*

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

|                                     | 2010    | 2009    | 2008    |
|-------------------------------------|---------|---------|---------|
| <i>Volumes:</i>                     |         |         |         |
| Consolidated Net Production Volumes |         |         |         |
| United States                       |         |         |         |
| Natural gas (MMcf)                  | 215,905 | 214,718 | 229,518 |
| Oil, condensate and NGL (MBbls)     | 5,786   | 5,548   | 6,371   |
| Total (MMcfe)                       | 250,621 | 248,006 | 267,745 |
| Brazil                              |         |         |         |
| Natural gas (MMcf)                  | 9,706   | 3,826   | 3,185   |
| Oil, condensate and NGL (MBbls)     | 384     | 100     | 124     |

Edgar Filing: EL PASO CORP/DE - Form 10-K

|   |         |         |         |
|---|---------|---------|---------|
| Total (MMcfe)                                   | 12,010  | 4,426   | 3,928   |
| Consolidated Worldwide                          |         |         |         |
| Natural gas (MMcf)                              | 225,611 | 218,544 | 232,703 |
| Oil, condensate and NGL (MBbls)                 | 6,170   | 5,648   | 6,495   |
| Total (MMcfe)                                   | 262,631 | 252,432 | 271,673 |
| Total (MMcfe/d)                                 | 720     | 691     | 742     |
| Unconsolidated Affiliate Volumes <sup>(1)</sup> |         |         |         |
| Natural gas (MMcf)                              | 17,165  | 19,557  | 20,576  |
| Oil, condensate and NGL (MBbls)                 | 937     | 1,097   | 1,054   |
| Total equivalent volumes (MMcfe)                | 22,787  | 26,139  | 26,899  |
| MMcfe/d   | 62      | 72      | 74      |
| Total Combined Volumes <sup>(1)</sup>           |         |         |         |
| Natural gas (MMcf)                              | 242,776 | 238,101 | 253,279 |
| Oil, condensate and NGL (MBbls)                 | 7,107   | 6,745   | 7,549   |
| Total equivalent volumes (MMcfe)                | 285,418 | 278,571 | 298,572 |
| MMcfe/d   | 782     | 763     | 816     |

**Table of Contents**

|   | <b>2010</b> | <b>2009</b> | <b>2008</b> |
|---|-------------|-------------|-------------|
| <i>Consolidated Prices and Costs per Unit:</i>                |             |             |             |
| Natural Gas Average Realized Sales Price (\$/Mcf)             |             |             |             |
| United States   |             |             |             |
| Physical sales  | \$ 4.26     | \$ 3.78     | \$ 8.51     |
| Including financial derivative settlements                    | \$ 5.71     | \$ 7.68     | \$ 8.26     |
| Brazil  |             |             |             |
| Physical sales  | \$ 5.65     | \$ 4.84     | \$ 2.60     |
| Including financial derivative settlements                    | \$ 4.93     | \$ 4.22     | \$ 2.60     |
| Worldwide   |             |             |             |
| Physical sales  | \$ 4.32     | \$ 3.80     | \$ 8.43     |
| Including financial derivative settlements <sup>(2)</sup>     | \$ 5.67     | \$ 7.62     | \$ 8.18     |
| Oil, Condensate and NGL Average Realized Sales Price (\$/Bbl) |             |             |             |
| United States   |             |             |             |
| Physical sales  | \$64.99     | \$47.03     | \$82.96     |
| Including financial derivative settlements                    | \$63.60     | \$78.70     | \$77.42     |
| Brazil  |             |             |             |
| Physical sales  | \$78.02     | \$60.88     | \$96.21     |
| Including financial derivative settlements                    | \$78.02     | \$60.88     | \$96.21     |
| Worldwide   |             |             |             |
| Physical sales  | \$65.80     | \$47.27     | \$83.21     |
| Including financial derivative settlements <sup>(2)</sup>     | \$64.50     | \$78.38     | \$77.78     |
| Average Transportation Costs                                  |             |             |             |
| United States   |             |             |             |
| Natural gas (\$/Mcf)  | \$ 0.31     | \$ 0.28     | \$ 0.32     |
| Oil, condensate and NGL (\$/Bbl)                              | \$ 0.84     | \$ 0.78     | \$ 0.98     |
| Worldwide   |             |             |             |
| Natural gas (\$/Mcf)  | \$ 0.30     | \$ 0.28     | \$ 0.31     |
| Oil, condensate and NGL (\$/Bbl)                              | \$ 0.79     | \$ 0.77     | \$ 0.96     |
| Average Production Costs (\$/Mcf)                             |             |             |             |
| United States   |             |             |             |
| Lease operating expenses                                      | \$ 0.62     | \$ 0.70     | \$ 0.89     |
| Production taxes  | 0.21        | 0.21        | 0.44        |
| Total production costs  | \$ 0.83     | \$ 0.91     | \$ 1.33     |
| Brazil  |             |             |             |
| Lease operating expenses <sup>(3)</sup>                       | \$ 3.07     | \$ 5.19     | \$ 1.64     |
| Production taxes  | 0.73        | 0.68        | 0.58        |
| Total production costs  | \$ 3.80     | \$ 5.87     | \$ 2.22     |
| Worldwide   |             |             |             |
| Lease operating expenses <sup>(3)</sup>                       | \$ 0.73     | \$ 0.78     | \$ 0.90     |
| Production taxes  | 0.27        | 0.22        | 0.44        |
| Total production costs  | \$ 1.00     | \$ 1.00     | \$ 1.34     |

- (1) Represents our approximate 49 percent equity interest in the volumes of Four Star.
- (2) Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were \$157 million. Had we included these premiums in our natural gas average realized prices in 2010, our realized price, including financial derivatives settlements, would have decreased by \$0.70/Mcf for the year ended December 31, 2010. Premiums related to natural gas derivatives settled during the year ended December 31, 2008 were \$21 million. Had we included these premiums in our natural gas average realized prices in 2008, our realized price, including financial derivative settlements, would have decreased by \$0.09/Mcf for the year ended December 31, 2008. We had no premiums related to natural gas derivatives settled during the year ended December 31, 2009, or related to oil derivatives settled during the years ended December 31, 2010, 2009 and 2008.
- (3) Includes approximately \$14 million of start-up costs in Camarupim Field in 2009 or \$3.08 per Mcfe for Brazil and \$0.05 per Mcfe worldwide.

**Table of Contents***Acquisition, Development and Exploration Expenditures*

The following table details information regarding the costs incurred in our acquisition, development and exploration activities for each of the three years ended December 31:

|                                      | 2010     | 2009<br>(In millions) | 2008     |
|--------------------------------------|----------|-----------------------|----------|
| United States                        |          |                       |          |
| Acquisition Costs:                   |          |                       |          |
| Proved                               | \$ 51    | \$ 87                 | \$ 51    |
| Unproved                             | 269      | 89                    | 74       |
| Development Costs                    | 276      | 324                   | 938      |
| Exploration Costs:                   |          |                       |          |
| Delay rentals                        | 9        | 5                     | 6        |
| Seismic acquisition and reprocessing | 15       | 27                    | 24       |
| Drilling                             | 576      | 323                   | 408      |
| Asset Retirement Obligations         | 7        | 36                    | 19       |
| Total full cost pool expenditures    | 1,203    | 891                   | 1,520    |
| Non-full cost pool expenditures      | 35       | 34                    | 30       |
| Total costs incurred                 | \$ 1,238 | \$ 925                | \$ 1,550 |
| Brazil and Egypt <sup>(1)</sup>      |          |                       |          |
| Acquisition Costs:                   |          |                       |          |
| Unproved                             | \$       | \$ 51                 | \$ 1     |
| Development Costs                    | 28       | 118                   | 93       |
| Exploration Costs:                   |          |                       |          |
| Seismic acquisition and reprocessing | 6        | 3                     | 13       |
| Drilling                             | 52       | 64                    | 91       |
| Asset Retirement Obligations         |          | 6                     |          |
| Total full cost pool expenditures    | 86       | 242                   | 198      |
| Non-full cost pool expenditures      | 1        | 4                     | 13       |
| Total costs incurred                 | \$ 87    | \$ 246                | \$ 211   |
| Worldwide <sup>(1)</sup>             |          |                       |          |
| Acquisition Costs:                   |          |                       |          |
| Proved                               | \$ 51    | \$ 87                 | \$ 51    |
| Unproved                             | 269      | 140                   | 75       |
| Development Costs                    | 304      | 442                   | 1,031    |
| Exploration Costs:                   |          |                       |          |
| Delay rentals                        | 9        | 5                     | 6        |
| Seismic acquisition and reprocessing | 21       | 30                    | 37       |
| Drilling                             | 628      | 387                   | 499      |
| Asset Retirement Obligations         | 7        | 42                    | 19       |
| Total full cost pool expenditures    | 1,289    | 1,133                 | 1,718    |
| Non-full cost pool expenditures      | 36       | 38                    | 43       |

|                      |          |          |          |
|----------------------|----------|----------|----------|
| Total costs incurred | \$ 1,325 | \$ 1,171 | \$ 1,761 |
|----------------------|----------|----------|----------|

(1) Costs incurred for Egypt were \$20 million, \$81 million and \$27 million for the years ended December 31, 2010, 2009 and 2008.

27

---

**Table of Contents**

*Markets and Competition*

We primarily sell our domestic natural gas and oil to third parties through our Marketing segment at spot market prices, subject to customary adjustments. We sell our NGL at market prices under monthly or long-term contracts, subject to customary adjustments. In Brazil, we sell the majority of our natural gas and oil, under long-term contracts to Petrobras. These long-term contracts include a gas sales agreement and a condensate sales agreement. The gas sales agreement provides for a price that adjusts quarterly based on a basket of fuel oil prices, while the condensate sales agreement provides for a price that adjusts monthly based on a Brent crude price less a fixed differential that will adjust annually. We enter into derivative contracts on our natural gas and oil production to stabilize our cash flows, reduce the risk and financial impact of downward commodity price movements and protect the economic assumptions associated with our capital investment programs. For a further discussion of these contracts, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

The exploration and production business is highly competitive in the search for and acquisition of additional natural gas and oil reserves and in the sale of natural gas, oil and NGL. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms, our ability to access drilling, 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 natural gas and oil exploration and production activities are regulated at the federal, state and local levels, in the United States, Brazil and Egypt. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to various governmental safety and environmental regulations in the jurisdictions in which we operate.

Our domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the 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.

**Table of Contents****Marketing Segment**

Our Marketing segment's primary focus is to market our Exploration and Production segment's natural gas and oil production, and to manage El Paso's overall price risk. In addition, we continue to manage and liquidate remaining legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2010, we managed the following types of contracts:

*Natural gas transportation-related contracts.* Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the 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, 2010:

|                                  | <b>Affiliated Pipelines<sup>(1)</sup></b> | <b>Other Pipelines</b> |
|----------------------------------|---|------------------------|
| Daily capacity (MMBtu/d)         | 526,000                                   | 253,000                |
| Expiration                       | 2011 to 2028                              | 2011 to 2026           |
| Receipt points / Delivery points | Various                                   | Various                |

<sup>(1)</sup> Primarily consists of contracts with TGP and EPNG.

*Legacy natural gas and power contracts.* As of December 31, 2010, we had several physical natural gas contracts with power plants associated with our legacy trading activities. These contracts obligate us to sell 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-related 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. These contracts require us to provide approximately 1,700 GWh of power per year and approximately 71 GW of installed capacity per year in the PJM power pool through April 2016. 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).

**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 21, 2011, we had 4,937 full-time employees, of which 91 employees are subject to collective bargaining arrangements.

**Table of Contents****Executive Officers of the Registrant**

Our executive officers as of February 25, 2011, are listed below.

| <b>Name</b>         | <b>Office</b>   | <b>Officer Since</b> | <b>Age</b> |
|---------------------|---|----------------------|------------|
| Douglas L. Foshee   | Chairman, President and Chief Executive Officer of El Paso                                    | 2003                 | 51         |
| John R. Sult        | Executive Vice President and Chief Financial Officer of El Paso                               | 2005                 | 51         |
| Brent J. Smolik     | Executive Vice President of El Paso and President of El Paso Exploration & Production Company | 2006                 | 49         |
| James C. Yardley    | Executive Vice President, Pipeline Group  | 2005                 | 59         |
| D. Mark Leland      | Executive Vice President of El Paso and President of Midstream Group                          | 2005                 | 49         |
| Robert W. Baker     | Executive Vice President and General Counsel of El Paso                                       | 2002                 | 54         |
| Susan B. Ortenstone | Executive Vice President and Chief Administrative Officer of El Paso                          | 2003                 | 54         |
| James J. Cleary     | President of Western Pipeline Group   | 2005                 | 56         |
| Dane E. Whitehead   | Senior Vice President, Strategy and Enterprise Business Development of El Paso                | 2009                 | 49         |

Douglas L. Foshee has been Chairman of the Board of Directors of El Paso Corporation since May 2009 and President, Chief Executive Officer and a director of El Paso since September 2003. Prior to joining El Paso, Mr. Foshee served as Executive Vice President and Chief Operating Officer of Halliburton Company having joined that company in 2001 as Executive Vice President and Chief Financial Officer. Several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, commenced prepackaged Chapter 11 proceedings to discharge current and future asbestos and silica personal injury claims in December 2003 and an order confirming a plan of reorganization became final effective December 31, 2004. Prior to assuming his position at Halliburton, Mr. Foshee served as President, Chief Executive Officer and Chairman of the Board of Nuevo Energy Company and Chief Executive Officer and Chief Operating Officer of Torch Energy Advisors Inc. Mr. Foshee presently serves as a director of Cameron International Corporation, and from January 2009 until February 2010 served as a trustee of AIG Credit Facility Trust. Mr. Foshee also serves on the Board of Trustees of Rice University and serves as a member of the Council of Overseers for the Jesse H. Jones Graduate School of Management. He is a member of various other civic and community organizations. Mr. Foshee also serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

John R. Sult has been Executive Vice President and Chief Financial Officer of El Paso Corporation since March 2010 and Senior Vice President and Chief Financial Officer from November 2009 to March 2010. Mr. Sult previously served as Senior Vice President and Controller of El Paso from November 2005 to November 2009. He has served as Executive Vice President and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. since July 2010, Senior Vice President and Chief Financial Officer from November 2009 to July 2010, and Senior Vice President, Chief Financial Officer and Controller from August 2007 to November 2009. Mr. Sult served as Senior Vice President, Chief Financial Officer and Controller of El Paso's Pipeline Group from November 2005 to November 2009. Mr. Sult was Vice President and Controller for Halliburton Energy Services from August 2004 to October 2005. Mr. Sult also serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

Brent J. Smolik has been Executive Vice President of El Paso Corporation and President of El Paso Exploration & Production Company since November 2006. Mr. Smolik was President of ConocoPhillips Canada from April 2006 to

October 2006. Prior to the Burlington Resources merger with ConocoPhillips, he was President of Burlington Resources Canada from September 2004 to March 2006. From 1990 to 2004, Mr. Smolik worked in various engineering and asset management capacities for Burlington Resources Inc., including the Chief Engineering role from 2000 to 2004. He was a member of the Burlington Executive Committee from 2001 to 2006. Mr. Smolik also serves on the boards of the American Exploration and Production Council, America's Natural Gas Alliance and the Independent Petroleum Association of America.

**Table of Contents**

James C. Yardley has been Executive Vice President of El Paso Corporation with responsibility for the regulated pipeline business unit since August 2006. He has served as Chairman of the Board of Tennessee Gas Pipeline Company since February 2007 and served as its President from August 2006 to August 2010. Mr. Yardley has been Chairman of El Paso Natural Gas Company since August of 2006 and served as President of Southern Natural Gas Company from May 1998 to August 2010. Mr. Yardley has been a member of the Management Committees of both Colorado Interstate Gas Company and Southern Natural Gas Company since their conversion to general partnerships in November 2007. He also serves on the board of Interstate Natural Gas Association of America and previously served as its Chairman. Mr. Yardley serves as Director, President and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

D. Mark Leland has been Executive Vice President of El Paso Corporation and President of El Paso's Midstream business unit since October 2009. Mr. Leland previously served as Executive Vice President and Chief Financial Officer of El Paso from August 2005 to November 2009. He served as Executive Vice President of El Paso Exploration & Production Company from January 2004 to August 2005, and as Chief Financial Officer and a director from April 2004 to August 2005. Mr. Leland served as Senior Vice President and Chief Operating Officer of GulfTerra Energy Partners, L.P. and its general partner from January 2003 to December 2003, and as Senior Vice President and Controller from July 2000 to January 2003. Mr. Leland serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

Robert W. Baker has been Executive Vice President and General Counsel of El Paso Corporation since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. Mr. Baker previously served as Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time, he held various legal positions with El Paso and its subsidiaries, including managing the legal matters associated with telecommunication services, domestic power plant development, and the international energy infrastructure projects. Mr. Baker serves as Executive Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

Susan B. Ortenstone has been Executive Vice President and Chief Administrative Officer of El Paso Corporation since March 2010 and Senior Vice President and Chief Administrative Officer from October 2007 to March 2010. Ms. Ortenstone previously served as Senior Vice President from October 2003 to October 2009. Ms. Ortenstone was Chief Executive Officer for Epic Energy Pty Ltd. from January 2001 to June 2003. Ms. Ortenstone serves as Executive Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

James J. Cleary has been a director and President of El Paso Natural Gas Company since January 2004. Mr. Cleary has been a member of the Management Committee of Colorado Interstate Gas Company since November 2007 and President since January 2004. He previously served as Chairman of the Board of both El Paso Natural Gas Company and Colorado Interstate Gas Company from May 2005 to August 2006. From January 2001 to December 2003, he served as President of ANR Pipeline Company. Mr. Cleary serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

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

**Available Information**

Our website is <http://www.elpaso.com>. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the 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.



**Table of Contents****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 our 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 existing coal-fired power generation that is replaced with natural gas-fired power generation. 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 ability of the Organization of Petroleum Exporting Countries (OPEC) to agree upon and maintain certain production levels, political unrest and changes in foreign governments in producing regions of the world and unexpected wars, terrorist activities and others acts of aggression;

Technological advancements that may drive further increases in production from oil and natural gas shales;

The need of many producers to drill to maintain 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 and alternate fuels;

Increased prices of oil, natural gas or NGLs that could negatively impact the demand for these products;

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.

**Table of Contents**

***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 will remain depressed for sustained periods, especially in relation to natural gas prices which are at relatively low levels at this time. 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) 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.

In addition to negatively impacting our cash flows, prolonged or substantial declines in these commodity prices can negatively impact our estimated proven oil and natural gas reserves which can cause us to incur non-cash charges to earnings. The majority of our proved reserves at December 31, 2010 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.

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

We use futures, over-the-counter options and swaps to mitigate our commodity price, basis, currency 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 inventory of proved reserves and unproved resources.

Most 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. The potential impact of the recent federal legislation

**Table of Contents**

regulating derivative transactions on our collateral posting requirements is not certain at this time and we could be required to post additional collateral as a result of the implementing regulations.

To the extent we enter into derivative contracts to manage our commodity price exposure, basis and interest rate exposures, we 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 in the transportation and storage of natural gas. We also compete with suppliers of alternate sources of energy, including electricity, 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 large 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). There have also been various proposals over time to construct LNG terminals along the east and west coasts that could also negatively impact the demand and the transportation rates that several of our pipeline systems could charge to the extent the LNG terminals were constructed. For example, 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 natural gas and oil 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 new midstream business, we compete with third parties to gather, transport, process, fractionate, store or handle hydrocarbons. Although we attempt 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 our successful re-entry into the midstream business, including our ability to compete for individual projects.

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

Our operations are subject to a number of inherent risks including fires, earthquakes, adverse weather conditions (such as extreme cold or heat, hurricanes, tornadoes, lightning and flooding) and other natural disasters; terrorist activity or acts of aggression; the collision of equipment of third parties on our infrastructure (such as damage caused to our underground pipelines by third party excavation or construction); 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 infrastructure is repaired or replaced, each of which could cause us to suffer substantial losses. Our offshore operations may encounter additional marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, and governmental regulations (including interruption or termination of drilling rights by governmental authorities based on environmental, safety and other considerations). In addition, although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns as a result of global emissions of greenhouse

**Table of Contents**

gas (GHG) could 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.

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, we do not carry or are unable to obtain insurance coverage on terms that we find acceptable for certain exposures including, but not limited to certain environmental exposures (including potential environmental fines and penalties), business interruption, named windstorm / hurricane exposures and, in limited circumstances, certain political risk exposure. 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. 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 operations 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 interest in Citrus Corporation (and its Florida Gas operations) and GLNG 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 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 and (d) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. In addition, we depend on third parties to gather, store and transport natural gas upstream or downstream of the assets or facilities of our businesses. If these third party facilities were to become unavailable or reduced for any reason, then revenues generated from our assets and facilities that utilize them could be negatively impacted.

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

Our operations are subject to a complex set of federal, state and local laws and regulations that tend to change from time to time and generally are becoming increasingly more stringent. In addition to laws and regulations affecting our individual business units, there are various laws and regulations that regulate various market practices in the industry, including antitrust laws and laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission (FTC), FERC and CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years. In addition, all of our businesses are subject to laws and regulations that govern environmental, health and safety matters. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, as well as regulations designed for the protection of human health and safety and threatened or endangered species. Compliance obligations can result in significant costs to install and maintain pollution controls, and to maintain measures to address personal and process safety and protection of the environment and animal habitat near our operations. We are often obligated to obtain permits or approvals in our operations from various federal, state and local authorities, which permits and approvals 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.

**Table of Contents*****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 regulation 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 implement 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.* There have been various legislative and regulatory proposals at the federal and state levels to address climate change and to regulate GHG emissions. The Environmental Protection Agency (EPA) and several state environmental agencies have already adopted regulations to regulate GHG emissions. Although natural gas as a fuel supply for power generation has the least GHG emissions of any fossil fuel, 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, including the level of any emission standards; the amount and costs of allowances, offsets and credits granted; 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 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 at the federal and state levels to address various emissions from coal-fired power plants. Although such proposals will generally favor the use of natural gas fired power plants over coal-fired power plants, 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 proposed more stringent ozone standards, as well as implemented more stringent emission standards with regard to certain combustion engines on our pipeline systems. It is uncertain what impact new environmental regulations might have on us until further definition is provided in the various legislative, regulatory and judicial branches. In addition, any regulations would likely increase our costs of compliance by requiring us to monitor emissions, install additional equipment to reduce carbon emissions and possibly to purchase emission credits, as well as potentially delay the receipt of permits and other regulatory approvals. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance in the rates charged by our pipelines and in the prices at which we sell oil, natural gas and NGLs, our ability to recover such costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final regulations and legislation.

*Renewable / Conservation Legislation.* There have been various legislative and regulatory proposals at the federal and state levels 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.* Partially as a result of a recent explosion on an offshore platform of a third party and subsequent release of oil into the Gulf of Mexico, there have been various regulations proposed and implemented that could materially impact the costs of exploration and production operations, 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.

**Table of Contents**

*Pipeline Safety.* Various legislative and regulatory reforms associated with pipeline safety and integrity issues have been recently proposed, including reforms that would require increased periodic inspections, installation of additional valves and other equipment on our pipelines and subjecting additional pipelines (including gathering and intrastate pipeline facilities) to more stringent regulation. It is uncertain what reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results.

*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 natural gas and oil 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.

*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.

*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.

**Table of Contents*****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.

**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, our Ruby and FGT Phase VIII projects are not currently fully subscribed and there is a risk that we will not be able to obtain additional customer commitments, 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 gas that we transport and store also depends on the availability of natural gas supplies that are attached 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.

***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 Interior, the U.S. Coast Guard, the U.S. Department of Homeland Security and various state and local regulatory agencies whose actions have the potential to adversely affect our profitability. FERC regulates most aspects of our business, including the terms and conditions of services offered, our relationships with affiliates,

**Table of Contents**

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. Three of our pipeline systems have filed or will file rate cases that will establish new rates in 2011. There is a risk that 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 in 2009 and 2010 against unaffiliated pipeline systems to reduce the rates they were charging their customers. There is a risk that the FERC or our customers could file similar complaints on one or more of our pipeline systems and that a successful complaint against our pipelines' rates could have an adverse impact on us.

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 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 decrease over time and thereby negatively impact our ability to renew contracts at rates that were previously in place. 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.

***The expansion of our pipeline systems by constructing new facilities subjects us to construction and other risks that may adversely affect us.***

We frequently expand the capacity of our existing pipeline, storage or LNG facilities by constructing additional facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

Our ability to obtain necessary approvals and permits from the FERC and other regulatory agencies on a timely basis that are on terms that are acceptable to us, including the potential negative impact of delays and increased costs caused by general opposition to energy infrastructure development, especially in environmentally, culturally sensitive and more heavily populated areas;

The ability to access sufficient capital at reasonable rates to fund expansion projects, especially in periods of prolonged economic decline when we may be unable to access the capital markets;

The availability of skilled labor, equipment, and materials to complete expansion projects;

Potential changes in federal, state and local statutes, regulations, and orders;

Impediments on our ability to acquire rights-of-way or land rights on terms that are acceptable to us;  
39

---

**Table of Contents**

Our ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from weather conditions, geologic conditions, inflation or increased costs of equipment, materials (such as steel and nickel), labor, contractor productivity, delays in construction due to various factors including delays in obtaining regulatory approvals or other factors beyond our control. These cost overruns could be material and we may not be able to recover such excess costs from our customers which could negatively impact the return on our investments or could result in financial impairments;

Our ability to construct projects within anticipated time frames that would likely delay our collection of transportation charges under our contracts;

The failure of suppliers and contractors to meet their performance and warranty obligations; and

The lack of transportation, storage or throughput commitments.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. There is also the risk that a downturn in the economy and its negative impact upon natural gas demand may result in either slower development in the potential for future expansion projects or adjustments in the contractual commitments supporting such projects. As a result, new facilities may be delayed or may not achieve our expected investment return.

***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, 2010, 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 24 percent, 59 percent, 48 percent and 45 percent of their respective operating revenues. 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, 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 associated with pipeline safety and integrity issues will be adopted that could require us to incur additional material expenditures in the future.

***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. Our loss of or interference with these rights could have a material adverse effect on us.

**Table of Contents**

***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 GAAP principles for nonregulated entities. For example, FERC accounting policies permit certain regulatory assets to be recorded 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 (AFUDC) 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. Currently, our Ruby Pipeline and FGT Phase VIII projects are not fully subscribed and therefore we may experience a reduction in earnings at the pipeline subsidiary levels when they go into service and may negatively impact our return on investment.

**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, the amount of any impairment is transferred to the full cost pool if a reserve base exists or is expensed if a reserve base has not yet been created. Impairments transferred to the full cost pool increase the depletion rate for that country.

***Our natural gas and oil 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 (a) that we may not encounter commercially productive reservoirs or (b) if we encounter commercially producible reservoirs, that 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 recently acquired acreage positions in two new 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.



**Table of Contents**

***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 locate joint working interest owners to assist in funding and enhancing the value of the development of certain of areas such as our Eagle Ford shale acreage;

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;

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, including environmental approvals for our Pinauna project in Brazil;

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, including our ability to obtain partners in certain of our operating areas, 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,

**Table of Contents**

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 natural gas and oil reserves. Finally, the timing of the production and the expenses related to the development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value.

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 natural gas and oil 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 rates, 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.

**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.

**Table of Contents**

***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, natural gas and oil reserves committed to gathering and processing facilities may not be as large as expected, the life of the reserves may not be as long as expected or the producers may elect not to develop such reserves. We also cannot influence or control the production or the speed of development of the third-party 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, including our Corporate and Legacy Businesses**

***Our foreign operations and investments involve special risks.***

Our activities outside the United States include (a) pipeline 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 project 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, 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, including those required for the Pinauna project;

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 new 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.

**Table of Contents*****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, 2010. While we do not currently expect to make additional cash contributions in 2011, we may be required to make additional pension plan contributions in the future. Additionally, our pension plan is supported by assets held in trust that 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 retirees. Medical costs have been generally increasing and such costs could require us to incur additional liabilities and make additional cash expenditures to fund such programs that could have a negative impact on our financial results. Furthermore, the costs of maintaining such welfare plans could be negatively impacted by changes that might arise out of recent health care legislation, the effects of which have not been fully determined at this point. Any of these events, which are beyond our control, could negatively impact us.

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

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

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

We have extensive capital programs in each of our businesses, which requires us to frequently access the capital markets. Although the markets have become less volatile than they were several years ago, volatility in the financial markets remain. Since we are rated below investment grade at this time, our ability to access the capital markets and

the cost of capital could be negatively impacted in the future. This could require us to forego capital opportunities or make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us with investment grade ratings.

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

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

***If we are unable to renew our revolving credit facility that expires in November 2012, then it would negatively impact us.***

We have a corporate revolving credit facility that is due to expire November of 2012. Prior to maturity, we plan to renew or extend this credit facility. However, many other companies have similar expiration and renewal requirements and we will be competing for available credit capacity of the financial institutions, many of which are in the process of deleveraging their balance sheets. It remains uncertain what credit capacity we will be able to obtain upon renewal. In addition, it is likely that the cost of such credit facilities (spreads over LIBOR) will increase above current levels. The amount of credit capacity we are able to obtain and the ultimate cost of such credit could have a negative impact on our liquidity, cost of capital and financial results. In addition, to the extent that we decrease the amount of capacity under our corporate revolver when it is renewed, there is a risk that such liquidity levels may not be adequate in the future especially if commodity prices remain at or decline from current levels and our access to capital markets is restricted in the future. In that case, such liquidity levels may not be adequate to manage our business and we could be significantly adversely affected. Finally, the financial covenants set forth in any new facility may be more restrictive than our current facility and reduce our financial and operating flexibility.

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

We maintain \$1.3 billion of our liquidity through the borrowing base facilities of our exploration and production subsidiary. A downward revision of our proved reserves, due to future declines in commodity prices, performance revisions or otherwise, could require a redetermination of the borrowing base and could negatively impact our ability to source funds from such facilities. In addition, currently our proved reserves serve as collateral for many of the derivative contracts that we enter into to hedge the commodity price for our production. A reduction in our proved reserves could require us to post additional collateral in the future for a portion of those derivative contracts.

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

Certain of our debt and other financing obligations contain restrictive covenants, including debt to earnings before interest, income taxes, depreciation and amortization (EBITDA) and fixed charges to EBITDA covenants in our revolving credit agreement, and contain cross default provisions. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we might not be able to repay such debt and other financing obligations. Additionally, some of our credit agreements are collateralized by our equity interests in EPNG and TGP as well as certain natural gas and oil reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to foreclose on these collateral interests.

**Table of Contents*****We are subject to interest rate risks.***

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

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

GIP has invested approximately \$700 million to acquire a 50 percent indirect interest in our Ruby pipeline project. Subject to certain extensions, to the extent that we are unable to complete the construction of the Ruby pipeline by near the end of 2011, then GIP has an option to require us to repurchase its equity interests. These repayment obligations are secured by various interests in Ruby Pipeline Holding Company, L.L.C. (Ruby), Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains) and certain of our common units held in EPB. Adverse economic conditions, as well as restrictions on our ability to access the capital markets could negatively impact our ability to meet such obligations, as well as permit GIP to foreclose on such security interests. In addition, GIP can elect to maintain its equity interest in Cheyenne Plains if we fail to complete the Ruby pipeline by near the end of 2011. We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us.

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

We hold debt at a holding company level, a company with no significant assets other than our ownership interests in our operating subsidiaries. We are dependent on the earnings and cash flows, dividends, loans or other distributions from our subsidiaries and joint ventures to generate the funds necessary to meet these obligations. Applicable law and contractual restrictions (including restrictions in our subsidiaries' credit facilities and in our joint venture or partnership agreements) may negatively impact our ability to obtain such distributions from our subsidiaries, including the rights of the creditors of our subsidiaries that would often be superior to our interests. A substantial portion of our investments in our interstate pipeline assets are held through subsidiaries or joint ventures. In this regard, our partnership interest in EPB and our 50% ownership interest in Citrus (the holding company for Florida Gas) generally generate substantial cash flow to us. Therefore, our cash flow is dependent upon the ability of EPB to make distributions to its partners (including the incentive distribution rights to us as the general partner) and the level of distributions by Citrus to us, net of any cash calls. A significant decline in EPB's or Citrus' earnings and/or cash distributions would have a corresponding negative impact on us. For information on the risk factors inherent in the business of EPB, see Item 1A. Risk Factors in the EPB Annual Report and subsequent filings thereof.

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

An important source of capital to us in the past and potentially in the future is the sale of interests in our interstate pipelines and LNG facilities to our master limited partnership, EPB. As the general partner of EPB, we are entitled to incentive distribution rights (IDRs). We are currently entitled to receive the maximum level of IDRs. Our ability to sell additional interests to EPB on an accretive basis to the limited partner unitholders may be negatively impacted by such IDRs unless we elect to reduce the level of the IDRs as provided for in the partnership agreement. In addition, as the general partner of the partnership, we could also be subject to claims associated with conflicts of interest and breach of fiduciary duties. Although the partnership agreements expressly define and limit our obligations as the general partner, if any conflicts of interest or breach of fiduciary duties are found, then our ability to sell additional interests in our interstate pipeline assets to EPB could be negatively impacted and any liability resulting from such claims could be material. In either event, there is a risk that this source of capital to us may not

**Table of Contents**

be available to us or may become more restricted, thereby negatively impacting the deleveraging of our balance sheet and/or our future capital programs. The ability to sell additional interests in our interstate pipelines and LNG facilities to EPB is also subject to the ability of EPB to access the capital markets. If the access to such markets is unavailable or restricted or if the cost of capital increases, then this important source of capital to us could be negatively impacted in the future. Finally, our ability to sell interests in other pipeline subsidiaries may be restricted by covenants under existing debt agreements.

*We may not be able to execute our long range plan and growth strategy as planned.*

Our ability to execute our long range plan and our growth strategy is dependent on many factors outside of our control. As a result, our projected revenues, earnings, cash flows and the reductions in our debt levels over the plan cycle may be less than our plan has anticipated. The actual results derived from our businesses could deviate materially from planned outcomes. Our long range plan could also be impacted by material acquisitions, divestitures or restructurings of our businesses that we believe would be beneficial to our investors.

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 2. PROPERTIES**

A description of our properties is included in Part I, Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

**ITEM 3. LEGAL PROCEEDINGS**

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

EPA Compliance Order – Bluebell Gas Plant. In February 2008, we received a Compliance Order from Region 8 of the EPA alleging violations of Clean Air Act regulations at the Bluebell Gas Plant and other facilities. The allegations concerned the compliance of those facilities with hazardous air pollutant regulations under the Clean Air Act. The Compliance Order did not specify what, if any, penalty may result. After meeting with the EPA in June 2008 and conducting testing requested by the EPA, we determined that only the Bluebell Gas Plant was subject to the regulations. Following that determination, we worked with the EPA and the Utah Department of Environmental Quality so that the Bluebell Gas Plant complied with these regulations. In the first quarter of 2010, the Bluebell Gas Plant was shut down, and we have informed the EPA and the Utah Department of Environmental Quality of this information. We have requested that the EPA close this Compliance Order and are awaiting response from the EPA.

**ITEM 4. (REMOVED AND RESERVED)**

**Table of Contents****PART II****ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.**

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of February 22, 2011, we had 26,387 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

*Quarterly Stock Prices.* The following table reflects the quarterly high and low sales prices for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange and the cash dividends per share we declared in each quarter:

|                | <b>High</b> | <b>Low</b> | <b>Dividends</b> |
|----------------|-------------|------------|------------------|
| <b>2010</b>    |             |            |                  |
| Fourth Quarter | \$14.08     | \$12.00    | \$0.01           |
| Third Quarter  | 12.93       | 10.60      | 0.01             |
| Second Quarter | 13.00       | 10.17      | 0.01             |
| First Quarter  | 11.59       | 9.55       | 0.01             |
| <b>2009</b>    |             |            |                  |
| Fourth Quarter | \$11.37     | \$ 8.94    | \$0.01           |
| Third Quarter  | 10.85       | 8.00       | 0.05             |
| Second Quarter | 10.91       | 6.10       | 0.05             |
| First Quarter  | 9.52        | 5.22       | 0.05             |

*Stock Performance Graph.* This graph reflects the comparative changes in the value of \$100 invested since December 31, 2005 as invested in (i) El Paso's common stock, (ii) the Standard & Poor's 500 Stock Index, (iii) the Standard & Poor's 500 Oil & Gas Storage & Transportation Index and (iv) our Peer Group identified below. The Peer Group we used for this comparison is the same group we use to compare total shareholder return relative to our performance for compensation purposes. Our peer group for 2010 included the following companies: Anadarko Petroleum Corp., CenterPoint Energy Inc., Dominion Resources, Inc., Enbridge, Inc., Energen Corp., EQT Corp., National Fuel Gas Co., Newfield Exploration Co., NiSource, Inc., Noble Corp., ONEOK, Inc., Pioneer Natural Resources Co., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., TransCanada Corp., and Williams Companies, Inc. Our peer group for 2009 included Apache Corp., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., XTO Energy Inc., and the companies listed above excluding Energen Corp.

**Table of Contents****COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS**

|   | <b>12/05</b> | <b>12/06</b> | <b>12/07</b> | <b>12/08</b> | <b>12/09</b> | <b>12/10</b> |
|---|--------------|--------------|--------------|--------------|--------------|--------------|
| <b>El Paso Corporation</b>  | \$100        | \$127.09     | \$144.81     | \$66.73      | \$ 85.49     | \$120.03     |
| <b>S&amp;P 500 Stock Index</b>                                      | \$100        | \$115.79     | \$122.16     | \$76.96      | \$ 97.33     | \$112.03     |
| <b>S&amp;P 500 Oil &amp; Gas Storage &amp; Transportation Index</b> | \$100        | \$118.95     | \$135.88     | \$67.53      | \$ 94.37     | \$120.23     |
| <b>2010 Peer Group</b>  | \$100        | \$117.51     | \$142.83     | \$86.59      | \$138.34     | \$171.03     |
| <b>2009 Peer Group</b>  | \$100        | \$107.56     | \$138.49     | \$90.74      | \$140.64     | \$168.21     |

Note: The annual values of each investment are based on the share price appreciation and assume cash dividend reinvestment. The calculations exclude any applicable brokerage commissions and taxes. Cumulative total stockholder returns from each investment can be calculated from the annual values given above.

*Dividends Declared.* On February 8, 2011, we declared a quarterly dividend of \$0.01 per share of our common stock, payable on April 1, 2011, to shareholders of record as of March 4, 2011. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

**Table of Contents**

*Other.* The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set apart for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restrictions on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If we are unable to comply with our fixed charge ratio, our ability to pay additional dividends would be restricted.

*Odd-lot Sales Program.* We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. This voluntary program offers these stockholders a convenient method to sell all of their odd-lot shares at one time without incurring any brokerage costs. We also have a dividend reinvestment and common stock purchase plan available to all of our common stockholders of record. This voluntary plan provides our stockholders a convenient and economical means of increasing their holdings in our common stock. Neither the odd-lot program nor the dividend reinvestment and common stock purchase plan have a termination date; however, we may suspend either at any time. You should direct your inquiries to Computershare Trust Company, N.A., our stock transfer agent at 1-877-453-1503.







Managed commodity price risk through derivative contracts on 2010, 2011 and 2012 natural gas production

Increased oil and liquids based revenues in 2010 to 23 percent of our total revenues, an 8 percent increase from 2009









- (2) Amounts represent our proportional share of the estimated costs for these unconsolidated affiliates. Our estimated equity contribution is included in our expected 2011 capital plan.
- (3) Amount includes 100 percent of our Ruby pipeline project expenditures. As of December 31, 2010, we have received approximately \$0.7 billion in funding from our equity partner on this project.
- (4) The South System III expansion project consists of three phases. In January 2011, Phase I of the project was placed in service. Phases II and III are expected to be placed in service in June 2011 and June 2012, respectively. Phase II of the Southeast Supply Header project is expected to be placed in service in June 2011.
- (5) Amount includes approximately \$295 million that we paid to acquire a 50 percent interest in this project.











operations as a result of the shift in flow patterns primarily on our TGP system, partially offset by \$15 million of lower electric compression usage. Higher realized prices on operational sales and lower imbalance revaluations contributed favorably to our EBIT by approximately \$16 million in 2009 compared to 2008. In addition, lower electric compression usage increased our EBIT by \$13 million for the year ended December 31, 2009 when compared to 2008. Our future earnings may be impacted positively or negatively depending on changes in throughput, as well as fluctuations in natural gas prices. We continue to explore options to minimize the price volatility associated with these operational pipeline activities. As a result of the TGP rate case filed with the FERC which proposes an increase in base tariff rates effective June 1, 2011, the percentage of our revenues derived from reservation charges may increase and therefore may reduce the impacts to our EBIT due to excess fuel recoveries.







































2008, we also recognized (i) mark to market losses on production-related natural gas and crude contracts that we held and managed during that year and (ii) \$19 million of revenue related to bankruptcy settlements associated with natural gas derivative contracts.







agreement with GIP, see Item 8, Financial Statements and Supplementary Data, Notes 11 and 17.

**Table of Contents**

We expect our current liquidity sources and operating cash flow to be sufficient to fund our estimated 2011 capital program. In 2011 we also have debt maturities of approximately \$500 million which we will pay off as they mature. Additionally, before the end of 2012 we will be required to renew our primary long-term revolving credit facilities (See Item 8, Financial Statements and Supplementary Data, Note 11). The most significant of these facilities are our \$1.5 billion EPC revolver and \$1.3 billion EPEP revolving credit facilities. As of and for the year ended December 31, 2010, the amount borrowed or utilized for letters of credit under these two facilities aggregated to approximately \$0.9 billion. As a result of our 2010 actions, our current available liquidity, hedging program in place on our natural gas and oil production, and planned future actions (including continuing with our MLP drop down strategy as markets permit), we believe we are well positioned to meet our obligations as well as continue with our efforts to strengthen our balance sheet. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements as well as address further changes in the financial and commodity markets. However, there are a number of factors that could impact our plans, including our ability to access the financial markets to fund our long-term capital needs if the financial markets are restricted, or a further decline in commodity prices. If these events occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets, all of which could impact our financial and operating performance.









obligations. Included are the following:

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







with a specified dollar amount, we have a maximum stated value of approximately \$0.8 billion. As of December 31, 2010, we have recorded obligations of \$18 million related to our guarantee and indemnification



(1) If the actual return on plan assets was one percent lower than the expected return on plan assets, our expected cash contributions to our pension and other postretirement benefit plans would not change significantly.

The estimates for our net benefit expense or income are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred over three years, after which they are considered for inclusion in net benefit expense or income. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit expense would have been \$15 million higher for the year ended December 31, 2010.

*Price Risk Management Activities.* We record the derivative instruments used in our price risk management activities at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary assumptions used to estimate the fair value of



|                                   | <b>Fair<br/>Value</b> | <b>Change in Credit Risk</b>                 |                                     | <b>Fair<br/>Value</b> | <b>Change</b> |
|-----------------------------------|-----------------------|--|-------------------------------------|-----------------------|---------------|
|                                   |                       | <b>1 Percent Increase<br/>Fair<br/>Value</b> | <b>Change<br/>(In<br/>millions)</b> |                       |               |
| Production-related derivatives    | \$ 237                | \$ 235                                       | \$ (2)                              | \$ 239                | \$ 2          |
| Other commodity-based derivatives | (423)                 | (419)  | 4                                   | (429)                 | (6)           |
| Total                             | \$ (186)              | \$ (184)                                     | \$ 2                                | \$ (190)              | \$ (4)        |



*Principles of Consolidation.* For entities where both we and third parties have equity or other interests, we perform an evaluation to determine which party should consolidate the entity. As part of this evaluation, we are required to determine whether or not the entity is considered a variable interest entity (VIE) and ultimately which party is considered the primary beneficiary and/or who controls the entity's operating and financial decisions. As part of these evaluations, there is a significant amount of judgment involved in evaluating the entities' contractual relationships, the relative nature of the third party's and our interests in the entities, and the ability to control or direct its activities. If different judgment were applied, our accounting treatment and financial statement presentation for these entities could be significantly impacted. For a further discussion of our significant variable interest entities and investments in unconsolidated affiliates as of December 31, 2010, see Item 8. Financial Statements and Supplementary Data, Notes 17 and 18.





Edgar Filing: EL PASO CORP/DE - Form 10-K

|  |       |       |       |       |       |        |          |          |          |          |
|--|-------|-------|-------|-------|-------|--------|----------|----------|----------|----------|
| Variable rate long-term<br>debt and other obligations <sup>(1)</sup> | \$ 30 | \$888 | \$ 76 | \$ 82 | \$185 | \$ 859 | \$ 2,120 | \$ 2,103 | \$ 2,163 | \$ 1,981 |
| Average interest rate  | 3.9%  | 2.1%  | 3.0%  | 3.0%  | 4.3%  | 2.3%   |          |          |          |          |

(1) Includes current portion.













































Edgar Filing: EL PASO CORP/DE - Form 10-K

|        |       |          |          |
|--------|-------|----------|----------|
| U.S.   | \$    | \$ 2,031 | \$ 2,181 |
| Brazil |       | 58       | 479      |
| Egypt  | 25    | 34       | 9        |
| Total  | \$ 25 | \$ 2,123 | \$ 2,669 |

109

---















the term of these swaps. For a further discussion of our Ruby financing, see Note 11.

We also have long-term debt with fixed interest rates that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps designated as fair value hedges to protect the value of certain of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments. We record changes in the fair value of these derivatives in interest expense which is offset by changes in the fair value of the related hedged items. As of December 31, 2010 and 2009, these interest rate swaps converted the interest rate on approximately \$184 million and \$218 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%.













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

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

As of December 31, 2010, we have approximately 48 counterparties to our derivative contracts. Based on our assessment of counterparty risk in light of the collateral our counterparties have posted with us, we have determined that our exposure is primarily related to our production-related derivatives and is limited to ten financial institutions, each of which has a current Standard & Poor's credit rating of A or better. Additionally, as of December 31, 2010, three counterparties, Morgan Stanley Capital Group, RRI Energy Services, and Citibank comprise 26 percent, 23 percent and 20 percent, respectively, of our net financial instrument exposure. As of December 31, 2009, three counterparties, Williams Gas Marketing, Citibank, and RRI Energy Services, comprised 31 percent, 13 percent and 11 percent, respectively, of our net financial instrument asset exposure. The concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.







**Table of Contents****9. Other Assets and Liabilities**

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

|                            | <b>2010</b>          | <b>2009</b>   |
|----------------------------|----------------------|---------------|
|                            | <b>(In millions)</b> |               |
| Other current assets       |                      |               |
| Prepaid expenses           | \$ 54                | \$ 71         |
| Regulatory assets (Note 8) | 36                   | 25            |
| Other                      | 16                   | 30            |
| <b>Total</b>               | <b>\$ 106</b>        | <b>\$ 126</b> |

|   |               |               |
|---|---------------|---------------|
| Other non-current assets                            |               |               |
| Regulatory assets (Note 8)                          | \$ 349        | \$ 270        |
| Unamortized debt expenses                           | 161           | 123           |
| Pension and other postretirement benefits (Note 13) | 106           | 88            |
| Notes receivable from affiliates                    | 101           | 78            |
| Long-term receivables                               | 89            | 90            |
| Other   | 106           | 112           |
| <b>Total</b>  | <b>\$ 912</b> | <b>\$ 761</b> |

|   | <b>2010</b>          | <b>2009</b>   |
|---|----------------------|---------------|
|   | <b>(In millions)</b> |               |
| Other current liabilities                           |                      |               |
| Accrued taxes, other than income                    | \$ 144               | \$ 114        |
| Environmental, legal and rate reserves (Note 12)    | 106                  | 193           |
| Regulatory liabilities (Note 8)                     | 96                   | 62            |
| Pension and other postretirement benefits (Note 13) | 44                   | 44            |
| Income taxes  | 30                   | 19            |
| Deposits  | 37                   | 32            |
| Dividends payable                                   | 16                   | 16            |
| Other   | 157                  | 204           |
| <b>Total</b>  | <b>\$ 630</b>        | <b>\$ 684</b> |

|   |                 |                 |
|---|-----------------|-----------------|
| Other non-current liabilities                       |                 |                 |
| Pension and other postretirement benefits (Note 13) | \$ 626          | \$ 597          |
| Regulatory liabilities (Note 8)                     | 177             | 236             |
| Environmental and legal reserves (Note 12)          | 133             | 138             |
| Asset retirement obligations (Note 10)              | 125             | 133             |
| Insurance reserves                                  | 68              | 75              |
| Other   | 332             | 312             |
| <b>Total</b>  | <b>\$ 1,461</b> | <b>\$ 1,491</b> |



**Table of Contents****10. Property, Plant and Equipment**

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

|                                     | <b>Method</b> | <b>Depreciable<br/>Lives<br/>(In years)</b> |
|-------------------------------------|---------------|---|
| Regulated transmission systems      | Composite     | (1)   |
| Non-regulated assets                |               |   |
| Natural gas and oil properties      | (2)           | (2)   |
| Transmission and storage facilities | Straight-line | 15-40                                       |
| Gathering and processing systems    | Straight-line | 10-22                                       |
| Transportation equipment            | Straight-line | 5-15  |
| Buildings and improvements          | Straight-line | 7-50  |
| Office and miscellaneous equipment  | Straight-line | 3-15  |

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

(2) Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated.

*Excess purchase costs.* As of December 31, 2010 and 2009, TGP and EPNG have excess purchase costs associated with their historical acquisition. Total excess costs on these pipelines were approximately \$2.5 billion and accumulated depreciation was approximately \$0.5 billion at December 31, 2010 and 2009. These excess costs are being depreciated over the estimated life of the pipeline assets to which the costs were assigned, and our related depreciation expense for each year ended December 31, 2010, 2009, and 2008 was approximately \$42 million.

*Capitalized costs during construction.* We capitalize a carrying cost on funds related to the construction of long-lived assets and reflect these amounts as increases in the cost of the asset on our balance sheet. We capitalize an allowance for funds used during construction (AFUDC), that consists of (i) an interest cost on our debt that could be attributed to the assets being constructed, and (ii) for our regulated pipelines, a return on our equity that could be attributed to the assets being constructed. The equity portion is calculated using the most recent FERC approved equity rate of return. Interest costs capitalized are included as a reduction of interest expense in our income statements and were \$60 million, \$48 million and \$45 million during the years ended December 31, 2010, 2009 and 2008. Equity amounts capitalized (exclusive of taxes) in our FERC regulated business are included as other non-operating income on our income statement and were \$156 million, \$61 million and \$37 million during the years ended December 31, 2010, 2009 and 2008. These amounts are recovered over the depreciable lives of the long-lived assets to which they relate and are non-cash investing activities.

*Construction work-in progress.* At December 31, 2010 and 2009, we had approximately \$4.8 billion and \$3.6 billion of construction work-in-progress included in our property, plant and equipment.

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



**Table of Contents**

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

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

|  | 2010          | 2009   |
|--|---------------|--------|
|  | (In millions) |        |
| Net asset retirement obligation at January 1   | \$ 291        | \$ 254 |
| Liabilities settled                            | (84)          | (72)   |
| Accretion expense                              | 20            | 21     |
| Liabilities incurred                           | 11            | 16     |
| Changes in estimate <sup>(1)</sup>             | (51)          | 72     |
| Net asset retirement obligation at December 31 | \$ 187        | \$ 291 |

<sup>(1)</sup> Reflects updated information received on our hurricane related asset retirement obligations.

Table of Contents**11. Debt, Other Financing Obligations and Other Credit Facilities**

|  | <b>Year Ended December 31,</b> |             |
|--|--------------------------------|-------------|
|  | <b>2010</b>                    | <b>2009</b> |
|  | <b>(In millions)</b>           |             |
| Short-term financing obligations, including current maturities | \$ 489                         | \$ 477      |
| Long-term financing obligations                                | 13,517                         | 13,391      |
| Total  | \$ 14,006                      | \$ 13,868   |

The following provides additional detail on our financing obligations:

|  | <b>Year Ended December 31,</b> |               |
|--|--------------------------------|---------------|
|  | <b>2010</b>                    | <b>2009</b>   |
|  | <b>(In millions)</b>           |               |
| <b>CIG</b>   |                                |               |
| Notes and debentures, 5.95% through 6.85%, due 2015 through 2037 | \$ 475                         | \$ 475        |
| El Paso Corporation  |                                |               |
| Notes, 6.50% through 12.00%, due 2011 through 2037               | 5,469                          | 6,362         |
| \$1.5 billion revolver, variable due 2012                        | 225                            | 425           |
| <b>EPNG</b>  |                                |               |
| Notes, 5.95% through 8.625%, due 2017 through 2032               | 1,115                          | 1,169         |
| El Paso Exploration & Production Company (EPEP)                  |                                |               |
| Senior note, 7.75%, due 2013                                     | 1                              | 1             |
| Revolving credit facility, variable due 2012                     | 300                            | 834           |
| El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC)      |                                |               |
| Revolving credit facility, variable due 2012                     | 270                            | 520           |
| Notes, 4.10% through 8.00%, due 2011 through 2040                | 1,425                          | 140           |
| Notes, variable due 2012   | 35                             | 35            |
| <b>SNG</b>   |                                |               |
| Notes, 5.90% through 8.00%, due 2017 through 2032                | 911                            | 911           |
| <b>TGP</b>   |                                |               |
| Notes, 6.00% through 8.375%, due 2011 through 2037               | 1,876                          | 1,876         |
| Other  | 222                            | 237           |
|  | <b>12,324</b>                  | <b>12,985</b> |
| <b>Other financing obligations</b>                               |                                |               |
| Capital Trust I, due 2028  | 325                            | 325           |
| Ruby Pipeline Holding Company <sup>(1)</sup>                     |                                | 217           |
| Ruby Pipeline, L.L.C. credit facility                            | 1,094                          |               |
| Other  | 320                            | 455           |
| Subtotal   | 14,063                         | 13,982        |
| Less:  |                                |               |
| Other, including unamortized discounts and premiums              | 57                             | 114           |
| Current maturities   | 489                            | 477           |

|  |           |           |
|--|-----------|-----------|
| Total long-term financing obligations, less current maturities | \$ 13,517 | \$ 13,391 |
|--|-----------|-----------|

(1) This amount was converted to Ruby convertible preferred equity interest in August 2010. For further information, see Note 17.

**Table of Contents**

*Changes in Financing Obligations.* During 2010, we had the following changes in our long-term financing obligations (in millions):

| <b>Company</b>                                     | <b>Interest Rate</b> | <b>Book Value Increase (Decrease)</b> | <b>Cash Received (Paid)</b> |
|--|----------------------|---------------------------------------|-----------------------------|
| <b>(In millions)</b>                               |                      |                                       |                             |
| <i>Issuances</i>                                   |                      |                                       |                             |
| Ruby Holding Company <sup>(1)</sup>                | 13.00%               | \$ 188                                | \$ 187                      |
| Ruby Pipeline, L.L.C. credit facility              | variable             | 1,094                                 | 1,037                       |
| El Paso notes due 2020 <sup>(2)</sup>              | 6.50%                | 349                                   | (4)                         |
| EPPOC notes due 2015-2040                          | 4.10% - 7.50%        | 1,283                                 | 1,268                       |
| EPEP revolving credit facility                     | variable             | 500                                   | 500                         |
| El Paso revolving credit facility                  | variable             | 193                                   | 193                         |
| EPPOC revolving credit facility                    | variable             | 160                                   | 160                         |
| Other  | variable             | 19                                    | 19                          |
| <i>Increases through December 31, 2010</i>         |                      | <b>\$ 3,786</b>                       | <b>\$ 3,360</b>             |
| <i>Repayments, repurchases, and other</i>          |                      |                                       |                             |
| EPEP revolving credit facility                     | variable             | \$ (1,034)                            | \$ (1,034)                  |
| El Paso revolving credit facility                  | variable             | (393)                                 | (393)                       |
| EPPOC revolving credit facility                    | variable             | (410)                                 | (410)                       |
| El Paso notes due 2010                             | 7.75% - 10.75%       | (182)                                 | (182)                       |
| El Paso notes due 2013 <sup>(2)</sup>              | 12.00%               | (324)                                 | (77)                        |
| El Paso notes due 2011 through 2016 <sup>(2)</sup> | 7.00% - 12.00%       | (693)                                 | (800)                       |
| Elba Express Company L.L.C. credit facility        | variable             | (157)                                 | (157)                       |
| Ruby Holding Company <sup>(1)</sup>                | 13.00%               | (405)                                 |                             |
| Other  | various              | (50)                                  | (74)                        |
| <i>Decreases through December 31, 2010</i>         |                      | <b>\$ (3,648)</b>                     | <b>\$ (3,127)</b>           |

(1) Initial interest rate of 7.00% increased to 13.00% effective April 1, 2010. This amount was converted to Ruby convertible preferred equity interest in August 2010.

(2) See *Loss on Debt Extinguishment* below.

*Loss on Debt Extinguishment.* In 2010, we exchanged approximately \$349 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020. In conjunction with the transaction, we paid \$77 million of cash premiums, and recorded a loss on debt extinguishment of \$105 million.

In December 2010, we repurchased approximately \$709 million of our Senior Notes. In conjunction with the transaction, we paid \$91 million of cash premiums, and recorded a loss on debt extinguishment of \$112 million.

*Debt Maturities.* Aggregate maturities of the principal amounts of long-term financing obligations as of December 31, 2010 for the next 5 years and in total thereafter are as follows (in millions):

|      |        |
|------|--------|
| 2011 | \$ 489 |
| 2012 | 1,281  |
| 2013 | 280    |

|   |           |
|---|-----------|
| 2014  | 534       |
| 2015  | 941       |
| Thereafter  | 10,538    |
| Total long-term financing obligations, including current maturities | \$ 14,063 |

**Table of Contents***Credit Facilities/Letters of Credit*

We have various credit facilities in place which allow us to borrow funds or issue letters of credit or surety bonds. We enter into letters of credit and issue surety bonds in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of December 31, 2010, we had total debt outstanding of \$0.8 billion and approximately \$1.1 billion outstanding in letters of credit and surety bonds issued under all of these facilities including approximately \$0.5 billion related to our price risk management activities. Listed below is a further description of our credit facilities including remaining capacity under the facilities as of December 31, 2010:

| <b>Credit Facility/<br/>Agreement</b>                          | <b>Maturity<br/>Date</b>        | <b>Interest<br/>Rate</b>                          | <b>Commitment/<br/>Facility Fees</b>   | <b>Remaining Capacity<br/>December 31, 2010</b> |
|--|---------------------------------|---|--|---|
| \$1.5 Billion<br>Revolver                                      | November 2012                   | LIBOR + 1.25%<br>1.375% for<br>LCs <sup>(1)</sup> | 0.25% commitment fee<br>on unused capacity <sup>(1)</sup>                    | \$0.9 billion                                   |
| \$500 Million<br>Unsecured Facility                            | July 2011                       | LIBOR or base<br>rate                             | 2.34% fixed facility fee   | \$0.3 billion                                   |
| \$450 Million<br>Unsecured Facility                            | December 2013<br>September 2014 | N/A   | 6.25% (weighted average)<br>facility fee                                     | \$0.03 billion                                  |
| EPEP \$1.0 Billion<br>Revolver                                 | September 2012                  | LIBOR + 1.00%<br>(2)                              | 0.25% unused capacity fee <sup>(2)</sup>                                     | \$0.7 billion                                   |
| EPEP \$300 Million<br>Revolver                                 | December 2011                   | LIBOR + 2.75%                                     | 0.50% facility fee   | \$0.3 billion                                   |
| EPPOC \$750<br>Million<br>Unsecured<br>Revolver <sup>(3)</sup> | November 2012                   | LIBOR +<br>0.575% <sup>(4)</sup>                  | 0.125% commitment fee <sup>(4)</sup><br>0.05% utilization fee <sup>(4)</sup> | \$0.4 billion                                   |

- (1) Based on our December 31, 2010 credit rating. The applicable margin used to calculate interest on borrowings, letters of credit and commitment fees is determined by a variable pricing grid tied to the credit ratings of our senior secured debt.
- (2) Based on December 31, 2010 borrowing levels.
- (3) This facility is only available to EPB and its subsidiaries and borrowings are guaranteed by EPB and its subsidiaries. Amounts borrowed are non-recourse to El Paso. Borrowing capacity is expandable to \$1.25 billion for certain expansion projects and acquisitions.
- (4) Interest rate based on EPB's December 31, 2010 credit rating. The credit facility has two pricing grids, one based on credit ratings and the other based on leverage.

*Restrictive Covenants and Collateral Provisions*

*\$1.5 Billion Revolving Credit Agreement.* El Paso and certain of its subsidiaries have guaranteed this facility, which is collateralized by our stock ownership in EPNG and TGP who are also eligible borrowers. Our covenants under the \$1.5 billion revolving credit facility include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, dividend restrictions, cross default and

cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our credit agreement the most restrictive debt covenants and cross default provisions are:

- (a) Our ratio of Debt to Consolidated earnings before interest, income taxes, depreciation and amortization (EBITDA), each as defined in the credit agreement, shall not exceed 5.25 to 1 until maturity;
- (b) Our ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense plus dividends paid shall not be less than 2.0 to 1 until maturity;
- (c) EPNG and TGP cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the credit agreement, for that particular company to exceed 5.0 to 1; and
- (d) The occurrence of an event of default after the expiration of any applicable grace period, with respect to debt in an aggregate principal amount of \$200 million or more.

**Table of Contents**

*EPEP \$1.0 Billion and \$300 Million Revolving Credit Agreements.* These facilities are collateralized by certain of our natural gas and oil properties. Our \$1.0 billion credit agreement is subject to revaluation on a semi-annual basis. In November 2010, our existing borrowing base was approved by the banks and as of December 31, 2010, the most recent determination was sufficient to fully support this facility. EPEP's borrowings under these facilities are also subject to other conditions. The financial coverage ratio under both facilities requires that EPEP's EBITDA, as defined in the facility, to interest expense not be less than 2.0 to 1 and EPEP's debt to EBITDA, each as defined in the credit agreement, must not exceed 4.0 to 1.

*EPPOC \$750 Million Revolving Credit Facility.* This facility requires that EPB maintain a consolidated leverage ratio, (consolidated indebtedness to consolidated EBITDA (as defined in the credit facility)), of less than 5.0 to 1.0 for any four consecutive quarter periods; and 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified acquisitions. Borrowings under this facility are restricted for use by EPB and its subsidiaries.

*Other Restrictions and Provisions.* In addition to the above restrictions and provisions, we and/or our subsidiaries are subject to various financial and non-financial covenants and restrictions. These covenants and restrictions include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the incurrence of liens; limitations on some of our subsidiaries to participate in our cash management program and potential limitations on the ability of some of our subsidiaries to declare and pay dividends. As of December 31, 2010, the restricted net assets of our consolidated subsidiaries were approximately \$0.9 billion and are primarily related to restrictions on our ability to receive distributions from Ruby until the project is placed in service. Our most restrictive cross-acceleration provision is associated with the indenture of one of our subsidiaries. This indenture states that should an event of default occur resulting in the acceleration of other debt obligations of that subsidiary in excess of \$10 million, the long-term debt obligation containing that provision could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

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

*Other Financing Arrangements*

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

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

*WYCO Development L.L.C. (WYCO).* In conjunction with the construction of the Totem Gas Storage facility and the High Plains pipeline, our joint venture partner in WYCO, funded 50 percent of the construction costs. We reflected these payments made by our joint venture partner as other non-current liabilities on our balance sheet during construction until project completion when these advances were converted into a financing obligation to WYCO. As of December 31, 2010, the principal amounts of the Totem Gas Storage facility and the High Plains pipeline facility were \$75 million and \$104 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. Interest payments on these obligations are based on 50 percent of the operating results of the facilities and are currently estimated at a 15.5 percent rate as of December 31, 2010.

**Table of Contents**

*Ruby Pipeline Financing.* In May 2010, we entered into a seven-year amortizing \$1.5 billion credit facility for our Ruby pipeline project that requires principal payments at various dates through June 2017. During 2010, we borrowed approximately \$1.1 billion under this credit facility, and in 2011 utilized substantially all of the remaining capacity under this facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance \$700 million of the facility by the end of year four. If we do not refinance \$700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that begin in July 2011 and convert the floating LIBOR interest rate to fixed interest rates on approximately \$1.1 billion of total borrowings under this agreement. For a further discussion of these swaps, see Note 7.

We have provided a contingent completion and cost-overflow guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, we are required to post letters of credit for any forecasted cost overruns on the project approved by the lender's independent engineer. As of December 31, 2010, we have posted \$304 million in letters of credit to cover the anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender's engineer in subsequent months, then additional letters of credit will be required to be issued pursuant to the Ruby financing agreements.

**Table of Contents****12. Commitments and Contingencies***Legal Proceedings*

*Cash Balance Plan Lawsuit.* In December 2004, a purported class action lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit alleges various violations of the Employee Retirement Income Security Act and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. In 2010, a trial court dismissed all of the claims in this matter. The dismissal of the case has been appealed.

*Retiree Medical Benefits Matters.* In 2002, a lawsuit entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation* was filed in a federal court in Detroit, Michigan. The lawsuit was filed on behalf of a group of retirees of Case Corporation (Case) that alleged they are entitled to retiree medical benefits under a medical benefits plan for which we serve as plan administrator pursuant to a merger agreement with Tenneco Inc. Although we had asserted that our obligations under the plan were subject to a cap pursuant to an agreement with the union for Case employees, the trial court ruled that the benefits were vested and not subject to the cap. As a result, we are currently obligated to pay the amounts above the cap. In addition, we are obligated to pay damages incurred by retirees prior to the court's ruling that the benefits were not subject to the cap. In 2008, we recorded \$65 million as a reduction to operation and maintenance expense related to the remeasurement of our recorded obligation using actuarial assumptions. We have agreed upon a damage calculation methodology with the plaintiffs and this methodology has been approved by the court. We believe our accruals established for this matter are adequate.

*Price Reporting Litigation.* Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. While some of the cases have been settled or dismissed, several of the cases are in various stages of pre-trial or appellate proceedings. We have seven remaining lawsuits, which consist of (i) six cases that are pending in the United States District Court for the District of Nevada, including *J.P. Morgan Trust Company, NA., Liquidating Trustee v. Oneok, Inc., et al.* (filed August 2005), *Breckenridge, et al. v. El Paso Corporation, et al.* (filed May 2006), *Learjet v. El Paso Corporation, et al.* (filed November 2004), *Arandell Corporation, et al. v. El Paso Corporation, et al.* (filed December 2006), *Heartland Regional, et al. v. El Paso Corporation, et al.* (filed April 2007), and *NewPage Wisconsin System, Inc. v. CMS Energy Resource Management Company, et al.* (filed March 2009); and (ii) one case pending state court in Montana, which is *State of Montana v. Williams Energy Marketing, et al.* (filed July 2003, but not served on El Paso). Although damages in excess of \$140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, our costs and legal exposure related to the remaining outstanding lawsuits and claims are not currently determinable.

*MTBE.* Certain of our subsidiaries used, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies seeking different remedies against us and many other defendants, including remedial activities, damages, attorneys' fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. Eighty-seven of the cases have been settled or dismissed, with all of the settlements being substantially funded by insurance. We have twelve remaining lawsuits, which consist of (i) ten cases that are pending in the MDL including *City of Fresno v. Chevron USA, et al.* (filed October 2003), *New Jersey Dept. of Environmental Protection v. Atlantic Richfield, et al.* (filed June 2007), *City of Pomona v. Chevron, et al.* (filed December 2008), *Village of Roanoke v. Ashland, et al.* (filed April 2009), *Village of Bethalto v. Ashland, et al.* (filed April 2010), *Town of Kouts v. Ashland, et al.* (filed May 2010), *Coraopolis Water & Sewer Authority v. Ashland, et al.* (filed July 2010), *Bridgewater Water Dept. v. Atlantic Richfield, et al.* (filed September 2010), *City of Kennett v. Ashland, et al.* (filed September 2010), and *City of Pattonsburgh v. Ashland, et al.* (filed October 2010); and (ii) two cases that are pending in state courts, including *State of New Hampshire v. Amerada Hess, et al.* (filed October 2003 in a state court in New

Hampshire) and *Mayor & Council of Berlin, et al. v. Ashland, et al.* (filed April 2010 in a state court in Maryland). Of these remaining lawsuits, it is likely that our insurers will assert denial of coverage on

**Table of Contents**

nine of the most-recently filed lawsuits. Although damages in excess of two billion dollars have been alleged in total against all defendants in some of the remaining cases, based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us as well as availability of insurance coverages. Therefore, our costs and legal exposure related to these remaining lawsuits are not currently determinable.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters, including those discussed above, cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2010, we had approximately \$45 million accrued for all of our outstanding legal proceedings.

*Rates and Regulatory Matters*

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

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates as permitted under the settlement of the previous rate case. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

*TGP Rate Case.* In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates, including a proposed change in its rate structure which is expected to increase the percentage of reservation revenues on TGP relative to revenues derived from excess fuel recoveries and throughput on this system. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

*CIG Rate Case.* Under the terms of its 2006 rate case settlement, CIG must file a new general rate case to be effective no later than October 1, 2011. In late January 2011, CIG filed with FERC an amendment of the 2006 settlement, which is unopposed by all of CIG's shippers, to request a modification of the settlement to allow the effective date of the required new rate case to be moved to December 1, 2011. The purpose of the delay in filing date is to allow CIG and its shippers the opportunity to reach a settlement of the rate proceeding before it is formally filed with the FERC. At this time, the outcome of the pre-filing settlement negotiations and the outcome of the upcoming general rate case, in the event pre-filing settlement cannot be reached, is uncertain.

*Environmental Matters*

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at current and former operating sites. At December 31, 2010, we had accrued approximately \$173 million for environmental matters, which has not been reduced by \$19 million for amounts to be paid directly under government sponsored programs or through settlement arrangements with third parties. Our accrual includes



**Table of Contents**

approximately \$170 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately \$3 million for related environmental legal costs.

Our estimates of potential liability range from approximately \$173 million to approximately \$365 million. Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

| <b>Sites</b>  | <b>December 31, 2010</b> |               |
|---------------|--------------------------|---------------|
|               | <b>Expected</b>          | <b>High</b>   |
|               | <b>(In millions)</b>     |               |
| Operating     | \$ 8                     | \$ 11         |
| Non-operating | 151                      | 317           |
| Superfund     | 14                       | 37            |
| <b>Total</b>  | <b>\$ 173</b>            | <b>\$ 365</b> |

*Superfund Matters.* Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as Superfund, or state equivalents for 31 active sites. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

For 2011, we estimate that our total remediation expenditures will be approximately \$48 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately \$24 million in the aggregate for the years 2011 through 2015, including capital expenditures associated with the impact of the Environmental Protection Agency (EPA) rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

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

*Commitments, Purchase Obligations and Other Matters*

*Operating Leases.* We maintain operating leases in the ordinary course of our business activities. These leases include those for office space, operating facilities and equipment. The terms of the agreements vary from 2011 until 2053. Future minimum annual rental commitments under our operating leases net of minimum sublease rentals at December 31, 2010, were as follows:

| <b>Year Ending December 31,</b> | <b>Operating Leases (In millions)</b> |
|---------------------------------|---------------------------------------|
|---------------------------------|---------------------------------------|

|            |    |    |
|------------|----|----|
| 2011       | \$ | 13 |
| 2012       |    | 12 |
| 2013       |    | 11 |
| 2014       |    | 11 |
| 2015       |    | 6  |
| Thereafter |    | 14 |
| Total      | \$ | 67 |

Rental expense was \$39 million for each of the years ended December 31, 2010, 2009, and 2008 and is reflected in operation and maintenance expense. Included in rental expense is approximately \$21 million in each period associated with right-of-way and other arrangements, principally related to a long-term commitment which extends through 2025.

**Table of Contents**

*Guarantees and Indemnifications.* We are involved in various joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim, specificity as to duration, and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately \$0.8 billion, primarily related to indemnification arrangements associated with the sale of ANR Pipeline Company in 2007, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 11. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. We are unable to estimate a maximum exposure of our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of December 31, 2010 and 2009 we recorded obligations of \$18 million and \$52 million related to our guarantee and indemnification arrangements. Our liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its estimated fair value. We have provided a partial parental guarantee of our subsidiary's obligations under this indemnification. We believe that our guarantee and indemnification agreements for which we have not recorded a liability are not probable of resulting in future losses based on our assessment of the nature of the guarantee, the financial condition of the guaranteed party and the period of time that the guarantee has been outstanding, among other considerations.

*Purchase Obligations.* We have construction contracts and contracts to purchase pipe primarily associated with the Ruby Pipeline project and TGP's 300 Line Project which are anticipated to be placed in service during 2011. Under these agreements we estimate approximately \$640 million in obligations for 2011.

*Other Commercial Commitments.* In 2009, the FERC approved an amendment to the 1995 FERC settlement with TGP that provides for interim refunds over a three year period of approximately \$157 million for amounts collected related to certain environmental costs. These refunds are recorded as other current and non-current liabilities on our balance sheet and are expected to be paid over a three year period with interest. As of December 31, 2010, TGP has refunded approximately \$58 million to its customers.

We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2010, we had firm commitments under transportation and storage capacity contracts of \$783 million due at various times and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of approximately \$420 million, the majority of which is due in less than one year.

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

**Table of Contents****13. Retirement Benefits***Overview of Retirement Benefit Plans*

*Pension Plans.* Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat, Inc. or The Coastal Corporation receive the greater of their cash balance benefits or their transition benefits under the prior plan formulas. We do not anticipate making any contributions to our cash balance pension plan in 2011.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We expect to contribute \$4 million to the SERP in 2011.

*Retirement Savings Plan.* We maintain a defined contribution plan covering all of our U.S. employees. We match 75 percent of participant basic contributions up to six percent of eligible compensation and can make additional discretionary matching contributions depending on the overall performance of the Company relative to its peers. Amounts expensed under this plan were approximately \$39 million, \$19 million and \$20 million for the years ended December 31, 2010, 2009 and 2008. For 2010, the amount expensed includes an additional discretionary matching contribution.

*Other Postretirement Benefit Plans.* We provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees (such as to certain retirees of Case as further described in Note 12) and limited postretirement life insurance benefits for current and retired employees. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits. OPEB plans for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. For further information, see Note 8. We expect to contribute \$46 million to our other postretirement benefit plans in 2011.

*Benefit Obligation, Plan Assets and Funded Status.* In accounting for our pension and other postretirement plans, we record an asset or liability based on the over funded or under funded status of each plan. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded either as a regulatory asset or liability for our regulated operations or in accumulated other comprehensive income (loss), a component of stockholders' equity, for all other operations until those gains and losses are recognized in the income statement.

*Other Matters.* In various court rulings prior to March 2008, we were required to indemnify Case Corporation (Case) for certain benefits paid to a closed group of Case retirees as further discussed in Note 12. In conjunction with those rulings, we recorded a liability for estimated amounts due under the indemnification using actuarial methods similar to those used in estimating our postretirement benefit plan obligations. This liability, however, was not included in our postretirement benefit obligations or disclosures prior to 2008.

In the first quarter of 2008, we received a summary judgment from the trial court on this matter, and thus became the primary party that is obligated to pay for these benefit payments. As a result of the judgment, we adjusted our obligation using current actuarial assumptions, recording a \$65 million reduction to operation and maintenance expense.

**Table of Contents**

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

|   | Pension Benefits |          | OPEB     |          |
|---|------------------|----------|----------|----------|
|   | 2010             | 2009     | 2010     | 2009     |
|   | (In millions)    |          |          |          |
| Change in benefit obligation: <sup>(1)</sup>  |                  |          |          |          |
| Benefit obligation beginning of period        | \$ 2,133         | \$ 1,989 | \$ 642   | \$ 673   |
| Service cost                                  | 19               | 19       |          |          |
| Interest cost                                 | 115              | 121      | 33       | 38       |
| Participant contributions                     |                  |          | 6        | 10       |
| Actuarial (gain) loss                         | 130              | 159      | 28       | (28)     |
| Benefits paid <sup>(2)</sup>                  | (179)            | (171)    | (50)     | (51)     |
| Other   |                  | 16       |          |          |
| Benefit obligation end of period              | \$ 2,218         | \$ 2,133 | \$ 659   | \$ 642   |
| Change in plan assets:                        |                  |          |          |          |
| Fair value of plan assets beginning of period | \$ 1,979         | \$ 1,773 | \$ 243   | \$ 210   |
| Actual return on plan assets <sup>(3)</sup>   | 244              | 373      | 22       | 37       |
| Employer contributions                        | 4                | 4        | 49       | 44       |
| Participant contributions                     |                  |          | 6        | 9        |
| Benefits paid                                 | (179)            | (171)    | (55)     | (57)     |
| Fair value of plan assets end of period       | \$ 2,048         | \$ 1,979 | \$ 265   | \$ 243   |
| Reconciliation of funded status:              |                  |          |          |          |
| Fair value of plan assets                     | \$ 2,048         | \$ 1,979 | \$ 265   | \$ 243   |
| Less: Benefit obligation                      | 2,218            | 2,133    | 659      | 642      |
| Net liability at December 31                  | \$ (170)         | \$ (154) | \$ (394) | \$ (399) |

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

(2) Amounts for other postretirement benefits are shown net of a subsidy of approximately \$5 million and \$6 million for each of the years ended December 31, 2010 and 2009 related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

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

*Components of Funded Status.* The following table details the amounts recognized in our balance sheet at December 31, 2010 and 2009 related to our pension and OPEB plans.

| Pension Benefits |      | OPEB |      |
|------------------|------|------|------|
| 2010             | 2009 | 2010 | 2009 |

|                               | <b>(In millions)</b> |          |          |          |
|-------------------------------|----------------------|----------|----------|----------|
| Non-current benefit asset     | \$                   | \$       | \$ 106   | \$ 88    |
| Current benefit liability     | (4)                  | (5)      | (40)     | (39)     |
| Non-current benefit liability | (166)                | (149)    | (460)    | (448)    |
| Funded status                 | \$ (170)             | \$ (154) | \$ (394) | \$ (399) |

---

**Table of Contents**

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

|   | <b>Pension Benefits</b> |             | <b>OPEB</b> |             |
|---|-------------------------|-------------|-------------|-------------|
|   | <b>2010</b>             | <b>2009</b> | <b>2010</b> | <b>2009</b> |
|   | <b>(In millions)</b>    |             |             |             |
| Unrecognized net gain (loss)                  | \$ (689)                | \$ (709)    | \$ 23       | \$ 43       |
| Unamortized prior service cost                | (16)                    | (16)        |             |             |
| Accumulated other comprehensive income (loss) | \$ (705)                | \$ (725)    | \$ 23       | \$ 43       |

We anticipate that approximately \$60 million of our accumulated other comprehensive loss, net of tax, will be recognized as part of our net periodic benefit cost in 2011.

Our accumulated benefit obligation for our defined benefit pension plans was \$2.2 billion and \$2.1 billion at December 31, 2010 and 2009. Our accumulated benefit obligation for our defined benefit pension plans, whose accumulated benefit obligations exceeded the fair value of plan assets, was \$2.2 billion and \$2.1 billion as of December 31, 2010 and 2009. The fair value of these plans' assets was approximately \$2.0 billion at December 31, 2010 and 2009.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was \$558 million and \$542 million as of December 31, 2010 and 2009. The fair value of these plans' assets was \$58 million and \$55 million at December 31, 2010 and 2009.

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

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

Level 1 assets' fair values are based on quoted prices in actively traded markets. Included in this level are equity securities, fixed income securities, an exchange traded mutual fund and other securities.

Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are common collective trust funds, mutual funds and certain fixed income securities. The common collective trust funds and mutual funds' fair values are primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. For common collective trust funds and mutual funds, certain restrictions on redemption exist as of December 31, 2010 where the issuer reserves the right to temporarily delay withdrawal in certain situations such as market

conditions or at the issuer's discretion. The fixed income securities fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market.

**Table of Contents**

Level 3 assets' fair values are similar to Level 2 assets and are also subject to additional restrictions associated with the timing of redemption which extend beyond 90 days as of December 31, 2010. Included in this level is a mutual fund whose fair value is primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value classified in each level at December 31, 2010 and 2009 (in millions):

|  | <b>Pension Assets</b> |                 |                    |                 |                    |                 |                 |
|--|-----------------------|-----------------|--------------------|-----------------|--------------------|-----------------|-----------------|
|  | <b>2010</b>           |                 |                    | <b>2009</b>     |                    |                 |                 |
|  | <b>Level<br/>1</b>    | <b>Level 2</b>  | <b>Level<br/>3</b> | <b>Total</b>    | <b>Level<br/>1</b> | <b>Level 2</b>  | <b>Total</b>    |
| Interest bearing cash                        | \$ 1                  | \$              | \$                 | \$ 1            | \$                 | \$              | \$              |
| Equity securities:                           |                       |                 |                    |                 |                    |                 |                 |
| Domestic companies                           | 582                   |                 |                    | 582             | 480                |                 | 480             |
| Foreign companies                            | 107                   |                 |                    | 107             | 83                 |                 | 83              |
| Fixed income securities:                     |                       |                 |                    |                 |                    |                 |                 |
| U.S. treasuries                              | 66                    |                 |                    | 66              | 76                 |                 | 76              |
| Corporate bonds                              | 49                    |                 |                    | 49              | 46                 |                 | 46              |
| Federal mortgage-backed and other            | 27                    | 4               |                    | 31              | 19                 |                 | 19              |
| Common collective trust funds <sup>(1)</sup> |                       | 1,051           |                    | 1,051           |                    | 1,223           | 1,223           |
| Mutual funds <sup>(2)</sup>                  |                       | 122             | 39                 | 161             |                    | 51              | 51              |
| Other investments                            |                       |                 |                    |                 | 1                  |                 | 1               |
| <b>Total assets at fair value</b>            | <b>\$ 832</b>         | <b>\$ 1,177</b> | <b>\$ 39</b>       | <b>\$ 2,048</b> | <b>\$ 705</b>      | <b>\$ 1,274</b> | <b>\$ 1,979</b> |

(1) For 2010, this category includes common collective trust funds which are invested in approximately 51 percent fixed income, 46 percent equity and other and 3 percent short term securities. For 2009, this category includes common collective trust funds which are invested in approximately 54 percent fixed income, 43 percent equity, and 3 percent short term securities.

(2) For 2010, this category includes mutual funds which are invested in approximately 59 percent hedge funds and approximately 41 percent fixed income. For 2009, this category includes a mutual fund that is substantially invested in fixed income.

|   | <b>OPEB Assets</b> |                |               |                    |                |               |
|---|--------------------|----------------|---------------|--------------------|----------------|---------------|
|   | <b>2010</b>        |                |               | <b>2009</b>        |                |               |
|   | <b>Level<br/>1</b> | <b>Level 2</b> | <b>Total</b>  | <b>Level<br/>1</b> | <b>Level 2</b> | <b>Total</b>  |
| Exchange traded mutual fund                     | \$ 12              | \$             | \$ 12         | \$ 12              | \$             | \$ 12         |
| Common collective trust funds<br><sup>(1)</sup> |                    | 253            | 253           |                    | 231            | 231           |
| <b>Total assets at fair value</b>               | <b>\$ 12</b>       | <b>\$ 253</b>  | <b>\$ 265</b> | <b>\$ 12</b>       | <b>\$ 231</b>  | <b>\$ 243</b> |

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

The following table presents the changes in our pension plan asset included in Level 3 for the year ended December 31, 2010 (in millions):

|             | <b>Balance<br/>at<br/>Beginning<br/>of Period</b> | <b>Unrealized<br/>gains</b> | <b>Purchases</b> | <b>Balance<br/>at<br/>End of<br/>Period</b> |
|-------------|---|-----------------------------|------------------|---|
| Mutual fund | \$  | \$ 1                        | \$ 38            | \$ 39                                       |

*Expected Payment of Future Benefits.* As of December 31, 2010, we expect the following benefit payments under our plans:

| <b>Year Ending December 31,</b> | <b>Pension<br/>Benefits</b> | <b>OPEB<sup>(1)</sup></b> |
|---------------------------------|-----------------------------|---------------------------|
|                                 | <b>(In millions)</b>        |                           |
| 2011                            | \$184                       | \$ 56                     |
| 2012                            | 184                         | 56                        |
| 2013                            | 185                         | 55                        |
| 2014                            | 184                         | 55                        |
| 2015                            | 183                         | 54                        |
| 2016-2020                       | 890                         | 248                       |

<sup>(1)</sup> Includes a reduction of approximately \$7 million in each of the years 2011-2015 and approximately \$33 million in aggregate for 2016-2020 for an expected subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

**Table of Contents**

*Actuarial Assumptions and Sensitivity Analysis.* Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation as of December 31, 2010, 2009 and 2008 and net benefit costs of our pension and OPEB plans for 2010, 2009 and 2008:

|   | Pension Benefits |                   |      | 2010 | OPEB |                   |
|---|------------------|-------------------|------|------|------|-------------------|
|   | 2010             | 2009<br>(Percent) | 2008 |      | 2010 | 2009<br>(Percent) |
| Assumptions related to benefit obligations:   |                  |                   |      |      |      |                   |
| Discount rate                                 | 5.01             | 5.61              | 6.33 | 4.83 | 5.42 | 5.98              |
| Rate of compensation increase                 | 4.09             | 4.20              | 4.18 |      |      |                   |
| Assumptions related to benefit costs:         |                  |                   |      |      |      |                   |
| Discount rate                                 | 5.61             | 6.33              | 6.25 | 5.42 | 5.98 | 6.05              |
| Expected return on plan assets <sup>(1)</sup> | 8.00             | 8.00              | 8.00 | 7.75 | 8.00 | 8.00              |
| Rate of compensation increase                 | 4.20             | 4.18              | 4.27 |      |      |                   |

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

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 7.4 percent, gradually decreasing to 5.0 percent by the year 2016. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2010 and 2009:

|   | 2010<br>(In millions) | 2009<br>(In millions) |
|---|-----------------------|-----------------------|
| One percentage point increase:                |                       |                       |
| Aggregate of service cost and interest cost   | \$ 3                  | \$ 3                  |
| Accumulated postretirement benefit obligation | 49                    | 47                    |
| One percentage point decrease:                |                       |                       |
| Aggregate of service cost and interest cost   | \$ (2)                | \$ (3)                |
| Accumulated postretirement benefit obligation | (43)                  | (42)                  |

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

|   | Pension Benefits |       |         | 2010  | OPEB  |       |
|---|------------------|-------|---------|-------|-------|-------|
|   | 2010             | 2009  | 2008    |       | 2010  | 2009  |
|   | (In millions)    |       |         |       |       |       |
| Service cost                                | \$ 19            | \$ 19 | \$ 15   | \$    | \$    | \$    |
| Interest cost                               | 115              | 121   | 120     | 33    | 38    | 38    |
| Expected return on plan assets              | (157)            | (172) | (187)   | (13)  | (12)  | (17)  |
| Amortization of net actuarial loss (gain)   | 73               | 45    | 24      | (3)   |       | (5)   |
| Amortization of prior service cost (credit) | 1                | (1)   | (2)     |       | (1)   | (1)   |
| Net benefit cost (income)                   | \$ 51            | \$ 12 | \$ (30) | \$ 17 | \$ 25 | \$ 15 |

*Components of Other Comprehensive Income (Loss).* The following table details the amounts recognized in our other comprehensive loss, net of income taxes, for the years ended December 31, 2010, 2009, and 2008 related to our

pension and OPEB plans.

|   | <b>Pension Benefits</b> |             |             |             | <b>OPEB</b> |             |
|---|-------------------------|-------------|-------------|-------------|-------------|-------------|
|   | <b>2010</b>             | <b>2009</b> | <b>2008</b> | <b>2010</b> | <b>2009</b> | <b>2008</b> |
|   | <b>(In millions)</b>    |             |             |             |             |             |
| Prior service cost                          | \$                      | \$ (10)     | \$ (11)     | \$          | \$          | \$          |
| Net gain (loss)                             | (28)                    | 27          | (509)       | (18)        | 19          | (7)         |
| Amortization of net actuarial loss (gain)   | 47                      | 29          | 20          | (2)         |             | (1)         |
| Amortization of prior service cost (credit) | 1                       | (1)         | (2)         |             | (1)         | (1)         |
| Other comprehensive income (loss)           | \$ 20                   | \$ 45       | \$ (502)    | \$ (20)     | \$ 18       | \$ (9)      |

**Table of Contents****14. Equity and Preferred Stock of Subsidiaries**

*Convertible Perpetual Preferred Stock.* We have \$750 million of convertible perpetual preferred stock outstanding. Dividends on the preferred stock are declared and approved quarterly and accumulate if not paid. Each share of the preferred stock is convertible at the holder's option, at any time, subject to adjustment, into 77.2295 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of \$12.95 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or payment of dividends on our common stock in excess of a specified rate.

*Common and Preferred Stock Dividends.* The table below shows the amount of dividends declared and paid (dollars in millions):

|                                   | <b>Common<br/>Stock<br/>(\$0.01/Share)</b> | <b>Convertible Preferred<br/>Stock<br/>(4.99%/Year)</b> |
|-----------------------------------|--|---|
| Amount paid in 2010               | \$ 28                                      | \$ 37   |
| Amount paid in January 2011       | \$ 7                                       | \$ 9  |
| Declared in 2011:                 |  |   |
| Date of declaration               | February 8,<br>2011                        | February 8, 2011  |
| Payable to shareholders on record | March 4,<br>2011                           | March 15, 2011  |
| Date payable                      | April 1, 2011                              | April 1, 2011   |

Dividends on our common stock and preferred stock are treated as reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common and preferred stock in 2010 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock provide for the conversion ratio on our preferred stock to increase when we pay quarterly dividends to our common shareholders in excess of \$0.04 per share. The terms of these preferred shares also prohibit the payment of dividends on our common stock unless we have paid or set aside for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restriction on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If we are unable to comply with our fixed charge ratio, our ability to pay additional dividends would be restricted.

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

|   | <b>2010</b> | <b>2009</b> |
|---|-------------|-------------|
| Cash flow hedges  | \$ (69)     | \$ (36)     |
| Pension and other postretirement benefits (see Note 13)         | (682)       | (682)       |
| Total accumulated other comprehensive loss, net of income taxes | \$ (751)    | \$ (718)    |

*Noncontrolling Interests.* We are the general partner of EPB, a master limited partnership (MLP), formed in 2007. As of December 31, 2010, we hold a 2 percent general partner interest and a 49 percent limited partner interest (comprised of both common and subordinated units) in the partnership. During the years ended December 31, 2010, 2009, and 2008 we issued noncontrolling interests, net of issuance costs, of \$1.3 billion, \$212 million, and \$15 million in conjunction with the contribution to EPB of additional ownership interests in CIG and SNG and 100 percent ownership interests in Southern LNG Company, L.L.C. (SLNG), which owns the Elba Island LNG receiving terminal,

and El Paso Elba Express Company, L.L.C. (Elba Express), which owns the Elba Express Pipeline. To the extent that the consideration paid for by EPB to us for the sales of pipeline assets to EPB is not in the form of additional equity in EPB, then our interest in our pipeline assets will become diluted over time.

**Table of Contents**

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

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

For additional information regarding our master limited partnership, see *net income attributable to noncontrolling interests* in the table below and Note 11.

*Preferred Stock of Subsidiaries.* During 2009, Global Infrastructure Partners (GIP), our partner on our Ruby pipeline project, contributed \$145 million to our subsidiary, Ruby Pipeline Holding Company, L.L.C. (Ruby) and received a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains Investment Company, L.L.C. (Cheyenne Plains). GIP earns a 15 percent dividend on its preferred interests in Cheyenne Plains. In addition, GIP provided a \$405 million loan for Ruby project funding. During 2010, GIP's loan of \$405 million was converted to a convertible preferred equity interest in Ruby. In addition, GIP provided an additional \$120 million contribution for a convertible preferred equity interest in Ruby. GIP will earn a 13 percent return on its convertible preferred interests in Ruby beginning on the earlier of the date the pipeline project is placed in service or August 2011. For a further discussion of the Ruby transaction, see Note 17.

The convertible preferred equity interests in Cheyenne Plains and Ruby have been classified between liabilities and equity on our balance sheet since the events that require redemption of the preferred interests are not entirely within our control and are not certain to occur. We paid preferred dividends of \$21 million on GIP's preferred interest in Cheyenne Plains for the year ended December 31, 2010. Also, for the year ended December 31, 2010, we recognized a return of \$27 million on GIP's preferred interest in Ruby. Both the preferred dividends and the return on GIP's preferred interests are reflected in net income attributable to noncontrolling interests on our income statement.

The components of net income attributable to noncontrolling interests on our statements of income for the year ended December 31, are as follows (in millions):

|   | <b>2010</b> | <b>2009</b> | <b>2008</b> |
|---|-------------|-------------|-------------|
| EPB   | \$ 118      | \$ 60       | \$ 34       |
| Preferred Stock of Cheyenne Plains                  | 21          | 5           |             |
| Preferred Stock of Ruby                             | 27          |             |             |
| Net income attributable to noncontrolling interests | \$ 166      | \$ 65       | \$ 34       |

**Table of Contents****15. Stock-Based Compensation**

*Overview.* Under our stock-based compensation plans, we may issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. We are authorized to grant awards of approximately 62 million shares of our common stock under our current plans, which includes 54.5 million shares under our Omnibus plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At December 31, 2010, approximately 23.5 million shares remain available for grant under our current plans, which includes approximately 19.8 million shares under our Omnibus plan, 1.6 million shares under our non-employee director plan and 2.1 million shares under our employee stock purchase plan. We also have approximately 10 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

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

*Non-Qualified Stock Options.* We grant non-qualified stock options to our employees at an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally have vested in equal amounts over three years from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the year ended December 31, 2010 is presented below:

|  | # Shares<br>Underlying<br>Options | Weighted<br>Average<br>Exercise<br>Price<br>per Share | Weighted<br>Average<br>Remaining<br>Contractual<br>Term<br>(In years) | Aggregate<br>Intrinsic<br>Value<br>(In<br>millions) |
|--|-----------------------------------|---|---|---|
| Outstanding at December 31, 2009                                 | 29,004,240                        | \$21.87   |   |   |
| Granted  | 6,625,718                         | \$11.09   |   |   |
| Exercised  | (1,069,337)                       | \$ 7.86   |   |   |
| Forfeited or canceled  | (995,351)                         | \$ 9.68   |   |   |
| Expired  | (1,336,869)                       | \$43.92   |   |   |
| Outstanding at December 31, 2010                                 | 32,228,401                        | \$19.58   | 5.78  | \$ 89   |
| Vested at December 31, 2010 or expected to vest<br>in the future | 31,616,912                        | \$19.77   | 5.72  | \$ 87   |
| Exercisable at December 31, 2010                                 | 19,998,624                        | \$25.46   | 4.01  | \$ 39   |

During 2010, 2009 and 2008, we recognized approximately \$24 million, \$23 million and \$21 million of pre-tax compensation expense on stock options, capitalized approximately \$4 million, \$5 million, and \$4 million of this expense as part of fixed assets and recorded \$8 million, \$8 million and \$7 million of income tax benefits, respectively. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2010 was approximately \$19 million, which is expected to be recognized over a weighted average period of 10 months. Options exercised during the years ended December 31, 2010, 2009 and 2008 had a total intrinsic value of \$5 million, less than \$1 million and \$10 million, generated \$8 million, \$1 million and \$11 million of cash proceeds and did not generate

any significant associated income tax benefit.

**Table of Contents**

*Fair Value Assumptions.* The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management's best estimate at the time of grant. For the years ended December 31, 2010, 2009 and 2008 the weighted average grant date fair value per share of options granted was \$4.55, \$2.96 and \$5.73.

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

|                         | 2010 | 2009 | 2008 |
|-------------------------|------|------|------|
| Expected Term in Years  | 6.0  | 6.0  | 6.0  |
| Expected Volatility     | 40%  | 54%  | 35%  |
| Expected Dividends      | 0.5% | 1.5% | 1.0% |
| Risk-Free Interest Rate | 2.9% | 2.0% | 2.8% |

We estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and from our historical stock price volatility over the expected term, adjusted for certain time periods that we believe are not representative of future stock performance. We estimate the expected term of our option awards based on the vesting period and average remaining contractual term, referred to as the "simplified method". We use this method to provide a reasonable basis for estimating our expected term based on insufficient historical data prior to 2006 primarily due to significant changes in the composition of our employees receiving stock-based compensation awards.

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

|                                |                 | Weighted Average<br>Grant Date Fair<br>Value |
|--------------------------------|-----------------|--|
| <b>Nonvested Shares</b>        | <b># Shares</b> | <b>per Share</b>                             |
| Nonvested at December 31, 2009 | 4,943,319       | \$ 10.08                                     |
| Granted                        | 2,836,570       | \$ 11.09                                     |
| Vested                         | (2,381,583)     | \$ 11.51                                     |
| Forfeited                      | (379,374)       | \$ 9.56                                      |
| Nonvested at December 31, 2010 | 5,018,932       | \$ 10.01                                     |

The weighted average grant date fair value per share for restricted stock granted during 2010, 2009 and 2008 was \$11.09, \$6.53 and \$15.46. The total fair value of shares vested during 2010, 2009 and 2008 was \$27 million, \$13 million and \$29 million.

During 2010, 2009 and 2008, we recognized approximately \$25 million, \$26 million and \$29 million of pre-tax compensation expense on our restricted share awards, capitalized approximately \$4 million, \$7 million and \$7 million of this expense as part of fixed assets and recorded \$9 million, \$9 million and \$10 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2010 was approximately \$19 million, which is expected to be recognized over a weighted average period of 10 months.

*Employee Stock Purchase Plan.* Our employee stock purchase plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of current stock compensation accounting standards. Shares issued under this plan were insignificant during 2010, 2009 and 2008.



**Table of Contents****16. Business Segment Information**

As of December 31, 2010, our business consists of two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Prior to 2010, we also had a Power segment which has been combined into our corporate and other activities for all periods presented. A further discussion of each segment and our corporate and other activities follows.

*Pipelines.* Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. As of December 31, 2010, we conducted our activities primarily through eight wholly or majority owned interstate pipeline systems and equity interests in two transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in three underground natural gas storage facilities and two LNG terminalling facilities, one of which is under construction.

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

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

*Corporate and Other.* Our corporate and other activities include our general and administrative functions, our emerging midstream business, our remaining power operations, and other miscellaneous businesses.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2010, 2009 and 2008.

Our management uses earnings before interest expense and income taxes (EBIT) as a measure to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to evaluate more effectively the operating performance using the same performance measure analyzed internally by our management and so that our investors may evaluate our operating results without regard to our financing methods or capital structure. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense, (ii) income taxes, and (iii) net income attributable to noncontrolling interests. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income (loss), income (loss) before income taxes and other performance measures such as operating income or operating cash flows. Below is a reconciliation of our EBIT to our net income (loss) for the periods ended December 31:

|   | <b>2010</b> | <b>2009</b>          | <b>2008</b> |
|---|-------------|----------------------|-------------|
|   |             | <b>(In millions)</b> |             |
| EBIT  | \$ 2,175    | \$ 70                | \$ (154)    |
| Interest and debt expense                             | (1,031)     | (1,008)              | (914)       |
| Income tax benefit (expense)                          | (386)       | 399                  | 245         |
| Net income (loss) attributable to El Paso Corporation | 758         | (539)                | (823)       |
| Net income attributable to non-controlling interests  | 166         | 65                   | 34          |
| Net income (loss)                                     | \$ 924      | \$ (474)             | \$ (789)    |

**Table of Contents**

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

|   | <b>As of or for the Year Ended December 31, 2010</b> |   |   |  | <b>Total</b> |
|---|--|---|---|--|--------------|
|   | <b>Pipelines</b>                                     | <b>Segment<br/>Exploration<br/>and<br/>Production</b> | <b>Marketing<br/><br/>(In millions)</b> | <b>Corporate<br/>and<br/>Other<sup>(1)</sup></b> |              |
| Revenue from external customers   |  |   |   |  |              |
| Domestic  | \$ 2,768   | \$ 957 <sup>(2)</sup>                                 | \$ 597                                  | \$ 62  | \$ 4,384     |
| Foreign   | 3  | 86  | 143                                     |  | 232          |
| Intersegment revenue  | 49   | 746 <sup>(2)</sup>                                    | (789)                                   | (6)  |              |
| Operation and maintenance   | 785  | 384   | 2                                       | 64   | 1,235        |
| Ceiling test charges  |  | 25  |   |  | 25           |
| (Gain) loss on long-lived assets <sup>(3)</sup>   | 30   |   |   | (113)  | (83)         |
| Depreciation, depletion and amortization  | 440  | 477   |   | 25   | 942          |
| Loss on debt extinguishment   |  |   |   | (217)  | (217)        |
| Earnings (losses) from unconsolidated affiliates  | 178 <sup>(4)</sup>                                   | (7)   |   | 17   | 188          |
| EBIT  | 1,572  | 727   | (50)                                    | (74)   | 2,175        |
| Assets  |  |   |   |  |              |
| Domestic  | 19,642   | 4,243   | 200                                     | 532  | 24,617       |
| Foreign <sup>(5)</sup>  | 9  | 414   | 22                                      | 208  | 653          |
| Investments in unconsolidated affiliates  | 1,127  | 399   |   | 147  | 1,673        |
| Capital expenditures and investments in and advances to unconsolidated affiliates, net <sup>(6)</sup> | 2,547  | 1,380   |   | 79   | 4,006        |

- (1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$24 million and an operation and maintenance expense elimination of \$1 million in the Corporate and Other column to remove intersegment transactions.
- (2) Revenues from external customers include gains of \$390 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.
- (3) Includes a \$110 million gain in Corporate and Other related to our sale of midstream assets into our newly formed joint venture and \$21 million non-cash asset write down in Pipelines based on a FERC order related to the sale of a compressor station and gas processing plant in 2009.
- (4) Includes a gain of approximately \$80 million related to the sale of our interests in certain Mexican pipeline and compression assets.
- (5) Of total foreign assets, approximately \$0.4 billion relates to property, plant and equipment, and approximately \$0.1 billion relates to investments in and advances to unconsolidated affiliates.

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

**Table of Contents**

|   | <b>As of or for the Year Ended December 31, 2009</b> |                         |                                    |  |              |
|---|--|-------------------------|------------------------------------|--|--------------|
|   | <b>Segment<br/>Exploration<br/>and</b>               |                         |                                    | <b>Corporate<br/>and<br/>Other<sup>(1)</sup></b> | <b>Total</b> |
|   | <b>Pipelines</b>                                     | <b>Production</b>       | <b>Marketing<br/>(In millions)</b> |  |              |
| Revenue from external customers   |  |                         |                                    |  |              |
| Domestic  | \$ 2,711   | \$ 1,257 <sup>(2)</sup> | \$ 497                             | \$ 17  | \$ 4,482     |
| Foreign   | 10   | 26                      | 114                                |  | 150          |
| Intersegment revenue  | 46   | 545 <sup>(2)</sup>      | (582)                              | (10)   | (1)          |
| Operation and maintenance   | 807  | 392                     | 8                                  | 28   | 1,235        |
| Ceiling test charges  |  | 2,123                   |                                    |  | 2,123        |
| (Gain) loss on long-lived assets  | (2)  | 25                      |                                    | (1)  | 22           |
| Depreciation, depletion and amortization  | 414  | 440                     |                                    | 13   | 867          |
| Earnings (losses) from unconsolidated affiliates  | 92   | (30)                    |                                    | 5  | 67           |
| EBIT  | 1,416  | (1,349)                 | 20                                 | (17)   | 70           |
| Assets  |  |                         |                                    |  |              |
| Domestic  | 17,090   | 3,574                   | 321                                | 580  | 21,565       |
| Foreign <sup>(3)</sup>  | 234  | 451                     | 24                                 | 231  | 940          |
| Investments in unconsolidated affiliates  | 1,133  | 456                     |                                    | 129  | 1,718        |
| Capital expenditures and investments in and advances to unconsolidated affiliates, net <sup>(4)</sup> | 1,710  | 1,154                   |                                    | (110)  | 2,754        |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$10 million.

(2) Revenues from external customers include gains of \$687 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

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

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

**Table of Contents**

|  | <b>As of or for the Year Ended December 31, 2008</b> |   |                  |  |              |
|--|--|---|------------------|--|--------------|
|  | <b>Segments</b>                                      |   |                  |  |              |
|  | <b>Pipelines</b>                                     | <b>Exploration<br/>and<br/>Production</b> | <b>Marketing</b> | <b>Corporate<sup>(1)</sup><br/>and Other</b> | <b>Total</b> |
|  | <b>(In millions)</b>                                 |   |                  |  |              |
| Revenue from external customers  |  |   |                  |  |              |
| Domestic   | \$ 2,621   | \$ 1,317 <sup>(2)</sup>                   | \$ 1,137         | \$ 9   | \$ 5,084     |
| Foreign  | 11   | 22  | 237              | 9  | 279          |
| Intersegment revenue   | 52   | 1,423 <sup>(2)</sup>                      | (1,457)          | (18)   |              |
| Operation and maintenance  | 824  | 404                                       | 19               | (61)   | 1,186        |
| Ceiling test charges   |  | 2,669                                     |                  |  | 2,669        |
| (Gain) loss on long-lived assets   | 39   |   |                  | (35)   | 4            |
| Depreciation, depletion and amortization   | 395  | 799                                       |                  | 11   | 1,205        |
| Earnings (losses) from unconsolidated affiliates   | 97   | (93)                                      |                  | 44   | 48           |
| EBIT   | 1,273  | (1,448)                                   | (104)            | 125  | (154)        |
| Assets   |  |   |                  |  |              |
| Domestic   | 14,917   | 5,821                                     | 444              | 1,494  | 22,676       |
| Foreign <sup>(3)</sup>   | 204  | 321                                       | 21               | 446  | 992          |
| Investments in unconsolidated affiliates   | 1,054  | 531                                       |                  | 118  | 1,703        |
| Capital expenditures, and investments in and advances to unconsolidated affiliates, net <sup>(4)</sup> | 1,457  | 1,622                                     |                  | 27   | 3,106        |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$19 million.

(2) Revenues from external customers include gains of \$196 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Of total foreign assets, approximately \$0.3 billion relates to property, plant and equipment and approximately \$0.5 billion relates to investments in and advances to unconsolidated affiliates.

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

**Table of Contents****17. Variable Interest Entities and Accounts Receivable Sales Programs**

*Ruby.* We consolidate our investment in Ruby, a variable interest entity that owns our Ruby pipeline project, as its primary beneficiary. In July 2009, we entered into an agreement with GIP whereby they agreed to invest up to \$700 million and acquire a 50 percent equity interest in Ruby subject to certain conditions. As part of this agreement, GIP (i) contributed \$145 million in exchange for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains (a variable interest entity that we also consolidate as its primary beneficiary) and (ii) provided a \$405 million loan for Ruby project funding.

In 2010, we entered into a \$1.5 billion third party project financing facility, received a BLM right-of-way grant, received final approval from the FERC, and began construction of the Ruby pipeline. Several groups have filed appeals of certain approvals and actions of the BLM and the U.S. Fish and Wildlife Service related to the project. We are currently unable to predict what action, if any, the courts will take in response to these appeals or any subsequent filings that may be made by one or more of these groups.

During 2010, GIP's loan of \$405 million was converted to a convertible preferred equity interest in Ruby, GIP provided an additional \$120 million contribution for a convertible preferred equity interest in Ruby, and we borrowed approximately \$1.1 billion under the \$1.5 billion facility.

GIP will hold its interest in Cheyenne Plains until certain conditions are satisfied, including placing the Ruby pipeline project in service. GIP has the right to convert its preferred equity in Ruby to common equity in Ruby at any time; however, the preferred equity is subject to mandatory conversion to Ruby common equity upon the satisfaction of certain conditions, including Ruby entering into certain additional firm transportation agreements.

If all conditions to closing are satisfied or waived, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, if certain conditions are not satisfied including placing the Ruby pipeline project in service by November 2011, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining investments in Cheyenne Plains and Ruby including a 15 percent return on its investments in Cheyenne Plains and Ruby. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and 50 million common units we own in EPB.

For additional information on our Ruby project financing, see Note 11.

*Other.* We also hold interests in other variable interest entities that we account for as investments in unconsolidated affiliates. These entities do not have significant operations and accordingly do not have a material impact to our financial statements.

*Accounts Receivable Sales Program.* During 2009, several of our pipeline subsidiaries had agreements to sell senior interests in certain of their accounts receivable (which are short-term assets that generally settle within 60 days) to a third party financial institution (through wholly-owned special purpose entities), and we retained subordinated interests in those receivables. The sale of these senior interests qualified for sale accounting and was conducted to accelerate cash from these receivables, the proceeds from which were used to increase liquidity and lower our overall cost of capital. During the years ended December 31, 2009 and 2008, we received \$987 million and \$862 million of cash related to the sale of the senior interests, collected \$869 million and \$977 million from the subordinated interests we retained in the receivables, and recognized a loss of approximately \$2 million and \$3 million on these transactions. At December 31, 2009, the third party financial institution held \$90 million of senior interests and we held \$79 million of subordinated interests. Our subordinated interests were reflected in accounts receivable on our balance sheet. In January 2010, we terminated these accounts receivable sales programs and paid \$90 million to acquire the senior interests. We reflected the cash flows related to the accounts receivable sold under this program, changes in our retained subordinated interests, and cash paid to terminate the programs, as operating cash flows on our statement of cash flows.

In the first quarter of 2010, we entered into new accounts receivable sales programs to continue to sell accounts receivable to the third party financial institution that qualify for sale accounting under the updated accounting standards related to financial asset transfers, and to include an additional pipeline subsidiary's accounts receivable in the program. Under these programs, several of our pipeline subsidiaries sell receivables in their entirety to the third-party financial institution (through wholly-owned special purpose entities). At December 31, 2010, the

third-party financial institution held \$210 million of the accounts receivable we sold under the program. In connection with our

**Table of Contents**

accounts receivable sales, we receive a portion of the sales proceeds up front and receive an additional amount upon the collection of the underlying receivables (which we refer to as a deferred purchase price). Our ability to recover the deferred purchase price is based solely on the collection of the underlying receivables. During the year ended December 31, 2010, we sold approximately \$2.5 billion of accounts receivable to the third-party financial institution, for which we received approximately \$1.5 billion of cash up front and had a deferred purchase price of approximately \$1.0 billion. We received approximately \$967 million of cash related to the deferred purchase price when the underlying receivables were collected during 2010. As of December 31, 2010, we had not collected approximately \$89 million of deferred purchase price related to our accounts receivable sales, which is reflected as other accounts receivable on our balance sheet (and was initially recorded at an amount which approximates its fair value as a Level 2 measurement). We recognized a loss of approximately \$2 million on our accounts receivable sales during the year ended December 31, 2010. Because the cash received up front and the deferred purchase price relate to the sale or ultimate collection of the underlying receivables, and are not subject to significant other risks given their short term nature, we reflect all cash flows under the new accounts receivable sales programs as operating cash flows on our statement of cash flows.

Under both the prior and current accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the periods ended December 31, 2010, 2009 and 2008.

The third party financial institution involved in both of these accounts receivable sales programs acquires interests in various financial assets and issues commercial paper to fund those acquisitions. We do not consolidate the third party financial institution because we do not have the power to control, direct, or exert significant influence over its overall activities since our receivables do not comprise a significant portion of its operations.

**Table of Contents****18. Investments in, Earnings from and Transactions with Unconsolidated Affiliates**

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. The earnings from unconsolidated affiliates reflected in our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments, gains and losses on divestitures and other adjustments recorded by us. As of December 31, 2010 and 2009, our investment balance exceeded the net equity in the underlying net assets of these investments by \$98 million and \$269 million due primarily to purchase price adjustments, net of impairment charges, recorded by us. The majority of our purchase price adjustments is related to our investment in Four Star. We amortize and generally assess the recoverability of this amount based on the development and production of the underlying estimated proved natural gas and oil reserves of Four Star. The information below related to our unconsolidated affiliates includes (i) our net investment and earnings (losses) we recorded from these investments, (ii) summarized financial information of our proportionate share of these investments, and (iii) revenues and charges with our unconsolidated affiliates. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the years ended December 31:

|  | Net Ownership Interest |         | Investment    |          | Earnings (Losses) from Unconsolidated Affiliates |         |         |
|--|------------------------|---------|---------------|----------|--|---------|---------|
|  | 2010                   | 2009    | 2010          | 2009     | 2010   | 2009    | 2008    |
|  | (Percent)              |         | (In millions) |          | (In millions)                                    |         |         |
| Four Star <sup>(1)</sup>               | 49                     | 49      | \$ 393        | \$ 450   | \$ (7)   | \$ (30) | \$ (93) |
| Citrus                                 | 50                     | 50      | 822           | 630      | 92   | 66      | 64      |
| Gulf LNG <sup>(2)</sup>                | 50                     | 50      | 266           | 285      | (5)  | (2)     |         |
| Bolivia to Brazil Pipeline             | 8                      | 8       | 104           | 105      | 12   | (2)     | 25      |
| Gasoductos de Chihuahua <sup>(3)</sup> |                        | 50      |               | 184      | 88   | 25      | 29      |
| Other                                  | various                | various | 88            | 64       | 8  | 10      | 23      |
| Total                                  |                        |         | \$ 1,673      | \$ 1,718 | \$ 188   | \$ 67   | \$ 48   |

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of \$38 million for the year ended December 31, 2010, \$48 million for the year ended December 31, 2009, and \$53 million for the year ended December 31, 2008. In 2008, we recorded a \$125 million impairment of the carrying value of our investment based on a decrease in its fair value that resulted from declining commodity prices.

(2) As of December 31, 2010 and 2009, we had outstanding advances and receivables of \$83 million and \$56 million, not included above, related to our investment in Gulf LNG.

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

As of December 31, 2010, approximately \$0.6 billion of the equity in undistributed earnings of 50 percent or less owned entities accounted for by the equity method was included in our consolidated accumulated deficit. We received distributions and dividends from our unconsolidated affiliates of \$64 million, \$90 million and \$182 million for the years ended December 31, 2010, 2009 and 2008. Included in these amounts are returns of capital of less than \$1 million in 2010 and \$2 million in 2009 and 2008. During 2010, we made a capital contribution of \$100 million to Citrus, one of our unconsolidated affiliates.

**Table of Contents**

Below is summarized financial information of our proportionate share of the operating results and financial position of our unconsolidated affiliates.

|                               | <b>Year Ended December 31,</b> |             |             |
|-------------------------------|--------------------------------|-------------|-------------|
|                               | <b>2010</b>                    | <b>2009</b> | <b>2008</b> |
|                               | <b>(In millions)</b>           |             |             |
| Operating results data:       |                                |             |             |
| Operating revenues            | \$ 503                         | \$ 526      | \$ 708      |
| Operating expenses            | 269                            | 268         | 331         |
| Net income                    | 149                            | 130         | 220         |
| Financial position data:      |                                |             |             |
| Current assets                | \$ 160                         | \$ 358      | \$ 320      |
| Non-current assets            | 3,842                          | 3,060       | 2,667       |
| Short-term debt               | 14                             | 232         | 141         |
| Other current liabilities     | 192                            | 186         | 100         |
| Long-term debt                | 1,655                          | 1,028       | 858         |
| Other non-current liabilities | 566                            | 523         | 666         |
| Equity in net assets          | 1,575                          | 1,449       | 1,222       |

Our transactions with unconsolidated affiliates were not material in 2010, 2009 and 2008.

*Other Investment-Related Matters.* We currently have outstanding disputes and other matters related to an investment in two Brazilian power plant facilities (Manaus/Rio Negro) formerly owned by us. We have filed lawsuits to collect amounts due to us (approximately \$70 million of Brazilian reais-denominated accounts receivable) by the plant's power purchaser, which are also guaranteed by the purchaser's parent, Eletrobras, Brazil's state-owned utility. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable.

Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately \$78 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants' power purchaser from 1999 to 2001. By agreement, the power purchaser must indemnify our project companies for these ICMS taxes, along with related interest and penalties, and has therefore been defending the projects against this lawsuit. In order to prevent further collection efforts by the tax authorities for this matter, security must be provided for the potential tax liability to the court's satisfaction. The tax authorities and court have rejected the assets pledged by the power purchaser to date, and during 2010 the tax courts blocked certain of El Paso's bank accounts associated with the Rio Negro power plant in order to obtain this security. The power purchaser has appealed the court's decision. If the power purchaser is unable to resolve this tax matter, our ability to collect amounts due to us from the power purchaser could be impacted. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser's parent.

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

**Table of Contents****Supplemental Selected Quarterly Financial Information (Unaudited)**

Financial information by quarter is summarized below.

|   | Quarters Ended |          |              |             | Total   |
|---|----------------|----------|--------------|-------------|---------|
|   | March 31       | June 30  | September 30 | December 31 |         |
| (In millions, except per common share amounts)                              |                |          |              |             |         |
| 2010  |                |          |              |             |         |
| Operating revenues  | \$ 1,401       | \$ 1,018 | \$ 1,213     | \$ 984      | \$4,616 |
| Operating income (loss)   | 760            | 384      | 518          | 381         | 2,043   |
| Earnings from unconsolidated affiliates                                     | 28             | 111      | 28           | 21          | 188     |
| Net income (loss)   | 419            | 186      | 183          | 136         | 924     |
| Net income (loss) attributable to El Paso Corporation                       | 388            | 157      | 142          | 71          | 758     |
| Net income (loss) attributable to El Paso Corporation's common stockholders | 379            | 147      | 133          | 62          | 721     |
| Basic earnings per common share   |                |          |              |             |         |
| Net income (loss) attributable to El Paso Corporation's common stockholders | 0.54           | 0.21     | 0.19         | 0.09        | 1.03    |
| Diluted earnings per common share   |                |          |              |             |         |
| Net income (loss) attributable to El Paso Corporation's common stockholders | 0.51           | 0.21     | 0.19         | 0.09        | 1.00    |
| 2009  |                |          |              |             |         |
| Operating revenues  | \$ 1,484       | \$ 973   | \$ 981       | \$ 1,193    | \$4,631 |
| Operating income (loss)   | (1,269)        | 391      | 329          | 498         | (51)    |
| Earnings from unconsolidated affiliates                                     | 19             | 12       | 11           | 25          | 67      |
| Net income (loss)   | (957)          | 100      | 82           | 301         | (474)   |
| Net income (loss) attributable to El Paso Corporation                       | (969)          | 89       | 67           | 274         | (539)   |
| Net income (loss) attributable to El Paso Corporation's common stockholders | (978)          | 79       | 58           | 265         | (576)   |
| Basic earnings per common share   |                |          |              |             |         |
| Net income (loss) attributable to El Paso Corporation's common stockholders | (1.41)         | 0.11     | 0.08         | 0.38        | (0.83)  |
| Diluted earnings per common share   |                |          |              |             |         |
| Net income (loss) attributable to El Paso Corporation's common stockholders | (1.41)         | 0.11     | 0.08         | 0.36        | (0.83)  |

Below are items affecting comparability of amounts reported in the respective quarters of 2010 and 2009:

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

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

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

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

*December 31, 2009.* We recorded (i) \$151 million of gains related to changes in fair value of our exploration and production financial derivatives, (ii) an \$88 million tax benefit related to the liquidation of foreign entities, (iii) a \$22 million charge related to restructuring costs and (iv) \$38 million in international ceiling test charges.

*September 30, 2009.* We recorded \$87 million of gains related to changes in fair value of our exploration and production financial derivatives.

*June 30, 2009.* We recorded (i) \$55 million of gains related to changes in fair value of our exploration and production financial derivatives, (ii) a \$25 million mark-to-market gain associated with an indemnification in conjunction with the sale of a legacy ammonia facility, (iii) a \$22 million loss on the sale of our Porto Velho notes receivables and (iv) \$21 million in mark-to-market gains on power contracts.

*March 31, 2009.* We recorded (i) a total of \$2.1 billion in domestic and international ceiling test charges, (ii) \$394 million in mark-to-market gains related to changes in fair value of our exploration and production financial derivatives and (iii) \$52 million gain related to the application of accounting standard updates on certain of our derivative liabilities.

**Table of Contents****Supplemental Natural Gas and Oil Operations (Unaudited)**

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

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

|   | U.S.      | Brazil<br>and<br>Egypt <sup>(1)</sup> | Worldwide |
|---|-----------|---------------------------------------|-----------|
| <i>2010 Consolidated:</i>                                     |           |                                       |           |
| Natural gas and oil properties:                               |           |                                       |           |
| Costs subject to amortization                                 | \$ 19,676 | \$ 1,091                              | \$ 20,767 |
| Costs not subject to amortization                             | 537       | 248                                   | 785       |
|   | 20,213    | 1,339                                 | 21,552    |
| Less accumulated depreciation, depletion and amortization     | 16,993    | 902                                   | 17,895    |
| Net capitalized costs   | \$ 3,220  | \$ 437                                | \$ 3,657  |
| <i>2010 Unconsolidated Affiliate Four Star<sup>(2)</sup>:</i> |           |                                       |           |
| Natural gas and oil properties                                | \$ 614    | \$                                    | \$ 614    |
| Less accumulated depreciation, depletion and amortization     | 466       |                                       | 466       |
| Net capitalized costs   | \$ 148    | \$                                    | \$ 148    |
| <i>2009 Consolidated:</i>                                     |           |                                       |           |
| Natural gas and oil properties:                               |           |                                       |           |
| Costs subject to amortization                                 | \$ 19,161 | \$ 1,055                              | \$ 20,216 |
| Costs not subject to amortization                             | 256       | 214                                   | 470       |
|   | 19,417    | 1,269                                 | 20,686    |
| Less accumulated depreciation, depletion and amortization     | 16,921    | 867                                   | 17,788    |
| Net capitalized costs   | \$ 2,496  | \$ 402                                | \$ 2,898  |
| <i>2009 Unconsolidated Affiliate Four Star<sup>(2)</sup>:</i> |           |                                       |           |
| Natural gas and oil properties                                | \$ 594    | \$                                    | \$ 594    |
| Less accumulated depreciation, depletion and amortization     | 436       |                                       | 436       |
| Net capitalized costs   | \$ 158    | \$                                    | \$ 158    |

(1) Capitalized costs for Egypt were \$66 million and \$70 million as of December 31, 2010 and 2009.

(2) Amounts represent our approximate 49 percent equity interest in the underlying oil and gas assets of Four Star. Four Star applies the successful efforts method of accounting for its oil and gas properties.



**Table of Contents**

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

|   | U.S.     | Brazil<br>and<br>Egypt <sup>(1)</sup> | Worldwide |
|---|----------|---------------------------------------|-----------|
| <i>2010 Consolidated:</i>                         |          |                                       |           |
| Property acquisition costs                        |          |                                       |           |
| Proved properties                                 | \$ 51    | \$                                    | \$ 51     |
| Unproved properties                               | 269      |                                       | 269       |
| Exploration costs                                 | 600      | 58                                    | 658       |
| Development costs                                 | 276      | 28                                    | 304       |
| Costs expended                                    | 1,196    | 86                                    | 1,282     |
| Asset retirement obligation costs                 | 7        |                                       | 7         |
| Total costs incurred                              | \$ 1,203 | \$ 86                                 | \$ 1,289  |
| <i>2010 Unconsolidated Affiliate Four States:</i> |          |                                       |           |
| Development costs expended                        | \$ 20    | \$                                    | \$ 20     |
| <i>2009 Consolidated:</i>                         |          |                                       |           |
| Property acquisition costs                        |          |                                       |           |
| Proved properties                                 | \$ 87    | \$                                    | \$ 87     |
| Unproved properties                               | 89       | 51                                    | 140       |
| Exploration costs                                 | 355      | 67                                    | 422       |
| Development costs                                 | 324      | 118                                   | 442       |
| Costs expended                                    | 855      | 236                                   | 1,091     |
| Asset retirement obligation costs                 | 36       | 6                                     | 42        |
| Total costs incurred                              | \$ 891   | \$ 242                                | \$ 1,133  |
| <i>2009 Unconsolidated Affiliate Four States:</i> |          |                                       |           |
| Development costs expended                        | \$ 10    | \$                                    | \$ 10     |
| <i>2008 Consolidated:</i>                         |          |                                       |           |
| Property acquisition costs                        |          |                                       |           |
| Proved properties                                 | \$ 51    | \$                                    | \$ 51     |
| Unproved properties                               | 74       | 1                                     | 75        |
| Exploration costs                                 | 438      | 104                                   | 542       |
| Development costs                                 | 938      | 93                                    | 1,031     |
| Costs expended                                    | 1,501    | 198                                   | 1,699     |
| Asset retirement obligation costs                 | 19       |                                       | 19        |

|                      |          |        |          |
|----------------------|----------|--------|----------|
| Total costs incurred | \$ 1,520 | \$ 198 | \$ 1,718 |
|----------------------|----------|--------|----------|

(1) Costs incurred for Egypt were \$20 million, \$81 million and \$26 million for the years ended December 31, 2010, 2009 and 2008.

(2) Amounts represent our approximate 49 percent equity interest in the underlying costs incurred by Four Star.

Pursuant to the full cost method of accounting, we capitalize certain general and administrative expenses directly related to property acquisition, exploration and development activities and interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. The table above includes capitalized internal general and administrative costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of \$81 million, \$80 million and \$85 million for the years ended December 31, 2010, 2009 and 2008. We also capitalized interest of \$9 million, \$7 million and \$29 million for the years ended December 31, 2010, 2009 and 2008.

In our December 31, 2010 reserve report, the amounts estimated to be spent in 2011, 2012 and 2013 to develop our consolidated worldwide proved undeveloped reserves are \$597 million, \$616 million and \$512 million.

**Table of Contents**

*Unevaluated Capitalized Costs.* We exclude capitalized costs of natural gas and oil properties from amortization that are in various stages of evaluation or are part of a major development project. We expect these costs to be included in the amortization calculation in the next three to five years.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2010 pending determination of proved reserves (in millions):

|                                     | Cumulative<br>Balance<br>December<br>31,<br>2010 | Costs Excluded<br>for Years Ended |                            |       | Cumulative<br>Balance<br>January 1,<br>2008 |
|-------------------------------------|--|-----------------------------------|----------------------------|-------|---|
|                                     |  | 2010                              | December 31 <sup>(1)</sup> |       |   |
|                                     |  | 2009                              | 2008                       |       |   |
| <i>U.S.</i>                         |  |                                   |                            |       |   |
| Acquisition                         | \$ 407   | \$ 257                            | \$ 72                      | \$ 43 | \$ 35                                       |
| Exploration                         | 130  | 109                               | 15                         | 5     | 1   |
| Total U.S.                          | 537  | 366                               | 87                         | 48    | 36  |
| <i>Brazil &amp; Egypt</i>           |  |                                   |                            |       |   |
| Acquisition                         | 45   | 5                                 | 35                         | 1     | 4   |
| Exploration                         | 203  | 52                                | 22                         | 31    | 98  |
| Total Brazil & Egypt <sup>(2)</sup> | 248  | 57                                | 57                         | 32    | 102   |
| Worldwide                           | \$ 785   | \$ 423                            | \$ 144                     | \$ 80 | \$ 138                                      |

(1) Includes capitalized interest of \$8 million, \$5 million and \$4 million for the years ended December 31, 2010, 2009 and 2008.

(2) Includes \$66 million related to Egypt at December 31, 2010.

Our unevaluated costs in Brazil include approximately \$94 million related to our major development project in the Pinauna field. These costs relate to exploratory drilling in 2007 which led to a discovery of hydrocarbons that will be used as fuel in the development of the Pinauna project. We are currently working to obtain environmental permits to develop the project and have experienced delays in obtaining these permits due to a number of factors, including changes in government and additional regulatory inquiries resulting indirectly from the Gulf of Mexico spill in 2010. We currently anticipate we will receive a decision on our preliminary license request during late 2011 allowing us to proceed with development activities. Additionally, we expect to begin including unevaluated Pinauna project costs in the amortizable base in 2014 as the project is evaluated. However, we could experience additional delays of our development activities. Prior to the completion of our evaluation, we expect that our unevaluated Pinauna project costs will continue to be held outside of the amortizable base of the Brazilian full cost pool. All of our unevaluated costs, including those related to the Pinauna project, are assessed periodically for impairment.

*Natural Gas and Oil Reserves.* Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil and condensate, and changes in these reserves at December 31, 2010 presented in the tables below are based on our internal reserve report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate. Our 2009 consolidated proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2010 except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), conducted an audit of the estimates of the proved reserves prepared by us as of December 31, 2010. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our proved reserves on a natural gas equivalent basis, representing 88 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, 2010. In connection with the audit of these proved reserves, Ryder Scott reviewed 86 percent of the properties associated with Four Star's total proved reserves on a natural gas equivalent basis, representing 86 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.

**Table of Contents**

|   | Natural Gas (in Bcf) |        |           | Oil and Condensate<br>(in MBbls) |          |           | NGL<br>(in<br>MBbls) | Equivalent<br>Volumes<br>(in Bcfe) |
|---|----------------------|--------|-----------|----------------------------------|----------|-----------|----------------------|------------------------------------|
|   | U.S.                 | Brazil | Worldwide | U.S.                             | Brazil   | Worldwide | U.S.                 |                                    |
| <i>Consolidated:</i>                          |                      |        |           |                                  |          |           |                      |                                    |
| January 1, 2008                               | 2,248                | 51     | 2,299     | 49,674                           | 32,710   | 82,384    | 10,114               | 2,853                              |
| Revisions due to prices                       | (136)                | (1)    | (137)     | (26,018)                         | (29,406) | (55,424)  | (985)                | (476)                              |
| Revisions other than price                    | (52)                 |        | (52)      | (2,546)                          |          | (2,546)   | (891)                | (72)                               |
| Extensions and discoveries <sup>(1)</sup>     | 475                  |        | 475       | 16,468                           |          | 16,468    | 456                  | 577                                |
| Purchases of reserves in place <sup>(1)</sup> | 10                   |        | 10        | 1,295                            |          | 1,295     | 68                   | 18                                 |
| Sales of reserves in place <sup>(1)</sup>     | (224)                |        | (224)     | (10,440)                         |          | (10,440)  | (2,754)              | (303)                              |
| Production                                    | (230)                | (3)    | (233)     | (4,523)                          | (124)    | (4,647)   | (1,849)              | (272)                              |
| December 31, 2008                             | 2,091                | 47     | 2,138     | 23,910                           | 3,180    | 27,090    | 4,159                | 2,325                              |
| Revisions due to prices                       | (138)                | (2)    | (140)     | 13,336                           | (380)    | 12,956    | (3,552)              | (84)                               |
| Revisions other than price                    | (36)                 | (6)    | (42)      | 3,477                            | (640)    | 2,837     | 1,511                | (16)                               |
| Extensions and discoveries <sup>(2)</sup>     | 380                  | 70     | 450       | 18,089                           | 2,136    | 20,225    | 16                   | 572                                |
| Purchases of reserves in place <sup>(2)</sup> | 19                   |        | 19        | 7,343                            |          | 7,343     |                      | 63                                 |
| Sales of reserves in place <sup>(2)</sup>     | (49)                 |        | (49)      | (1,328)                          |          | (1,328)   | (260)                | (59)                               |
| Production                                    | (215)                | (4)    | (219)     | (3,978)                          | (100)    | (4,078)   | (1,570)              | (252)                              |
| December 31, 2009                             | 2,052                | 105    | 2,157     | 60,849                           | 4,196    | 65,045    | 304                  | 2,549                              |
| Revisions due to prices                       | 108                  | 3      | 111       | 8,719                            | 88       | 8,807     | 105                  | 164                                |
| Revisions other than price                    | (58)                 | (13)   | (71)      | 7,873                            | (1,246)  | 6,627     | 6,977                | 11                                 |
| Extensions and discoveries <sup>(3)</sup>     | 506                  |        | 506       | 28,141                           |          | 28,141    | 3,088                | 693                                |
| Purchases of reserves in place <sup>(3)</sup> | 25                   |        | 25        | 3,045                            |          | 3,045     |                      | 43                                 |
| Sales of reserves in place <sup>(3)</sup>     | (21)                 |        | (21)      | (1,024)                          |          | (1,024)   |                      | (27)                               |
| Production                                    | (216)                | (10)   | (226)     | (4,363)                          | (384)    | (4,747)   | (1,423)              | (263)                              |

Edgar Filing: EL PASO CORP/DE - Form 10-K

|                      |       |    |       |         |       |         |       |       |
|----------------------|-------|----|-------|---------|-------|---------|-------|-------|
| December 31,<br>2010 | 2,396 | 85 | 2,481 | 103,240 | 2,654 | 105,894 | 9,051 | 3,170 |
|                      |       |    |       | 154     |       |         |       |       |

---

**Table of Contents**

|  | Natural Gas (in Bcf) |        |           | Oil and Condensate<br>(in MBbls) |        |           | NGL<br>(in<br>MBbls) | Equivalent<br>Volumes<br>(in Bcfe) |
|--|----------------------|--------|-----------|----------------------------------|--------|-----------|----------------------|------------------------------------|
|  | U.S.                 | Brazil | Worldwide | U.S.                             | Brazil | Worldwide | U.S.                 |                                    |
| <i>Unconsolidated</i>                  |                      |        |           |                                  |        |           |                      |                                    |
| <i>Affiliate Four Std<sup>2</sup>:</i> |                      |        |           |                                  |        |           |                      |                                    |
| January 1, 2009                        | 176                  |        | 176       | 2,199                            |        | 2,199     | 5,518                | 222                                |
| Revisions due to prices                | (9)                  |        | (9)       | 23                               |        | 23        | (40)                 | (9)                                |
| Revisions other than price             | 10                   |        | 10        | 100                              |        | 100       | 456                  | 13                                 |
| Extensions and discoveries             | 1                    |        | 1         | 4                                |        | 4         | 8                    | 1                                  |
| Production                             | (20)                 |        | (20)      | (419)                            |        | (419)     | (678)                | (26)                               |
| December 31, 2009                      | 158                  |        | 158       | 1,907                            |        | 1,907     | 5,264                | 201                                |
| Revisions due to prices                | 8                    |        | 8         | 44                               |        | 44        | 87                   | 9                                  |
| Revisions other than price             | 6                    |        | 6         | 36                               |        | 36        | (325)                | 4                                  |
| Extensions and discoveries             |                      |        |           |                                  |        |           | 5                    |                                    |
| Production                             | (17)                 |        | (17)      | (364)                            |        | (364)     | (573)                | (22)                               |
| December 31, 2010                      | 155                  |        | 155       | 1,623                            |        | 1,623     | 4,458                | 192                                |
| <i>Total Combined:</i>                 |                      |        |           |                                  |        |           |                      |                                    |
| December 31, 2009                      | 2,210                | 105    | 2,315     | 62,756                           | 4,196  | 66,952    | 5,568                | 2,750                              |
| December 31, 2010                      | 2,551                | 85     | 2,636     | 104,863                          | 2,654  | 107,517   | 13,509               | 3,362                              |
| <i>Consolidated:</i>                   |                      |        |           |                                  |        |           |                      |                                    |
| Proved developed reserves:             |                      |        |           |                                  |        |           |                      |                                    |
| Beginning of year                      | 1,441                | 91     | 1,532     | 26,588                           | 3,212  | 29,800    | 304                  | 1,713                              |
| End of year                            | 1,559                | 75     | 1,634     | 38,278                           | 2,403  | 40,681    | 6,096                | 1,914                              |
| Proved undeveloped reserves:           |                      |        |           |                                  |        |           |                      |                                    |
| Beginning of year                      | 610                  | 14     | 624       | 34,261                           | 984    | 35,245    |                      | 836                                |
| End of year                            | 837                  | 10     | 847       | 64,962                           | 251    | 65,213    | 2,955                | 1,256                              |

**Table of Contents**

|                              | Natural Gas (in Bcf) |        |           | Oil and Condensate<br>(in MBbls) |        |           | NGL<br>(in<br>MBbls) | Equivalent<br>Volumes<br>(in<br>Bcfe) |
|------------------------------|----------------------|--------|-----------|----------------------------------|--------|-----------|----------------------|---------------------------------------|
|                              | U.S.                 | Brazil | Worldwide | U.S.                             | Brazil | Worldwide | U.S.                 |                                       |
|                              |                      |        |           |                                  |        |           |                      |                                       |
| <i>Unconsolidated</i>        |                      |        |           |                                  |        |           |                      |                                       |
| <i>Affiliate Four</i>        |                      |        |           |                                  |        |           |                      |                                       |
| <i>Star:</i>                 |                      |        |           |                                  |        |           |                      |                                       |
| Proved developed reserves:   |                      |        |           |                                  |        |           |                      |                                       |
| Beginning of year            | 135                  |        | 135       | 1,860                            |        | 1,860     | 4,295                | 172                                   |
| End of year                  | 129                  |        | 129       | 1,574                            |        | 1,574     | 3,483                | 159                                   |
| Proved undeveloped reserves: |                      |        |           |                                  |        |           |                      |                                       |
| Beginning of year            | 23                   |        | 23        | 47                               |        | 47        | 969                  | 29                                    |
| End of year                  | 26                   |        | 26        | 49                               |        | 49        | 975                  | 32                                    |
| <i>Total Combined:</i>       |                      |        |           |                                  |        |           |                      |                                       |
| Proved developed reserves:   |                      |        |           |                                  |        |           |                      |                                       |
| Beginning of year            | 1,577                | 91     | 1,668     | 28,448                           | 3,212  | 31,660    | 4,599                | 1,885                                 |
| End of year                  | 1,688                | 75     | 1,763     | 39,852                           | 2,403  | 42,255    | 9,579                | 2,074                                 |
| Proved undeveloped reserves: |                      |        |           |                                  |        |           |                      |                                       |
| Beginning of year            | 633                  | 14     | 647       | 34,308                           | 984    | 35,292    | 969                  | 865                                   |
| End of year                  | 863                  | 10     | 873       | 65,011                           | 251    | 65,262    | 3,930                | 1,288                                 |

- (1) In 2008, of the 577 Bcfe of extensions and discoveries, 201 Bcfe related to the Raton area in northern New Mexico and 132 Bcfe related to the Rockies. However, approximately 130 Bcfe of the 132 Bcfe related to the Rockies was also recorded as a pricing revision due to unfavorable commodity prices at December 31, 2008. We also had 99 Bcfe of extensions and discoveries related to the Arklatex area, 38 Bcfe related to the McCook area and 31 Bcfe related to the Zapata area, both in the south Texas area and 22 Bcfe related to High Island in the Gulf of Mexico. In 2008, we acquired interests in domestic natural gas and oil producing properties located in the Western and Central divisions. We also sold domestic natural gas and oil properties located primarily in the Gulf of Mexico.
- (2) In 2009, of the 572 Bcfe of extensions and discoveries, 301 Bcfe related to the Central division, of which, 208 Bcfe related to the Haynesville Shale and 70 Bcfe related to the Holly/Kingston fields. We also had 147 Bcfe of extensions and discoveries related to Altamont in the Western division and 83 Bcfe related to the Camarupim Field in Brazil. In addition, 41 Bcfe of extensions and discoveries related to the Gulf Coast division, of which, 14 Bcfe related to Eugene Island 364/365 in the Gulf of Mexico and 12 Bcfe related to the Wilcox area in South Texas. In 2009, we acquired interests in domestic natural gas and oil producing properties located in the Western division. We also sold domestic natural gas producing properties located in the Central and Western divisions.
- (3) In 2010, of the 693 Bcfe of extensions and discoveries, 452 Bcfe related to the Central division, of which, 425 Bcfe related to the Haynesville Shale area. There were 238 Bcfe of extensions and discoveries in the Gulf Coast division with 187 Bcfe of that coming from the Eagle Ford Shale. The Western division accounted for 3 Bcfe of

extensions and discoveries and there were no extensions and discoveries in the International division.

In January 2010, the Financial Accounting Standards Board updated accounting standards on extractive activities for oil and gas to align the oil and gas reserve estimation and disclosures with the requirements in the SEC's final rule on Modernization of Oil and Gas Reserve Reporting, which was effective December 31, 2009. Among other things, the new standard revised the definition of proved reserves and required us to use a 12-month average price to estimate proved reserves rather than a period end spot price as required in prior periods. The 12-month average price is calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The first day 12-month average U.S. price used to estimate our proved reserves at December 31, 2010 was \$4.38 per MMBtu for natural gas and \$79.43 per barrel of oil.

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of reasonable certainty be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices, economic conditions and government restrictions. In addition, as a result of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate.

**Table of Contents**

Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon economic factors, such as natural gas and oil prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Subsequent to December 31, 2010, there have been no major discoveries or other events, favorable or otherwise, that may be considered to have caused a significant change in our estimated proved reserves.

**Table of Contents**

*Results of Operations.* Results of operations for natural gas and oil producing activities by fiscal year were as follows at December 31 (in millions):

|  | U.S.    | Brazil<br>and<br>Egypt | Worldwide |
|--|---------|------------------------|-----------|
| <i>2010 Consolidated:</i>  |         |                        |           |
| Net Revenues <sup>(1)</sup>                                      |         |                        |           |
| Sales to external customers                                      | \$ 551  | \$ 86                  | \$ 637    |
| Affiliated sales   | 743     |                        | 743       |
| Total  | 1,294   | 86                     | 1,380     |
| Cost of products and services <sup>(2)</sup>                     | (81)    | (5)                    | (86)      |
| Production costs <sup>(3)</sup>                                  | (218)   | (46)                   | (264)     |
| Ceiling test charges <sup>(4)</sup>                              |         | (25)                   | (25)      |
| Depreciation, depletion and amortization                         | (432)   | (28)                   | (460)     |
|  | 563     | (18)                   | 545       |
| Income tax expense   | (204)   |                        | (204)     |
| Results of operations from producing activities                  | \$ 359  | \$ (18)                | \$ 341    |
| Depreciation, depletion and amortization (\$/Mcf) <sup>(5)</sup> | \$ 1.72 | \$ 2.33                | \$ 1.75   |
| <i>2010 Unconsolidated Affiliate - Four States:</i>              |         |                        |           |
| Net Revenues - Sales to external customers <sup>(4)</sup>        | \$ 119  | \$                     | \$ 119    |
| Cost of products and services                                    | (4)     |                        | (4)       |
| Production costs <sup>(3)</sup>                                  | (36)    |                        | (36)      |
| Depreciation, depletion and amortization                         | (28)    |                        | (28)      |
| Asset impairment   | (4)     |                        | (4)       |
|  | 47      |                        | 47        |
| Income tax expense   | (17)    |                        | (17)      |
| Results of operations from producing activities                  | \$ 30   | \$                     | \$ 30     |
| Depreciation, depletion and amortization (\$/Mcf) <sup>(7)</sup> | \$ 1.24 | \$                     | \$ 1.24   |
| <i>2009 Consolidated:</i>  |         |                        |           |
| Net Revenues <sup>(1)</sup>                                      |         |                        |           |
| Sales to external customers                                      | \$ 534  | \$ 25                  | \$ 559    |
| Affiliated sales   | 538     |                        | 538       |
| Total  | 1,072   | 25                     | 1,097     |
| Cost of products and services <sup>(2)</sup>                     | (72)    | (5)                    | (77)      |
| Production costs <sup>(3)</sup>                                  | (226)   | (26)                   | (252)     |
| Table of Contents  |         |                        | 236       |

Edgar Filing: EL PASO CORP/DE - Form 10-K

|   |            |          |            |
|---|------------|----------|------------|
| Ceiling test charges <sup>(4)</sup>                               | (2,031)    | (92)     | (2,123)    |
| Depreciation, depletion and amortization                          | (415)      | (9)      | (424)      |
|   | (1,672)    | (107)    | (1,779)    |
| Income tax benefit  | 605        |          | 605        |
| Results of operations from producing activities                   | \$ (1,067) | \$ (107) | \$ (1,174) |
| Depreciation, depletion and amortization (\$/Mcfe) <sup>(5)</sup> | \$ 1.67    | \$ 2.13  | \$ 1.68    |
| <i>2009 Unconsolidated Affiliate Four States:</i>                 |            |          |            |
| Net Revenues Sales to external customers <sup>(4)</sup>           | \$ 100     | \$       | \$ 100     |
| Cost of products and services <sup>(2)</sup>                      | (6)        |          | (6)        |
| Production costs <sup>(3)</sup>                                   | (37)       |          | (37)       |
| Depreciation, depletion and amortization                          | (29)       |          | (29)       |
|   | 28         |          | 28         |
| Income tax expense  | (10)       |          | (10)       |
| Results of operations from producing activities                   | \$ 18      | \$       | \$ 18      |
| Depreciation, depletion and amortization (\$/Mcfe) <sup>(7)</sup> | \$ 1.09    | \$       | \$ 1.09    |

**Table of Contents**

|  | <b>U.S.</b>     | <b>Brazil<br/>and<br/>Egypt</b> | <b>Worldwide</b>  |
|--|-----------------|---------------------------------|-------------------|
| <i>2008 Consolidated:</i>  |                 |                                 |                   |
| Net Revenues <sup>(1)</sup>  |                 |                                 |                   |
| Sales to external customers  | \$ 951          | \$ 20                           | \$ 971            |
| Affiliated sales   | 1,421           |                                 | 1,421             |
| <b>Total</b>   | <b>2,372</b>    | <b>20</b>                       | <b>2,392</b>      |
| Cost of products and services <sup>(2)</sup>                           | (79)            |                                 | (79)              |
| Production costs <sup>(3)</sup>  | (354)           | (9)                             | (363)             |
| Ceiling test charges <sup>(4)</sup>                                    | (2,181)         | (488)                           | (2,669)           |
| Depreciation, depletion and amortization                               | (768)           | (14)                            | (782)             |
|  | (1,010)         | (491)                           | (1,501)           |
| Income tax expense (benefit) <sup>(8)</sup>                            | 364             |                                 | 364               |
| <b>Results of operations from producing activities</b>                 | <b>\$ (646)</b> | <b>\$ (491)</b>                 | <b>\$ (1,137)</b> |
| <b>Depreciation, depletion and amortization (\$/Mcf)<sup>(5)</sup></b> | <b>\$ 2.87</b>  | <b>\$ 3.62</b>                  | <b>\$ 2.88</b>    |

(1) Excludes the effects of natural gas and oil derivative contracts.

(2) Cost of products and services consists of transportation costs and divisional general and administrative expenses of \$13 million and \$11 million in 2010 and 2009 and only transportation costs in 2008.

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

(4) Includes \$25 million, \$34 million and \$9 million related to Egypt for the years ended December 31, 2010, 2009 and 2008.

(5) These amounts represent depreciation, depletion and amortization for unit of production only and include accretion expense on asset retirement obligations of \$0.06/Mcfe in 2010 and 2009, respectively, and \$0.05/Mcfe in 2008.

(6) Results do not include amortization of \$38 million related to cost in excess of our equity interest in the underlying net assets of Four Star.

(7) Includes accretion expense on asset retirement obligations of \$0.14/Mcfe in 2010 and \$0.13/Mcfe in 2009.

(8) See Note 5 for a description of the deferred tax valuation allowance recorded in 2008 associated with our Brazil net operating losses and ceiling test charge.

**Table of Contents**

*Standardized Measure of Discounted Future Net Cash Flows.* The standardized measure of discounted future net cash flows relating to our consolidated proved natural gas and oil reserves at December 31 is as follows (in millions):

|  | <b>U.S.</b> | <b>Brazil</b> | <b>Worldwide</b> |
|--|-------------|---------------|------------------|
| <i>2010 Consolidated:</i>                                |             |               |                  |
| Future cash inflows <sup>(1)</sup>                       | \$ 17,145   | \$ 659        | \$ 17,804        |
| Future production costs                                  | (4,768)     | (325)         | (5,093)          |
| Future development costs                                 | (3,249)     | (67)          | (3,316)          |
| Future income tax expenses                               | (2,403)     | (9)           | (2,412)          |
| Future net cash flows                                    | 6,725       | 258           | 6,983            |
| 10% annual discount for estimated timing of cash flows   | (2,905)     | (77)          | (2,982)          |
| Standardized measure of discounted future net cash flows | \$ 3,820    | \$ 181        | \$ 4,001         |
| <i>2010 Unconsolidated Affiliate Four States:</i>        |             |               |                  |
| Future cash inflows <sup>(1)</sup>                       | \$ 943      | \$            | \$ 943           |
| Future production costs                                  | (404)       |               | (404)            |
| Future development costs                                 | (34)        |               | (34)             |
| Future income tax expenses                               | (192)       |               | (192)            |
| Future net cash flows                                    | 313         |               | 313              |
| 10% annual discount for estimated timing of cash flows   | (131)       |               | (131)            |
| Standardized measure of discounted future net cash flows | \$ 182      | \$            | \$ 182           |
| <i>2009 Consolidated:</i>                                |             |               |                  |
| Future cash inflows <sup>(1)</sup>                       | \$ 10,058   | \$ 714        | \$ 10,772        |
| Future production costs                                  | (3,531)     | (339)         | (3,870)          |
| Future development costs                                 | (1,698)     | (108)         | (1,806)          |
| Future income tax expenses                               | (511)       | (17)          | (528)            |
| Future net cash flows                                    | 4,318       | 250           | 4,568            |
| 10% annual discount for estimated timing of cash flows   | (1,744)     | (82)          | (1,826)          |
| Standardized measure of discounted future net cash flows | \$ 2,574    | \$ 168        | \$ 2,742         |
| <i>2009 Unconsolidated Affiliate Four States:</i>        |             |               |                  |
| Future cash inflows <sup>(1)</sup>                       | \$ 855      | \$            | \$ 855           |
| Future production costs                                  | (394)       |               | (394)            |
| Future development costs                                 | (32)        |               | (32)             |
| Future income tax expenses                               | (157)       |               | (157)            |
| Future net cash flows                                    | 272         |               | 272              |
| 10% annual discount for estimated timing of cash flows   | (110)       |               | (110)            |

Edgar Filing: EL PASO CORP/DE - Form 10-K

|  |           |        |           |
|--|-----------|--------|-----------|
| Standardized measure of discounted future net cash flows     | \$ 162    | \$     | \$ 162    |
| <i>2008 Consolidated:</i>                                    |           |        |           |
| Future cash inflows <sup>(1)</sup>                           | \$ 11,667 | \$ 242 | \$ 11,909 |
| Future production costs                                      | (3,495)   | (45)   | (3,540)   |
| Future development costs                                     | (1,406)   | (65)   | (1,471)   |
| Future income tax expenses                                   | (1,152)   | (20)   | (1,172)   |
| Future net cash flows  | 5,614     | 112    | 5,726     |
| 10% annual discount for estimated timing of cash flows       | (2,274)   | (56)   | (2,330)   |
| Standardized measure of discounted future net cash flows     | \$ 3,340  | \$ 56  | \$ 3,396  |
| <i>2008 Unconsolidated Affiliate Four Star<sup>(2)</sup></i> | \$ 396    | \$     | \$ 396    |

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2010, 2009 and 2008. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves as of December 31, 2010 were computed using a first day 12-month average U.S. price of \$4.38 per MMBtu for natural gas and \$79.43 per barrel of oil. The 12-month average price is calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period.

**Table of Contents**

*Changes in Standardized Measure of Discounted Future Net Cash Flows.* The following are the principal sources of change in our consolidated worldwide standardized measure of discounted future net cash flows (in millions):

|   | <b>Years Ended December 31,<sup>(1)</sup></b> |             |             |
|---|---|-------------|-------------|
|   | <b>2010</b>                                   | <b>2009</b> | <b>2008</b> |
|   | <b>(In millions)</b>                          |             |             |
| <i>Consolidated:</i>  |   |             |             |
| Sales and transfers of natural gas and oil produced net of production costs | \$ (1,042)                                    | \$ (779)    | \$ (2,059)  |
| Net changes in prices and production costs                                  | 1,734   | (1,455)     | (3,380)     |
| Extensions, discoveries and improved recovery, less related costs           | 986   | 646         | 1,136       |
| Changes in estimated future development costs                               | (226)   | 45          | 342         |
| Previously estimated development costs incurred during the period           | 199   | 186         | 141         |
| Revision of previous quantity estimates                                     | 315   | (94)        | (887)       |
| Accretion of discount   | 220   | 310         | 622         |
| Net change in income taxes  | (934)   | 246         | 1,458       |
| Purchases of reserves in place  | 73  | 121         | 36          |
| Sales of reserves in place  | (47)  | (79)        | (603)       |
| Change in production rates, timing and other                                | (19)  | 199         | (244)       |
| Net change  | \$ 1,259                                      | \$ (654)    | \$ (3,438)  |
| <i>Unconsolidated Affiliate Four Star:</i>                                  |   |             |             |
| Sales and transfers of natural gas and oil produced net of production costs | \$ (83)                                       | \$ (137)    |             |
| Net changes in prices and production costs                                  | 70  | (351)       |             |
| Extensions, discoveries and improved recovery, less related costs           | 1   | 1           |             |
| Changes in estimated future development costs                               | (1)   | 22          |             |
| Revision of previous quantity estimates                                     | 16  | 5           |             |
| Accretion of discount   | 18  | 57          |             |
| Net change in income taxes  | (16)  | 137         |             |
| Change in production rates, timing and other                                | 15  | 32          |             |
| Net change  | \$ 20   | \$ (234)    |             |

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

**Table of Contents**

Schedule

**SCHEDULE II**  
**EL PASO CORPORATION**  
**VALUATION AND QUALIFYING ACCOUNTS**  
**Years Ended December 31, 2010, 2009 and 2008**  
**(In millions)**

| Description                                | Balance<br>at<br>Beginning<br>of Period | Charged<br>to<br>Costs and<br>Expenses | Deductions | Charged<br>to Other<br>Accounts | Balance<br>at<br>End of<br>Period |
|--|---|--|------------|---------------------------------|-----------------------------------|
| 2010                                       |   |  |            |                                 |                                   |
| Allowance for doubtful accounts            | \$ 8                                    | \$                                     | \$         | \$ (4)                          | \$ 4                              |
| Valuation allowance on deferred tax assets | 384                                     | 7 <sup>(2)</sup>                       |            |                                 | 391                               |
| Legal reserves <sup>(1)</sup>              | 66                                      | 14                                     | (34)       | (1)                             | 45                                |
| Environmental reserves                     | 189                                     | 26                                     | (42)       |                                 | 173                               |
| Regulatory reserves <sup>(3)</sup>         | 74                                      | 21                                     | (76)       |                                 | 19                                |
| 2009                                       |   |  |            |                                 |                                   |
| Allowance for doubtful accounts            | \$ 9                                    | \$                                     | \$         | \$ (1)                          | \$ 8                              |
| Valuation allowance on deferred tax assets | 337                                     | 47 <sup>(6)</sup>                      |            |                                 | 384                               |
| Legal reserves <sup>(1)</sup>              | 73                                      | 20                                     | (27)       |                                 | 66                                |
| Environmental reserves                     | 204                                     | 25                                     | (40)       |                                 | 189                               |
| Regulatory reserves <sup>(3)</sup>         |   | 74                                     |            |                                 | 74                                |
| 2008                                       |   |  |            |                                 |                                   |
| Allowance for doubtful accounts            | \$ 17                                   | \$ (2)                                 | \$         | \$ (6)                          | \$ 9                              |
| Valuation allowance on deferred tax assets | 137                                     | 202 <sup>(4)</sup>                     |            | (2)                             | 337                               |
| Legal reserves <sup>(1)</sup>              | 460                                     | (91)                                   | (16)       | (280) <sup>(5)</sup>            | 73                                |
| Environmental reserves                     | 260                                     | (11)                                   | (44)       | (1)                             | 204                               |
| Regulatory reserves <sup>(3)</sup>         | 10                                      |  | (10)       |                                 |                                   |

(1) Amounts are net of related insurance receivables.

(2) Amounts reflect valuation allowances primarily associated with Brazil and Egypt net operating losses and the reversal of valuation allowances for federal and state net operating losses and state deferred tax assets.

(3) Reflects rate refund and settlement activity.

(4) Amounts reflect valuation allowances associated with Brazil net operating losses and ceiling test charges.

(5) Amount reclassified as postretirement liability.

(6) Amounts reflect valuation allowances primarily associated with Brazil net operating losses and ceiling test charges and the reversal of valuation allowances for state net operating losses and deferred tax assets.

**Table of Contents**

**ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

None.

**ITEM 9A. CONTROLS AND PROCEDURES**

**Evaluation of Disclosure Controls and Procedures**

As of December 31, 2010, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2010. See Item 8, Financial Statements and Supplementary Data under Management's Annual Report on Internal Control Over Financial Reporting.

**Changes in Internal Control over Financial Reporting**

There were no changes in our internal control over financial reporting during the fourth quarter of 2010 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

**ITEM 9B. OTHER INFORMATION**

None.

**Table of Contents**

**PART III**

**ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**

The information included under the captions Corporate Governance , Proposal No. 1 Election of Directors , Section 16(a) Beneficial Ownership Reporting Compliance and Information about the Board of Directors and Committees in our Proxy Statement for the 2011 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption Executive Officers of the Registrant.

**ITEM 11. EXECUTIVE COMPENSATION**

Information appearing under the captions Information about the Board of Directors and Committees Compensation Committee Interlocks and Insider Participation , Compensation Discussion and Analysis , Compensation Committee Report , Executive Compensation and Director Compensation in our Proxy Statement for the 2011 Annual Meeting of Stockholders is incorporated herein by reference.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

Information appearing under the captions Security Ownership of a Certain Beneficial Owner and Management and Equity Compensation Plan Information Table in our Proxy Statement for the 2011 Annual Meeting of Stockholders is incorporated herein by reference.

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

Information appearing under the captions Corporate Governance Independence of Board Members and Corporate Governance Transactions with Related Persons in our Proxy Statement for the 2011 Annual Meeting of Stockholders is incorporated herein by reference.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

Information appearing under the caption Proposal No. 4 Ratification of the Appointment of Ernst & Young LLP as our Independent Registered Public Accounting Firm Principal Accountant Fees and Services and Information about the Board of Directors and Committees Policy for Approval of Audit and Non-Audit Fees in our Proxy Statement for the 2011 Annual Meeting of Stockholders is incorporated herein by reference.

**Table of Contents****PART IV****ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES****(a) The following documents are filed as a part of this report:**

## 1. Financial statements.

The following consolidated financial statements are included in Part II, Item 8 of this report:

|   | <b>Page</b> |
|---|-------------|
| Reports of Independent Registered Public Accounting Firms   | 94          |
| Consolidated Statements of Income   | 98          |
| Consolidated Balance Sheets   | 99          |
| Consolidated Statements of Cash Flows   | 101         |
| Consolidated Statements of Equity   | 102         |
| Consolidated Statements of Comprehensive Income   | 103         |
| Notes to Consolidated Financial Statements  | 104         |
| 2. Financial statement schedules and supplementary information required to be submitted Schedule II |             |
| Valuation and Qualifying Accounts   | 162         |
| 3. Exhibits   | 167         |

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

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:

should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;

may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;

may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and

were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

**Undertaking**

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4) (iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

**Table of Contents****SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 28th day of February 2011.

**EL PASO CORPORATION**

By: /s/ Douglas L. Foshee  
Douglas L. Foshee  
*President and Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of El Paso Corporation and in the capacities and on the dates indicated:

| <b>Signature</b>           | <b>Title</b>  | <b>Date</b>       |
|----------------------------|---|-------------------|
| /s/ Douglas L. Foshee      | President, Chief Executive Officer                              | February 28, 2011 |
| Douglas L. Foshee          | and<br>Chairman of the Board<br>(Principal Executive Officer)   |                   |
| /s/ John R. Sult           | Executive Vice President and Chief<br>Financial<br>Officer      | February 28, 2011 |
| John R. Sult               | (Principal Financial Officer)                                   |                   |
| /s/ Francis C. Olmsted III | Vice President and Controller<br>(Principal Accounting Officer) | February 28, 2011 |
| Francis C. Olmsted III     |   |                   |
| /s/ Juan Carlos Braniff    | Director  | February 28, 2011 |
| Juan Carlos Braniff        |   |                   |
| /s/ David W. Crane         | Director  | February 28, 2011 |
| David W. Crane             |   |                   |
| /s/ Robert W. Goldman      | Director  | February 28, 2011 |
| Robert W. Goldman          |   |                   |
| /s/ Anthony W. Hall, Jr.   | Director  | February 28, 2011 |
| Anthony W. Hall, Jr.       |   |                   |
| /s/ Thomas R. Hix          | Director  | February 28, 2011 |
| Thomas R. Hix              |   |                   |

|                        |          |                   |
|------------------------|----------|-------------------|
| /s/ Ferrell P. McClean | Director | February 28, 2011 |
| Ferrell P. McClean     |          |                   |
| /s/ Timothy J. Probert | Director | February 28, 2011 |
| Timothy J. Probert     |          |                   |
| /s/ Steven J. Shapiro  | Director | February 28, 2011 |
| Steven J. Shapiro      |          |                   |
| /s/ J. Michael Talbert | Director | February 28, 2011 |
| J. Michael Talbert     |          |                   |
| /s/ Robert F. Vagt     | Director | February 28, 2011 |
| Robert F. Vagt         |          |                   |
| /s/ John L. Whitmire   | Director | February 28, 2011 |
| John L. Whitmire       |          |                   |

**Table of Contents**

**EL PASO CORPORATION  
EXHIBIT INDEX  
December 31, 2010**

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by \*. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement.

| <b>Exhibit<br/>Number</b> | <b>Description</b>  |
|---------------------------|---|
| *3.A                      | Second Amended and Restated Certificate of Incorporation.   |
| 3.B                       | By-laws effective as of May 6, 2009 (Exhibit 3.B to our Current Report on Form 8-K filed with the SEC on May 6, 2009).  |
| *4.A                      | Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee.   |
| *4.B                      | Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock.   |
| 4.C                       | Tenth Supplemental Indenture dated as of December 28, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on January 4, 2006).  |
| 4.D                       | Eleventh Supplemental Indenture dated as of August 31, 2006, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006). |
| 4.E                       | Twelfth Supplemental Indenture dated as of June 18, 2007 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Quarterly Report on Form 10-Q for the period ended June 30, 2007, filed with the SEC on August 7, 2007).            |
| 4.F                       | Thirteenth Supplemental Indenture dated as of May 30, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4 to our Quarterly Report on Form 10-Q for the period ended June 30, 2008, filed with the SEC on August 8, 2008).            |
| 4.G                       | Fourteenth Supplemental Indenture dated as of December 12, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.H to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).       |
| 4.H                       | Fifteenth Supplemental Indenture, dated as of February 9, 2009 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.I to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).        |
| 4.I                       |   |

Sixteenth Supplemental Indenture, dated as of September 24, 2010, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).

- +10.A 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of January 1, 2007 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of January 1, 2008 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003(Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).

**Table of Contents**

| <b>Exhibit<br/>Number</b> | <b>Description</b>  |
|---------------------------|---|
| *+10.B                    | Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999.   |
| *+10.B.1                  | Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors.  |
| +10.B.2                   | Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.B.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).  |
| +10.B.3                   | Amendment No. 3 effective as of October 26, 2006 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.N to our Quarterly Report on Form 10-Q for the period ended on September 30, 2006, filed with the SEC on November 6, 2006).  |
| +10.C                     | 2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001(Exhibit 10.C to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of October 26, 2006 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.O to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).  |
| +10.D                     | 2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.F. to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan. (Exhibit 10.F.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.5 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009);. Amendment No. 6 effective as of October 26, 2006 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.M to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006). |
| +10.E                     | Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).  |
| +10.F                     |   |

Edgar Filing: EL PASO CORP/DE - Form 10-K

Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.G.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 3 effective December 15, 2004 to the Supplemental Benefits Plan (Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 4 to the Supplemental Benefits Plan effective as of December 31, 2004 (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on March 7, 2006); Amendment No. 5 effective as of January 1, 2007 to the Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).

**Table of Contents**

| <b>Exhibit Number</b> | <b>Description</b>  |
|-----------------------|---|
| *+10.G                | Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998.   |
| +10.G.1               | Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.H.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).  |
| +10.G.2               | Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.H.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).   |
| +10.H                 | Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).; Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan(Exhibit 10.I.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 5 effective as of January 1, 2007 to the Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008). |
| +10.I                 | 2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.I to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of January 1, 2007 to the 2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.J.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).  |
| +10.J                 | Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.K.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.J.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).  |
| +10.K                 | Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.L to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.L.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan (Exhibit 10.L.2 to   |

our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan (Exhibit 10.L.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.L.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 5 effective as of October 26, 2006 to the Strategic Stock Plan (Exhibit 10.J to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).

- +10.L Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.O to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.O.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management

**Table of Contents**

| <b>Exhibit<br/>Number</b> | <b>Description</b>  |
|---------------------------|---|
|                           | Employees (Exhibit 10.O.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management (Exhibit 10.O.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.O.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 5 effective as of October 26, 2006 to the Corporation Omnibus Plan for Management Employees (Exhibit 10.I to our Quarterly Report on Form-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006). |
| +10.M                     | Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later(Exhibit 10.T to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).  |
| +10.N                     | Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto (Exhibit 10.F to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).  |
| +10.O                     | Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 15, 2004 (Exhibit 10.R to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).   |
| *+10.P                    | El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005.   |
| +10.P.1                   | Amendment No. 1 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of October 26, 2006 (Exhibit 10.P to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).  |
| +10.P.2                   | Amendment No. 2 effective as of January 1, 2007 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).   |
| +10.P.3                   | Amendment No. 3 effective as of January 1, 2008 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).   |
| +10.Q                     | El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated effective May 19, 2010 (incorporated by reference to Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 20, 2010).  |
| *10.R                     | Form of stock option and restricted stock award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan.  |
| *10.R.1                   |   |

Form of performance share award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan.

- \*+10.S 2005 Supplemental Benefits Plan effective as of January 1, 2005.
- +10.S.1 Amendment No. 1 effective as of January 1, 2007 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.BB.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
- +10.S.2 Amendment No. 2 effective as of January 1, 2008 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005. (Exhibit 10.BB.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
- 10.T Third Amended and Restated Credit Agreement dated as of November 16, 2007, among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A.,

**Table of Contents**

| <b>Exhibit<br/>Number</b> | <b>Description</b>   |
|---------------------------|--|
|                           | as administrative agent and as collateral agent (Exhibit 10.V to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).  |
| 10.U                      | Third Amended and Restated Security Agreement dated as of November 16, 2007, made by among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.T.1 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010). |
| 10.V                      | Third Amended and Restated Subsidiary Guarantee Agreement dated as of November 16, 2007, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.C to our Current Report on Form 8-K filed with the SEC on November 21, 2007).  |
| 10.W                      | Credit Agreement dated as of May 3, 2010 among Ruby Pipeline, L.L.C, as the Borrower, Société Générale, as the Administrative Agent, Deutsche Bank Trust Company Americas, as the Common Security Trustee, Construction/Term Loan Lenders, DSRA Issuing Banks, and Revolving Loan Lender/Issuing Bank (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 11, 2010).   |
| 10.X                      | Non-Completion Loan Guaranty by El Paso Corporation, as the Guarantor, in favor of Société Générale as the Administrative Agent, dated as of May 3, 2010 (incorporated by reference to Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on May 11, 2010).   |
| 10.Y                      | Registration Rights Agreement dated September 24, 2010 (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).  |
| *12                       | Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.   |
| *21                       | Subsidiaries of El Paso Corporation.   |
| *23.A                     | Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.   |
| *23.B                     | Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers, LLP (Four Star Oil & Gas Company and Citrus Corp. and Subsidiaries)  |
| *23.C                     | Consent of Ryder Scott Company, L.P.   |
| *31.A                     | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.  |
| *31.B                     | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.  |
| *32.A                     | Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.  |
| *32.B                     | Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.  |

- \*99.A Ryder Scott Company, L.P. reserve report for El Paso Exploration & Production Company and Four Star Oil & Gas Company as of December 31, 2010.
- \*101.INS XBRL Instance Document.
- \*101.SCH XBRL Schema Document.
- \*101.CAL XBRL Calculation Linkbase Document.
- \*101.DEF XBRL Definition Linkbase Document.
- \*101.LAB XBRL Labels Linkbase Document.
- \*101.PRE XBRL Presentation Linkbase Document.

171