EL PASO CORP/DE
Form S-1
August 23, 2005

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As filed with the Securities and Exchange Commission on August 23, 2005

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

EL PASO CORPORATION
(Exact Name of Registrant As Specified In its Charter)

Delaware	**4922**	**76-0568816**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

El Paso Building **1001 Louisiana Street** **Houston, Texas 77002** **(713) 420-2600** *(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)*	**Robert W. Baker, Esq.** **El Paso Building** **1001 Louisiana Street** **Houston, Texas 77002** **(713) 420-2600** *(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)*

Copies To:

Andrews Kurth LLP
600 Travis, Suite 4200
Houston, Texas 77002
Attention: G. Michael O Leary, Esq.
(713) 220-4200

Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this Registration Statement, as determined in light of market conditions and other factors.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, other than securities offered only in connection with dividend or interest reinvestment plans, check the following box. þ

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act of 1933, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act of 1933, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Share(1)	Proposed Maximum Aggregate Offering Price(1)	Amount of Registration Fee
4.99% Convertible Perpetual Preferred Stock, par value $0.01 per share	750,000	$1,000	$750,000,000	$88,275
Common Stock, par value $3.00 per share(2)	57,581,550(3)	N/A	N/A	(2)

(1) Estimated solely for purposes of calculating the registration fee pursuant to Rule 457 under the Securities Act of 1933, as amended.

(2) The registrant will receive no consideration for the issuance of these shares of common stock upon conversion of the preferred stock. Therefore, pursuant to Rule 457(i), no filing fee is required with respect to these shares of common stock registered hereby.

(3) Represents the maximum number of shares of common stock which may be issued upon conversion of the preferred stock registered hereby.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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We will amend and complete the information in this prospectus. The selling security holders may not sell these securities or accept your offer to buy them until the documentation filed with the SEC relating to these securities has been declared effective by the SEC. This prospectus is not an offer to sell these securities or our solicitation of your offer to buy these securities in any jurisdiction where that would not be permitted or legal.

SUBJECT TO COMPLETION AUGUST 23, 2005

El Paso Corporation

750,000 Shares of 4.99% Convertible Perpetual Preferred Stock

(liquidation preference $1,000 per share)

57,581,550 Shares of Common Stock

issuable upon conversion of the Preferred Stock

This prospectus relates to the offer and resale, from time to time, of up to 750,000 shares of 4.99% Convertible Perpetual Preferred Stock (liquidation preference $1,000 per share), par value $0.01 per share, and the shares of our common stock, par value $3.00 per share, issuable upon the conversion of the preferred stock. These shares are being offered to the public market by those individuals named in the section of this prospectus entitled Selling Stockholders, as described under the section of this prospectus entitled Plan of Distribution. We originally issued the preferred stock in a private placement on April 15, 2005. The selling stockholders will receive the proceeds from the sale of the preferred stock and common stock, but we will bear the costs relating to the registration of the preferred stock and common stock. For a more detailed description of the preferred stock, see Description of the Preferred Stock beginning on page 143.

Our common stock trades on the New York Stock Exchange under the symbol EP. On August 22, 2005, the closing sale price of our common stock was $11.34 per share.

The shares of preferred stock issued in the initial private placement are eligible for trading in the Portal^{SM} Market of the Nasdaq Stock Market, Inc. Shares of preferred stock sold using this prospectus, however, will no longer be eligible for trading in the Portal^{SM} Market of the Nasdaq Stock Market, Inc. We do not intend to list the preferred stock on any national securities exchange or automated quotation system.

Investing in the preferred stock or common stock involves risks. See Risk Factors beginning on page 7.

Neither the Securities and Exchange Commission nor any other regulatory body has approved or disapproved of these securities or passed on the accuracy or adequacy of this prospectus or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is August , 2005.

You should rely only on the information contained in this prospectus or to which we have referred you. We have not authorized anyone to provide you with different information. This prospectus may only be used where it is legal to sell these securities. We are not making an offer of these securities in any state where such an offer is not permitted. The information in this offering memorandum may only be accurate on the date of this prospectus or the dates of the documents incorporated by reference in this prospectus. You should not assume that the information contained in this prospectus or incorporated by reference herein is accurate as of any other date.

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INDUSTRY AND MARKET DATA

We have obtained some industry and market share data from third party sources that we believe to be reliable. In many cases, however, we have made statements in this prospectus regarding our industry and our position in the industry based on our experience in the industry and our own investigation of market conditions. We cannot assure you that any of these assumptions are accurate or that our assumptions correctly reflect our position in the industry.

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

/d	= per day
Bbl	= barrels
BBtu	= billion British thermal units
BBtue	= billion British thermal unit equivalents
Bcf	= billion cubic feet
Bcfe	= billion cubic feet of natural gas equivalents
MBbls	= thousand barrels
Mcf	= thousand cubic feet
MDth	= thousand dekatherms
Mcfe	= thousand cubic feet of natural gas equivalents
Mgal	= thousand gallons
MMBbls	= million barrels
MMBtu	= million British thermal units
MMcf	= million cubic feet
MMcfe	= million cubic feet of natural gas equivalents
MMWh	= thousand megawatt hours
MTons	= thousand tons
MW	= megawatt
NGL	= natural gas liquids
TBtu	= trillion British thermal units
Tcfe	= trillion cubic feet of natural gas equivalents

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

NON-GAAP FINANCIAL MEASURES

Our management uses EBIT to assess the operating results and effectiveness of our business segments. EBIT and the related ratios presented in this prospectus are supplemental measures of our performance that are not required by, or recognized as being in accordance with, GAAP. EBIT should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with GAAP or as an alternative to cash flow from operating activities as a measure of our operating liquidity. For a reconciliation of our EBIT (by segment) to our consolidated net income (loss) for the quarters and six months ended June 30, 2005 and 2004, and for each of the three years ended December 31, 2004, see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations.

We define EBIT as net income (loss) adjusted for (1) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (2) income taxes, (3) interest and debt expense and (4) distributions on preferred interests of consolidated subsidiaries. Our businesses consist of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries from this measure so that investors may evaluate our operating results independently from our financing methods or capital structure. We believe that EBIT is helpful to our investors because it allows them to more effectively evaluate the operating performance of our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

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WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy reports, statements or other information we file at the SEC s public reference room at 100 F Street, N.E., Washington, D.C., 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of public reference room. Our SEC filings are also available to the public through the web site maintained by the SEC at *http://www.sec.gov.*

This prospectus is part of a registration statement on Form S-1 that we have filed with the SEC. As allowed by SEC rules, this prospectus does not contain all the information you can find in the registration statement or the exhibits filed with the registration statement. Whenever a reference is made in this prospectus to an agreement or other document of El Paso, be aware that such reference is not necessarily complete and that you should refer to the exhibits that are filed with the registration statement for a copy of the agreement or other document. You may review a copy of the registration statement at the SEC s public reference room in Washington, D.C., as well as through the SEC s website as described above. You may also obtain any of the documents referenced in this prospectus from us free of charge, excluding any exhibits to those documents unless the exhibit is specifically incorporated by reference as an exhibit in this prospectus, by requesting them in writing or by telephone from us at the following address:

El Paso Corporation
Office of Investor Relations
El Paso Building
1001 Louisiana Street
Houston, Texas 77002
Telephone No.: (713) 420-2600

You should read this prospectus and any prospectus supplement together with the registration statement and the exhibits filed with the registration statement. The information contained in this prospectus speaks only as of its date unless the context specifically indicates otherwise.

We have not authorized any person to give any information or to make any representation that differs from, or add to, the information discussed in this prospectus. Therefore, if anyone gives you different or additional information, you should not rely on it.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus includes statements that constitute forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations of us and our affiliates. These statements may relate to, but are not limited to, information or assumptions about earnings per share, capital and other expenditures, dividends, financing plans, capital structure, cash flow, liquidity, pending legal and regulatory proceedings and claims, including environmental matters, future economic performance, operating income, cost savings, management s plans, goals and objectives for future operations and growth. These forward-looking statements generally are accompanied by words such as intend, anticipate, believe, estimate, exp should or similar expressions. It should be understood that these forward-looking statements are necessarily estimates reflecting the best judgment of our senior management, not guarantees of future performance. They are subject to a number of assumptions, risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the forward-looking statements.

Undue reliance should not be placed on forward-looking statements, which speak only as of the date of this prospectus.

For a description of risks relating to us and our business, see Risk Factors beginning on page 7 of this prospectus.

All subsequent written and oral forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this section and any other cautionary statements that may accompany such forward-looking statements. We do not undertake any obligation to release publicly any revisions to these forward-looking statements to reflect events or circumstances after the date of this document or to reflect the occurrence of unanticipated events, unless the securities laws require us to do so.

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SUMMARY

This summary highlights some basic information from this prospectus to help you understand our business, the preferred stock and the common stock issuable upon conversion thereof. It does not contain all of the information that is important to you. You should carefully read this prospectus to understand fully the terms of the preferred stock and the common stock subject to issuance upon conversion thereof, as well as the tax and other considerations that are important to you in making your investment decision. You should pay special attention to the Risk Factors beginning on page 7 of this prospectus and the section entitled Cautionary Statement Regarding Forward-Looking Statements on page iii of this prospectus to determine whether an investment in the preferred stock is appropriate for you. For purposes of this offering memorandum, except where we are describing the terms of the preferred stock and the common stock subject to issuance upon conversion thereof, and unless the context otherwise indicates, when we refer to El Paso, us, we, our, ours, or issuer, we are describing El Paso Corporation, together with its subsidiaries the context otherwise indicates, all references to the preferred stock are to the 4.99% Convertible Perpetual Preferred Stock described in this prospectus. With respect to any description of the terms of the preferred stock or the common stock subject to issuance upon conversion thereof, such references refer only to El Paso Corporation, and not to its subsidiaries.

Our Business

We are an energy company originally founded in 1928 in El Paso, Texas. Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own North America s largest natural gas pipeline system and are a large independent natural gas producer. We also own and operate an energy marketing and trading business, a power business, midstream assets and investments, and have an investment in a small telecommunications business. Our power business primarily consists of international assets.

Since the end of 2001, our business activities have largely been focused on maintaining our core businesses of pipelines and production, while attempting to liquidate or otherwise divest of those businesses and operations that were not core to our long-term objectives, or that were not performing consistently with the expectations we had for them at the time we made the investment. Our overall objective during this period has been to reduce debt and improve liquidity, while at the same time investing in our core business activities. Our actions during this period have significantly impacted our financial condition, with the sale of almost $10 billion of operating assets. These actions have also produced significant financial losses through asset impairments, realized losses on asset sales and diminishment of income producing potential on businesses sold.

In late 2003 and early 2004, we appointed a new chief executive officer and several new members of the executive management team. Following a period of assessment, we announced that our long-term business strategy would principally focus on our core pipeline and production businesses. Our businesses are owned through a complex legal structure of companies that reflect the acquisitions and growth in our business from 1996 to 2001. As part of our long range strategy, we are actively working to reduce the complexity of our corporate structure. See our ownership structure chart on page 98.

We believe that 2004 was a watershed year for us. We were able to meet and exceed a number of the goals established under our 2003 Long Range Plan. As part of our efforts in 2004:

- We focused capital investment on our core pipeline and production businesses, where in 2002, 2003 and 2004, we spent 87 percent, 91 percent, and 97 percent of our total capital dollars;

- We completed the sale of a number of assets and investments including international production properties, a substantial portion of our general and limited partnership interests in GulfTerra Energy Partners, L.P., a publicly traded limited partnership, a significant portion of our worldwide petroleum markets operations, a significant portion of our domestic power generation operations and our merchant LNG business. Total proceeds from these sales were approximately $3.3 billion;

- We reduced our net debt (debt, net of cash) by $3.4 billion in 2004, lowering our net debt to $17.1 billion (debt of $19.2 billion, less cash and cash equivalents of $2.1 billion) as of December 31, 2004; and

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We continued our cost-reduction efforts with a goal of achieving $150 million of savings by the end of 2006.

In 2004 we focused on expanding our pipeline operations and beginning the turnaround of our production business. During the year, we completed major expansions in our pipeline operations, including our Cheyenne Plains project, to provide transmission outlets for natural gas supply in the Rocky Mountains, and we are moving forward on our Cypress projects to fulfill demand for natural gas in the southeastern United States, primarily Florida. Additionally, we continue to work in recontracting capacity on our systems and have been successful to date in these efforts. In our production operations, we instituted a new, more rigorous, risk analysis process which emphasizes strict capital discipline. Over the second half of 2004, this process resulted in a shifting of capital to areas with higher returns and improved drilling results and helped us to begin the stabilization of our domestic production. In addition, we have recently made several strategic acquisitions of production properties in Texas and acquired the interests held by one of the third parties under our net profits interest agreements.

In 2005, we are working to achieve our long-range goals by:

Simplifying our capital structure;

Continuing to focus on expansions in our core pipeline business and completing the turnaround of our production business;

Selling additional assets that we expect will generate proceeds from $1.8 billion to $2.2 billion;

Reducing outstanding debt (net of cash) to $15 billion by the end of 2005; and

Continuing to reduce costs to achieve the cost savings outlined in our Long Range Plan.

For a further description of our business, see the information set forth under the caption Business that begins on page 98 of this prospectus.

Recent Developments

Settlement of Equity Security Units

On August 17, 2005, we issued approximately 13.6 million shares of our common stock in settlement of the purchase contracts associated with the outstanding equity security units for approximately $272.1 million.

Asset Sales

On August 8, 2005, we announced that we had agreed to sell certain south Louisiana midstream entities to Crosstex Energy, L.P. for $500 million. The transaction is subject to regulatory approval, other closing conditions, and post-closing adjustments. We expect to report a pre-tax gain of approximately $400 million on this sale, which is expected to close in the fourth quarter of 2005. We are also in the process of selling our interest in a processing plant in south Texas, which will conclude our midstream asset sales.

Appointment of Principal Officer

Effective as of August 10, 2005, D. Mark Leland, the former executive vice president and chief financial officer of El Paso Production Holding Company, became our executive vice president and chief financial officer. Mr. Leland replaced D. Dwight Scott, who resigned as our executive vice president and chief financial officer to join GSO Capital Partners LP.

The Offering and this Prospectus

Preferred stock offered by the Selling Holders	Up to 750,000 shares of 4.99% Convertible Perpetual Preferred Stock, par value $0.01 per share.
Common stock offered by the Selling Holders	Up to 57,581,550 shares, based upon an initial conversion price of $13.03 per share of common stock. The conversion price is subject

	to adjustment as described in Description of the Preferred Stock Adjustments to the Conversion Rate.
Liquidation preference	$1,000 per share of preferred stock.
Dividends	Holders of preferred stock are entitled to receive, when, as and if declared by our board of directors, out of funds legally available therefor, cash dividends at the rate of 4.99% per annum of the liquidation preference, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year commencing July 1, 2005. Dividends on the preferred stock will accumulate from the most recent date as to which dividends will have been paid or, if no dividends have been paid, from the date of initial issuance. Accumulated but unpaid dividends accumulate at the annual rate of 4.99%. For so long as the preferred stock remains outstanding, (1) we will not declare, pay or set apart funds for the payment of any dividend or other distribution with respect to any junior stock or parity stock and (2) neither we nor any of our subsidiaries will, subject to certain exceptions, redeem, purchase or otherwise acquire for consideration junior stock or parity stock through a sinking fund or otherwise, in each case unless we have paid or set apart funds for the payment of all accumulated and unpaid dividends, including liquidated damages, if any, with respect to the shares of preferred stock and any parity stock for all preceding dividend periods. See Description of the Preferred Stock Dividends.
Use of proceeds	All of the shares of preferred stock and common stock offered hereby are being sold by the selling stockholders. We will not receive any proceeds from the sale of preferred stock and common stock in this offering. See Use of Proceeds.
Conversion	The preferred stock is convertible, at the option of the holder, at any time into shares of our common stock at a conversion rate of 76.7754 shares of our common stock per $1,000 liquidation preference of preferred stock, which represents an initial conversion price of approximately $13.03 per share of common stock. The conversion rate may be adjusted for certain reasons as described under the caption Description of the Preferred Stock Adjustments to the Conversion Rate, but will not be adjusted for accumulated and unpaid dividends or for liquidated damages, if any. Upon conversion, holders will not receive any cash payment representing accumulated and unpaid dividends, if any. In addition, if a holder elects to convert its shares of preferred stock in connection with the occurrence, prior to April 5, 2015, of a fundamental change, the holder will be entitled to receive additional shares of common stock upon conversion or, in lieu thereof, we may under certain circumstances elect to adjust the conversion rate and the related conversion obligation such that the preferred stock will be convertible into shares of the acquiring or surviving company, in each case as described under Description of the Preferred Stock Make Whole Payment Upon the Occurrence of a Fundamental Change. If we declare a distribution consisting exclusively of cash to holders of our common stock (excluding (1) dividends or distributions in connection with our liquidation, dissolution or winding up and

(2) any quarterly cash dividend on our shares of common stock to the extent that the aggregate cash dividend per share amount of our common stock in any quarter does not exceed \$0.04, which amount we refer to as the dividend threshold amount), the conversion rate will be adjusted by multiplying the applicable conversion rate by the following fraction:

$$\frac{\text{Market Price of Common Stock} \quad \textit{minus} \quad \text{Dividend Threshold Amount}}{\text{Market Price of Common Stock} \quad \textit{minus} \quad \text{Per Share Distribution Amount}}$$

If an adjustment is required to be made as a result of a distribution that is not a quarterly dividend, the dividend threshold amount will be deemed to be zero.

See Description of the Preferred Stock Adjustments to the Conversion Rate for additional discussion of adjustments that may be made to the conversion rate.

Mandatory conversion	On or after April 5, 2010, we may, at our option, cause the preferred stock to be automatically converted into that number of shares of common stock that are issuable at the then prevailing conversion rate. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days (including the last trading day of such period), the closing price of our common stock exceeds 130% of the then prevailing conversion price of the preferred stock.
Limited optional redemption	On or after April 5, 2010, we will have the option to redeem all outstanding shares of preferred stock if (1) the total number of preferred shares then outstanding is less than 10% of the total number of such shares issued in this offering and (2) the closing price of our common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day before we give notice of redemption equals or exceeds the conversion price in effect on such day. We will pay the redemption price in cash.
Fundamental change	If a fundamental change (as described under Description of the Preferred Stock Conversion Rights Fundamental Change Requires Us to Redeem Shares of Preferred Stock at the Option of the Holder) occurs prior to April 1, 2015, each holder of shares of preferred stock will, subject to legally available funds, have the right to require us to redeem any or all of its shares at a redemption price equal to 100% of the liquidation preference, plus an amount equal to any accumulated and unpaid dividends, including liquidated damages, if any, to, but excluding, the date of redemption. We will pay the redemption price in cash. Holders will have no other right to require us to redeem the preferred stock at any time. Our ability to redeem all or a portion of the preferred stock for cash is subject to our obligation to repay or repurchase any outstanding debt that may be required to be repaid or repurchased in connection with a fundamental change and to any contractual restrictions contained in the terms of any indebtedness that we have at that time. If a fundamental change occurs at a time when we are prohibited from redeeming shares

of preferred stock for cash, we could seek the consent of our lenders to redeem the preferred stock or attempt to refinance the debt containing such prohibition.

In addition, holders of shares of preferred stock shall not have the right to require us to repurchase shares of preferred stock upon a

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	fundamental change unless and until our board of directors has approved such fundamental change or elected to take a neutral position with respect to such fundamental change.
Voting rights	Holders of preferred stock will not have any voting rights except as set forth below or as otherwise from time to time required by law. Whenever (1) dividends on the preferred stock or any other class or series of stock ranking on a parity with the preferred stock with respect to the payment of dividends are in arrears for dividend periods, whether or not consecutive, containing in the aggregate a number of days equivalent to six calendar quarters, or (2) we fail to pay the redemption price on the date shares of preferred stock are called for redemption (whether the redemption is pursuant to the optional redemption provisions or the redemption is in connection with a fundamental change) then, immediately prior to the next annual meeting of shareholders, the total number of directors constituting the entire board will automatically be increased by two and, in each case, the holders of preferred stock (voting separately as a class with all other series of preferred stock upon which like voting rights have been conferred and are exercisable) will be entitled to vote for the election of such directors at the next annual meeting of stockholders and at each subsequent meeting until all dividends accumulated or the redemption price on the preferred stock have been fully paid or set apart for payment. Directors elected by the holders of the preferred stock shall not be divided into classes of the board of directors and the term of office of all directors elected by the holders of preferred stock will terminate immediately upon the termination of the right of the holders of preferred stock to vote for directors and upon such termination the total number of directors constituting the entire board will automatically be reduced by two. Holders of shares of preferred stock will have one vote for each share of preferred stock held.
Ranking	The preferred stock will be, with respect to dividend rights and rights upon liquidation, winding up or dissolution: junior to all our existing and future debt obligations; junior to every other class or series of our capital stock other than (1) our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the preferred stock and (2) any other class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the preferred stock; on a parity with any class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the preferred stock; senior to our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the preferred stock; and effectively junior to all of our subsidiaries (1) existing and future liabilities and (2) capital stock held by others.
Trading	The shares of preferred stock issued in the initial private placement are eligible for trading in the Portal^{SM} Market of the Nasdaq Stock Market, Inc. Shares of preferred

stock sold using this prospectus, however, will no longer be eligible for trading in the Portal[SM] Market of the Nasdaq Stock Market, Inc. We do not intend to list

	the preferred stock on any national securities exchange or automated quotation system.
NYSE symbol for our common stock	Our common stock is traded on the New York Stock Exchange under the symbol EP.

For further information regarding the preferred stock, including, among other things, more complete descriptions of our dividend obligations, the conversion of the preferred stock, and the anti-dilution adjustments and voting rights applicable to the preferred stock, please see Description of the Preferred Stock.

Ratio of Earnings to Fixed Charges

	For The Years Ended December 31,					**For The Six Months Ended June 30,**	
	2000	**2001**	**2002**	**2003**	**2004**	**2004**	**2005**
Ratio of earnings to fixed charges[(1)]	1.31x						

(1) Earnings were inadequate to cover fixed charges by $393 million, $1,440 million, $1,121 million and $1,065 million for the years ended December 31, 2001, 2002, 2003 and 2004, respectively, and $77 million and $231 million for the six months ended June 30, 2004 and 2005.

For purposes of computing these ratios, earnings means pre-tax income (loss) from continuing operations before:

- minority interests in consolidated subsidiaries;
- income or loss from equity investees, adjusted to reflect actual distributions from equity investments; and
- fixed charges;

less:

- capitalized interest; and
- preferred returns on consolidated subsidiaries.

Fixed charges means the sum of the following:

- interest costs, not including interest on rate refunds;
- amortization of debt costs;
- that portion of the rental expense which we believe represents an interest factor;
- preferred stock dividends; and
- preferred returns on consolidated subsidiaries.

Risk Factors

An investment in the preferred stock and the common stock subject to issuance upon conversion thereof involves certain risks that a potential investor should carefully evaluate prior to making an investment in the preferred stock. See Risk Factors beginning on page 7.

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RISK FACTORS

Before you invest in our preferred stock and common stock, you should consider the risks, uncertainties and factors that may adversely affect us that are discussed below.

Risks Relating to the Preferred Stock

The preferred stock ranks junior to all of our liabilities.

In the event of our bankruptcy, liquidation or winding-up, our assets will be available to pay obligations on the preferred stock, including the purchase of your shares of the preferred stock for cash upon a fundamental change, only after all of our indebtedness and other liabilities have been paid. In addition, we are a holding company and the preferred stock will effectively rank junior to all existing and future liabilities of our subsidiaries and any capital stock of our subsidiaries held by others. The rights of holders of the preferred stock to participate in the distribution of assets of our subsidiaries will rank junior to the prior claims of that subsidiary s creditors and any other equity holders. Consequently, if we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets remaining to pay amounts due on any or all of the preferred stock then outstanding. We and our subsidiaries may incur substantial amounts of additional debt and other obligations that will rank senior to the preferred stock.

We may not be able to pay cash dividends on the preferred stock.

We are required to pay all declared dividends on the preferred stock in cash. Our existing revolving credit facilities and indentures limit, and any indentures and other financing agreements that we enter into in the future will likely limit, our ability to pay cash dividends on our capital stock. Specifically, under our existing revolving credit agreement, we may pay cash dividends and make other distributions on or in respect of our capital stock, including the preferred stock, only if certain financial tests are met. In addition, the indentures or other credit facilities of certain of our subsidiaries include limitations on the ability of such subsidiaries to pay dividends or make other distributions to us. For a description of the restrictive covenants included in our existing revolving credit agreement and references to restrictive covenants to which we or our subsidiaries are subject, see Notes to our Consolidated Financial Statements, Note 15 on page F-81. In the event that any of our revolving credit facilities, indentures or other financing agreements in the future restrict our ability to pay cash dividends on the preferred stock, we will be unable to pay cash dividends on the preferred stock unless we can refinance amounts outstanding under those agreements. Furthermore, in the event the credit facilities, indentures or other financing agreements of our subsidiaries limit the ability of such subsidiaries to pay dividends or make distributions to us, our ability to pay dividends on the preferred stock could be adversely affected.

Under Delaware law, cash dividends on capital stock may only be paid from surplus or, if there is not surplus, from the corporation s net profits for the then current or the preceding fiscal year. Unless we continue to operate profitably, our ability to pay cash dividends on the preferred stock would require the availability of adequate surplus, which is defined as the excess, if any, of our net assets (total assets less total liabilities) over our capital. Further, even if adequate surplus is available to pay cash dividends on the preferred stock, we may not have sufficient cash to pay dividends on the preferred stock.

There is no public market for the preferred stock.

The preferred stock is eligible for trading in PORTAL. Shares of preferred stock sold using this prospectus will no longer be eligible for trading in PORTAL, and will not be listed for trading on any national securities exchange or on the National Association of Securities Dealers Automated Quotation System (Nasdaq). In addition, we cannot assure when or how many shares of preferred stock may be sold pursuant to this prospectus, which will be a factor affecting the depth and liquidity of the market, if any, for shares of our preferred stock. Accordingly, there may not be development of, or significant liquidity in, any market for shares of preferred stock sold using this prospectus. If a market for the preferred stock were to develop, the preferred stock could trade at prices that may be higher or lower than the price paid to any of the selling stockholders for shares sold pursuant to this prospectus depending upon many factors, including the price of

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our common stock into which the preferred stock may be converted, prevailing interest rates, our operating results and the markets for similar securities.

We may not be able to pay the redemption price of the preferred stock in cash upon a fundamental change. We also could be prevented from paying dividends on shares of the preferred stock.

In the event of a fundamental change you will have the right to require us to purchase with cash all your shares of preferred stock. However, we may not have sufficient cash to purchase your shares of preferred stock upon a fundamental change or may be otherwise unable to pay the purchase price in cash.

In addition, holders of shares of preferred stock will not have the right to require us to repurchase shares of preferred stock upon a fundamental change unless our board of directors has approved such fundamental change or elected to take a neutral position with respect to such fundamental change.

Further, because we are a holding company, our ability to purchase the preferred stock for cash may be limited by restrictions on our ability to obtain funds for such repurchase through dividends from our subsidiaries.

If you convert your shares of preferred stock into shares of common stock, you may experience immediate dilution.

If you convert your shares of preferred stock into shares of common stock, you may experience immediate dilution because the per share conversion price of the preferred stock is higher than the then net tangible book value per share of our outstanding common stock. In addition, you will also experience dilution when and if we issue additional shares of common stock, which we may be required to issue pursuant to options, warrants, our stock option plan or other employee or director compensation plans.

The price of our common stock, and therefore of the preferred stock, may fluctuate significantly, which may make it difficult for you to resell the preferred stock, or common stock issuable upon conversion thereof, when you want or at prices you find attractive.

The price of our common stock on the New York Stock Exchange constantly changes. We expect that the market price of our common stock will continue to fluctuate. Because the preferred stock is convertible into shares of our common stock, volatility or depressed prices for our common stock could have a similar effect on the trading price of the preferred stock. Holders who have received common stock upon conversion will also be subject to the risk of volatility and depressed prices.

Our stock price can fluctuate as a result of a variety of factors, many of which are beyond our control. In addition, the stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

The additional shares of our common stock payable on our preferred stock in connection with a fundamental change may not adequately compensate you for the lost option time value of your shares of our preferred stock as a result of such fundamental change.

If a fundamental change occurs, we will, in certain circumstances, increase the conversion rate of our preferred stock by a number of additional shares of common stock. The number of additional shares of our common stock will be determined based on the date on which the fundamental change becomes effective, and the price paid per share of common stock in the fundamental change transaction as described under Description of the Preferred Stock Conversion Rights Make Whole Payment Upon the Occurrence of a Fundamental Change. While the increase in the conversion rate upon conversion is designed to compensate you for the lost option time value of your shares of preferred stock as a result of the fundamental change, the increase is only an approximation of this lost value and may not adequately compensate you for your loss. If the price paid per share of common stock in the fundamental change transaction is less than the price per share of the common stock at the date of issuance of our preferred stock or above a specified price, there will be no increase in the conversion rate. In addition, in certain circumstances, upon a fundamental change arising from our acquisition by a public company, we may elect to adjust the conversion rate as described under Description of the Preferred Stock Conversion Rights Make Whole Payment Upon the Occurrence of a Fundamental Change and, if we so elect, holders of shares of our preferred stock will not be entitled to the increase in the conversion rate described above.

We may issue additional series of preferred stock that rank equally to the preferred stock as to dividend payments and liquidation preference.

Our amended and restated certificate of incorporation and the certificate of designation for the preferred stock do not prohibit us from issuing additional series of preferred stock that would rank equally to the preferred stock as to dividend payments and liquidation preference. Including the 750,000 shares of the preferred stock issued for sale pursuant to this prospectus our amended and restated certificate of incorporation provides that we have the authority to issue 50,000,000 shares of preferred stock. The issuances of other series of preferred stock could have the effect of reducing the amounts available to the preferred stock in the event of our liquidation. It may also reduce dividend payments on the preferred stock if we do not have sufficient funds to pay dividends on all preferred stock outstanding and outstanding parity preferred stock.

Future issuances of preferred stock may adversely affect the market price for our common stock.

Additional issuances and sales of preferred stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at a time and price favorable to us.

We may not have sufficient earnings and profits in order for distributions on the preferred stock to be treated as dividends.

The dividends payable by us on the preferred stock may exceed our current and accumulated earnings and profits, as calculated for U.S. federal income tax purposes, at the time of payment. If that occurs, it will result in the amount of the dividends that exceed such earnings and profits being treated first as a return of capital to the extent of the holder s adjusted tax basis in the preferred stock, and the excess, if any, over such adjusted tax basis as capital gain. Such treatment will generally be unfavorable for corporate holders and may also be unfavorable to certain other holders. See Certain United States Federal Income Tax Considerations U.S. Holders.

Our corporate documents and Delaware law contain provisions that could discourage, delay or prevent a change in control of our company even if some stockholders might consider such a development favorable, which may adversely affect the price of our common stock.

Provisions in our amended and restated certificate of incorporation and amended and restated by-laws may discourage, delay or prevent a merger or acquisition involving us that our stockholders may consider favorable. For example, our amended and restated certificate of incorporation authorizes our board of directors to issue shares of preferred stock to which special rights are attached, including voting and dividend rights.

We are also subject to the anti-takeover provisions of Section 203 of the Delaware General Corporation Law. Under these provisions, if anyone becomes an interested stockholder, we may not enter into a business combination with that person for three years without special approval, which could discourage a third party from making a takeover offer and could delay or prevent a change of control. For purposes of Section 203, interested stockholder means, generally, someone owning 15% or more of our outstanding voting stock or an affiliate of ours that owned 15% or more of our outstanding voting stock during the past three years, subject to certain exceptions as described in Section 203.

Upon a change in control as defined in our existing credit facilities, the lenders under such existing credit facilities will have the right to require us to repay all of our outstanding obligations under the facility. In addition, the holders of certain series of indebtedness of certain of our subsidiaries will have the right upon the occurrence of a change of control as defined in such indebtedness or the indenture relating thereto, subject to

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certain conditions, to require us to repurchase their notes at a price equal to 100% or 101% of their principal amount, plus accrued and unpaid interest to the date of repurchase. Because a change of control as defined in our existing credit facilities and as defined in our subsidiaries indentures provides for repurchase rights under terms that are different from the definition of a fundamental change under the preferred stock offered hereby, holders of our other indebtedness may have the ability to require us to repay or repurchase those debt obligations before the holders of the preferred stock would have such repurchase rights.

Risks Related to Our Business

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

The success of our pipeline business depends, in part, on factors beyond our control.

Most of the natural gas and natural gas liquids we transport and store are owned by third parties. As a result, the volume of natural gas and natural gas liquids involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire, or to remarket unsubscribed capacity on our pipeline systems:

- service area competition;
- expiration and/or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- future weather conditions;
- price competition;
- drilling activity and availability of natural gas supplies;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- increased availability or popularity of alternative energy sources such as hydroelectric power;
- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands, and

unfavorable movements in natural gas and liquids prices.

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

Substantially all of our pipeline subsidiaries revenues are generated under contracts which expire periodically and must be renegotiated and extended or replaced. We cannot assure you that we will be able to

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extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace contracts could be adversely affected by factors we cannot control, including:

competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by our interstate pipelines;

changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;

reduced demand and market conditions in the areas we serve;

the availability of alternative energy sources or gas supply points; and

regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues, earnings and cash flows.

Fluctuations in energy commodity prices could adversely affect our pipeline businesses.

Revenues generated by our transmission, storage, and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. Increased prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas-fired power plants. Increased prices could also result from industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies loss of customer base. We also experience earnings volatility when the amount of gas utilized in operations differs from amounts we receive for that purpose. The success of our transmission, storage and processing operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional suppliers from interconnecting pipelines to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate 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 or facilities. We retain a fixed percentage of natural gas transported for use as fuel and to replace lost and unaccounted for gas, and we are at risk for the difference between the retained amount and actual gas consumed or lost and unaccounted. Pricing volatility may also impact the value of under or over recoveries of this retained gas. If natural gas prices in the supply basins connected to our pipeline systems are higher on a delivered basis to our off-system markets than delivered prices from other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Fluctuations in energy prices are caused by a number of factors, including:

regional, domestic and international supply and demand;

availability and adequacy of transportation facilities;

energy legislation;

federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids;

abundance of supplies of alternative energy sources; and

political unrest among oil producing countries.

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

Our future financial condition, revenues, results of operations, cash flows and future rate of growth depend primarily upon the prices we receive for our natural gas and oil production. Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current

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world geopolitical conditions. The prices for natural gas and oil are subject to a variety of additional factors that are beyond our control. These factors include:

the level of consumer demand for, and the supply of, natural gas and oil;

commodity processing, gathering and transportation availability;

the level of imports of, and the price of, foreign natural gas and oil;

the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

domestic governmental regulations and taxes;

the price and availability of alternative fuel sources;

the availability of pipeline capacity;

weather conditions;

market uncertainty;

political conditions or hostilities in natural gas and oil producing regions;

worldwide economic conditions; and

decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives.

Further, because approximately 82 percent of our proved reserves at December 31, 2004 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices than we are to changes in oil prices. Declines in natural gas and oil prices would not only reduce revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could adversely affect the financial results of our production business. Changes in natural gas and oil prices can have a significant impact on the calculation of our full cost ceiling test. A significant decline in natural gas and oil prices could result in a downward revision of our reserves and a write-down of the carrying value of our natural gas and oil properties, which could be substantial, and would negatively impact our net income and stockholders equity.

The success of our natural gas and oil exploration and production businesses is dependent, in part, on factors that are beyond our control.

In addition to prices, the performance of our natural gas and oil exploration and production businesses is dependent, in part, upon a number of factors that we cannot control, including:

the results of future drilling activity;

our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;

our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive conditions;

increased competition in the search for and acquisition of reserves;

future drilling, production and development costs, including drilling rig rates and oil field services costs;

future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;

increased federal or state regulations, including environmental regulations, or adverse court decisions that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;

decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives;

- declines in production volumes, including those from the Gulf of Mexico; and
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

Our natural gas and oil drilling and producing operations involve many risks and may not be profitable.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks. The nature of the risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured. As a result, we could incur substantial costs that could adversely affect our future results of operations, cash flows or financial condition.

In addition, in our drilling operations we are subject to the risk that we will not encounter commercially productive reservoirs. New wells drilled by us may not be productive, or we may not recover all or any portion of our investment in those wells. Drilling for natural gas and oil can be unprofitable, not only because of dry holes but wells that are productive may not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs.

Estimating our reserves, production and future net cash flow is difficult.

Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. As a result, our reserve estimates are inherently imprecise. Also, the use of a 10 percent discount factor for estimating the value of our reserves, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our production business or the natural gas and oil industry, in general, are subject. Any significant variations from the interpretations or assumptions used in our estimates or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially.

Our reserve data represents an estimate. You should not assume that the present values referred to in this prospectus represent the current market value of our estimated natural gas and oil reserves. The timing of the production and the expenses from development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Changes in the present value of these reserves could cause a write-down in the carrying value of our natural gas and oil properties, which could be substantial, and would negatively affect our net income and stockholders equity.

As of December 31, 2004, approximately 29 percent of our estimated proved reserves were undeveloped. Recovery of undeveloped 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 proved undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

The success of our power activities depends, in part, on many factors beyond our control.

The success of our remaining domestic and international power projects could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- increases in the costs of generation, including increases in fuel costs;

- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the United States and in foreign jurisdictions;
- our ability to negotiate successfully, and enter into advantageous power purchase and supply agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions, excessive reserve margins and the implementation of conservation programs;
- risks incidental to the operation and maintenance of power generation facilities;
- the inability of customers to pay amounts owed under power purchase agreements;
- the increasing price volatility due to deregulation and changes in commodity trading practices; and
- over-capacity of generation in markets served by the power plants we own or in which we have an interest.

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

Some of our subsidiaries use futures, swaps and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. To the extent we have positions that are not designated or qualify as hedges, changes in commodity prices, interest rates, volatility, correlation factors, the liquidity of the market could cause our revenues, net income and cash requirements to be volatile.

We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments involves estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase, or interest rates were to change. The use of derivatives also requires the posting of cash collateral with our counterparties which can impact our working capital (current assets and liabilities) when commodity prices or interest rates change. For additional information concerning our derivative financial instruments, see Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk on pages 69 and 97, Notes to Condensed Consolidated Financial Statements, Note 8, on page F-16, and Notes to Consolidated Financial Statements, Note 10, on page F-73.

Our businesses are subject to the risk of payment defaults by our counterparties.

We frequently extend credit to our counterparties following the performance of credit analysis. Despite performing this analysis, we are exposed to the risk that we may not be able to collect amounts owed to us. Although in many cases we have collateral to secure the counterparty s performance, it could be inadequate and we could suffer credit losses.

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States, including material investment exposure in our power, pipeline and production projects in Brazil and Pakistan, are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems; and
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties.

Retained liabilities associated with businesses that we have sold could exceed our estimates.

We have sold a significant number of assets over the years, including the sale of many assets since 2001. Pursuant to various purchase and sale agreements relating to businesses and assets that we have divested, we have either retained certain liabilities or indemnified certain purchasers against liabilities that they might incur in the future. These liabilities in many cases relate to breaches of warranties, environmental, tax, litigation, personal injury 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 reserves in the future and these amounts could be material. In addition, as we exit businesses, we have experienced substantial reductions and turnover in our workforce that previously supported the ownership and operation of such assets. There is the risk that such reductions and turnover in our workforce could result in errors or mistakes in managing the businesses that we are exiting prior to closing. There is also the risk that such reductions could result in errors or mistakes in managing the retained liabilities after closing, including the lack of any historical knowledge with regard to such assets and businesses in managing the liabilities or defending any associated litigation.

Risks Related to Legal and Regulatory Matters

Ongoing litigation and investigations related to our financial statements associated with our reserve estimates and hedges could significantly adversely affect our business.

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves and because of the manner in which we applied the accounting rules related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. As a result of this reduction in reserve estimates, several class action lawsuits were filed against us and several of our subsidiaries. The reserve revisions are also the subject of investigations by the SEC and the U.S. Attorney and the hedging matters are also the subject of an investigation by the U.S. Attorney and the SEC, any of which could result in significant fines against us. These investigations and lawsuits, and possible future claims based on these same facts, may further negatively impact our credit ratings and place further demands on our liquidity. We cannot provide assurance at this time that the effects and results of these or other investigations or of the class action lawsuits will not be material to our financial conditions, results of operations and liquidity.

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

As described under the caption Note 10. Commitment and Contingencies Governmental Investigations of the Notes to Condensed Consolidated Financial Statements and Note 17. Commitments and Contingencies Governmental Investigations of the Notes to Consolidated Financial Statements, included in this prospectus, we are subject to numerous governmental investigations including those involving our round trip trades, price reporting of transactional data to the energy trade press, natural gas and oil reserve revisions, sales of crude oil of Iraqi origin under the United Nation s Oil for Food Program and the rupture of one of our pipelines near Carlsbad, New Mexico. These investigations involve, among others, one or more of the following governmental agencies: the SEC, FERC, U.S. Attorney, grand jury of the U.S. District Court for the Southern District of New York, U.S. Senate Permanent Subcommittee of Investigations, House of Representatives International Relations Subcommittee, U.S. Department of Transportation Office of Pipeline Safety, National Transportation Safety Board and the Department of Justice. We are cooperating with the governmental agency or agencies in each of these investigations. The outcome of each of these investigations is uncertain. Because of the uncertainties associated with the ultimate outcome of each of these investigations and the costs to the Company of responding and participating in these on-going investigations, no assurance can be given that the ultimate costs to, and sanction(s), if any, that may be imposed upon, us will not have a material adverse effect on our business, financial condition or results of operation.

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

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. In setting authorized rates of return in a few recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as

much competition or risks as interstate pipelines. The inclusion of these companies creates downward pressure on approved tariff rates. If our pipelines tariff rates were reduced in a future proceeding, if our pipelines volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition or because of regulatory pressure, the profitability of our pipeline businesses could be reduced.

In addition, increased regulatory requirements relating to the integrity of our pipelines requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures.

Further, state agencies that regulate our pipelines local distribution company customers could impose requirements that could impact demand for our pipelines services.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. Some of these sites have been designated as Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies, including matters relating to methyl tertiary-butyl ether found in water supplies and the clean up of, or exposure to, hazardous substances.

Compliance with environmental laws and regulations can require significant costs, such as costs of installing and maintaining pollution controls and clean-up and damages, including natural resources damages, arising out of contaminated properties, and the failure to comply with environmental laws and regulations may result in fines and penalties being imposed. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating pollution control and clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- potential changes in environmental laws and regulations, including changes in the interpretation and enforcement thereof.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties, and these amounts could be material. For additional information concerning our environmental matters, see Business Legal Proceedings, on page 123, Notes to Condensed Consolidated Financial Statements, Note 10, on page F-19, and Notes to Consolidated Financial Statements, Note 17, on page F-89.

Costs of litigation matters and other contingencies could exceed our estimates.

We are involved in various lawsuits in which we or our subsidiaries have been sued. We also have other contingent liabilities and exposures. Although we believe we have established appropriate reserves for these liabilities, we could be required to set aside additional reserves in the future and these amounts could be material. For additional information concerning our litigation matters and other contingent liabilities, see Notes to Condensed Consolidated Financial Statements, Note 10, on page F-19, and Notes to Consolidated Financial Statements, Note 17, on page F-89.

Our system of internal controls ensures the accuracy or completeness of our disclosures and a loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.

Section 404 of the Sarbanes-Oxley Act of 2002 (SOA), requires us to provide an annual report on our internal controls over financial reporting, including an assessment as to whether or not our internal controls over financial reporting are effective. We are also required to have our auditors attest to our assessment and to opine on the effectiveness of our internal controls over financial reporting. Based upon such review, we concluded that as of December 31, 2004 we did not maintain effective internal control over financial reporting. As more fully described on pages F-118 through F-120, we identified several deficiencies in internal control over financial reporting that management concluded constituted material weaknesses at December 31, 2004. In addition, we reported restatements of our financial statements on April 8, 2005 and June 16, 2005 as a result of the material weaknesses that existed at December 31, 2004. Since December 31, 2004, we have made various changes in our internal controls, as described in Controls and Procedures on pages F-37 to F-38, which we believe remediate the material weaknesses previously identified by the company. We are in the process of testing these changes. If, upon completing the testing and evaluation of our remediated internal controls as required by Section 404 of the SOA, we determine that our remediation has been ineffective, or we identify additional deficiencies in our internal controls over financial reporting, we could be subjected to additional regulatory scrutiny, future delays in filing our financial statements and a loss of public confidence in the reliability of our financial statements, which could have a negative impact on our liquidity, access to capital markets, financial condition and the market value of our common stock.

In addition, we do not expect that our disclosure controls and procedures or our internal controls over financial reporting will prevent all mistakes, errors and fraud. Any system of internal controls, no matter how well designed or implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that the benefits of controls must be considered relative to their costs. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Therefore, any system of internal controls is subject to inherent limitations, including the possibility that controls may be circumvented or overridden, that judgments in decision-making can be faulty, and that misstatements due to mistakes, errors or fraud may occur and may not be detected. Also, while we document our assumptions and review financial disclosures with the Audit Committee of our Board of Directors, the regulations and literature governing our disclosures are complex and reasonable persons may disagree as to their application to a particular situation or set of facts.

Risks Related to Our Liquidity

We have significant debt and below investment grade credit ratings, which have impacted and will continue to impact our financial condition, results of operations and liquidity.

We have significant debt and significant debt service and debt maturity obligations. The ratings assigned to our senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody s Investor Service (Moody s) and B- by Standard & Poor s. These ratings have increased our cost of capital and our operating costs, particularly in our trading operations, and could impede our access to capital markets. Moreover, we must retain greater liquidity levels to operate our business than if we had investment grade credit ratings. Our debt maturities as of December 31, 2004 for 2005, 2006 and 2007 are $948 million, $1,155 million and $835 million, respectively. If our ability to generate or access capital becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected. See Notes to Condensed Consolidated Financial Statements, Note 9, on page F-17 and Notes to Consolidated Financial Statements, Note 15, on page F-81, for further discussions of our debt.

We may not achieve all of the objectives set forth in our Long-Range Plan in a timely manner or at all.

Our ability to achieve the objectives of our Long-Range Plan, as well as the timing of their achievement, if at all, is subject, in part, to factors beyond our control. These factors include (1) our ability to raise cash

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from asset sales, which may be impacted by our ability to locate potential buyers in a timely fashion and obtain a reasonable price, (2) our ability to manage our working capital, (3) our ability to generate additional cash by improving the performance of our pipeline and production operations, (4) our ability to exit the power and trading businesses in the manner and within the time period we expect, (5) our ability to significantly reduce debt, and (6) our ability to preserve sufficient cash flow to service our debt and other obligations. If we fail to achieve in a timely manner the targets of our Long-Range Plan, our liquidity or financial position could be materially adversely affected. In addition, it is possible that any of the asset sales contemplated by our Long-Range Plan could be at prices that are below our current book value for the assets, which could result in losses that could be substantial.

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

Our debt and other financing obligations contain restrictive covenants and cross-acceleration provisions, which become more restrictive over time. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit and from borrowing under our $3 billion credit agreement, and could accelerate our long-term debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

Our $3 billion credit agreement is collateralized by our equity interests in Tennessee Gas Pipeline Company, ANR Pipeline Company, El Paso Natural Gas Company, Colorado Interstate Gas Company, Wyoming Interstate Company Ltd., Southern Gas Storage Company and ANR Storage Company. A breach of the covenants under the $3 billion agreement could permit the lender to exercise their rights to the collateral, and we could be required to liquidate these interests.

Our ability to access capital markets is limited to private placements or filing new registration statements as a result of the restatement of our historical financial results.

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves and because of the manner in which we applied the accounting rules related to our hedges of our natural gas production and certain other derivatives. As a result of the time required to complete these revisions, our 2003 Form 10-K and our 2004 Forms 10-Q were not filed in a timely manner. As a result, until February 2006, our ability to access approximately $926 million of capacity under our existing shelf registration statement without filing additional disclosure information with the SEC is restricted. The additional disclosure requirements, and any related review by the SEC, could be expensive and impede our ability to access capital in a timely fashion. If our ability to access capital becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected.

We are subject to financing and interest rate exposure risks.

Our future success depends on our ability to access capital markets and obtain financing at cost effective rates. Our ability to access financial markets and obtain cost-effective rates in the future are dependent on a number of factors, many of which we cannot control, including changes in:

- our credit ratings;
- interest rates;
- the structured and commercial financial markets;
- market perceptions of us or the natural gas and energy industry;
- changes in tax rates due to new tax laws;
- our stock price; and
- changes in market prices for energy.

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USE OF PROCEEDS

All of the shares of preferred stock and common stock offered hereby are being sold by the selling stockholders. We will not receive any proceeds from the sale of preferred stock by selling stockholders pursuant to this prospectus or shares of common stock issuable upon conversion thereof.

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SELECTED FINANCIAL DATA

The following historical selected financial data excludes certain of our international natural gas and oil production operations and our petroleum markets and coal mining businesses, which are presented as discontinued operations in our financial statements for all periods. The selected financial data below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations beginning on page 22 of this prospectus and Financial Statements beginning on page F-1 of this prospectus. These selected historical results are not necessarily indicative of results to be expected in the future.

	As of or for the Year Ended December 31,					As of or for the Six Months Ended June 30,	
	2004 (Restated)(3)	2003 (Restated)(1)(2)(3)	2002 (Restated)(1)	2001	2000(4)	2005(5)	2004
					(Unaudited)	(Unaudited)	(Unaudited)
	(In millions, except per common share amounts)						
Operating Results Data:							
Operating revenues	$ 5,874	$ 6,668	$ 6,881	$ 10,186	$ 6,179	$ 2,366	$ 3,081
Income (loss) from continuing operations available to common stockholders(6)	$ (833)	$ (595)	$ (1,242)	$ (223)	$ 481	$ (140)	$ (191)
Net income (loss)	$ (947)	$ (1,883)	$ (1,875)	$ (447)	$ 665	$ (132)	$ (191)
Basic income (loss) per common share from continuing operations	$ (1.30)	$ (0.99)	$ (2.22)	$ (0.44)	$ 0.98	$ 0.22	$ (0.30)
Diluted income (loss) per common share from continuing operations	$ (1.30)	$ (0.99)	$ (2.22)	$ (0.44)	$ 0.95	$ (0.22)	$ (0.30)
Cash dividends declared per common share(7)	$ 0.16	$ 0.16	$ 0.87	$ 0.85	$ 0.82	$ 0.08	$ 0.08
Basic average common shares outstanding	639	597	560	505	494	640	639
Diluted average common shares outstanding	639	597	560	505	506	640	639
Financial Position Data:							
Total assets(8)	$ 31,383	$ 36,943	$ 41,923	$ 44,271	$ 43,992	$ 29,676	$ 31,383
Long-term financing obligations (9)	18,241	20,275	16,106	12,840	11,206	16,379	18,241

Securities of subsidiaries(9)	367	447	3,420	4,013	3,707	59	367
Stockholders equity	3,438	4,346	5,749	6,666	6,145	3,800	3,438

(1) During the completion of the financial statements for the year ended December 31, 2004, we identified an error in the manner in which we had originally adopted the provisions of SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, in 2002. Upon adoption of these standards, we incorrectly adjusted the cost of investments in unconsolidated affiliates and the cumulative effect of change in accounting principle for the excess of our share of the affiliates fair value of the net assets over their original cost, which we believed was negative goodwill. The amount originally recorded as a cumulative effect of accounting change was $154 million and related to our investments in Citrus Corporation, Portland Natural Gas, several Australian investments and an investment in the Korea Independent Energy Corporation. We subsequently determined that the amounts we adjusted were not negative goodwill, but rather amounts that should have been allocated to the long-lived assets underlying our investments. As a result, we were required to restate our 2002 financial statements to reverse the amount we recorded as a cumulative effect of an accounting change on January 1, 2002. This adjustment also impacted a deferred tax adjustment and an unrealized loss we recorded on our Australian investments during 2002, requiring a further restatement of that year. The restatements also affected the investment, deferred tax liability and stockholders equity balances we reported as of December 31, 2002 and 2003. See Notes to Consolidated Financial Statements, Note 1, on page F-46, for a further discussion of the restatements.

(2) After filing our 2004 Form 10-K, we determined that in our discontinued Canadian exploration and production operations, we had previously recorded deferred tax benefits of $82 million in 2003 in continuing operations that we have now properly reflected in discontinued operations.

(3) After filing our amended 2004 Form 10-K, we identified errors related to the accounting and reporting of foreign currency translation adjustments (CTA) on several of our foreign operations. In addition, we determined that upon initially recognizing U.S. deferred income taxes on our investment in certain foreign operations, we did not properly allocate taxes to CTA. These errors resulted in us having to record additional income tax benefits in 2003 in our continuing operations of $10 million and in our discontinued operations of $35 million. In 2004, we determined that we should have recorded a reduction in our loss from discontinued operations of $32 million and an increase in our loss from continuing operations of $31 million, related to CTA balances and related tax adjustments. As a result of these errors, we restated our 2003 and 2004 financial statements, related quarterly information, and interim period financial statements. See Notes to Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements, Note 1, on pages F-46 and F-8 for a further discussion of the restatements.

(4) These amounts are derived from unaudited financial statements. Such amounts were restated in 2003 for the accounting impact of adjustments to our historical reserve estimates.

(5) During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

(6) We incurred losses of $1.1 billion in 2004, $1.2 billion in 2003 and $0.9 billion in 2002 related to impairments of assets and equity investments as well as restructuring charges related to industry changes and the related realignment of our businesses in response to those changes. In 2003, we also entered into an agreement in principle to settle claims associated with the western energy crisis of 2000 and 2001. This settlement resulted in charges of $104 million in 2003 and $899 million in 2002, both before income taxes. In addition, we incurred ceiling test charges of $5 million, $5 million and $1,895 million in 2003, 2002 and 2001 on our full cost natural gas and oil properties. During 2001, we merged with The Coastal Corporation and incurred costs and asset impairments related to this merger that totaled approximately $1.5 billion. We recognized net losses of $349 million and $297 million for the six months ended June 30, 2005 and June 30, 2004, related to sales and impairments of long-lived assets and equity investments. For further discussions of events affecting comparability of our results in 2004, 2003 and 2002, see Notes to Consolidated Financial Statements, Notes 2 through 5, on pages F-58 to F-68.

(7) Cash dividends declared per share of common stock represent the historical dividends declared by El Paso for all periods presented.

(8) Decreases in 2002, 2003, 2004 and the first quarter of 2005, were a result of asset sales activities during these periods. See Notes to Condensed Consolidated Financial Statements, Note 3, on page F-11, and Notes to Consolidated Financial Statements, Note 3, on page F-62.

(9) The increases in total long-term financing obligations in 2002 and 2003 was a result of the consolidations of our Chaparral and Gemstone power investments, the restructuring of other financing transactions, and the reclassification of securities of subsidiaries as a result of our adoption of SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,* during 2003.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Our Management s Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed beginning on page 7. Certain historical financial information in this section has been restated, as further described in Notes to Condensed Consolidated Financial Statements, Note 1, on page F-8, and Notes to Condensed Consolidated Financial Statements, Note 1, on page F-46.

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations for the years ended December 31, 2004, 2003 and 2002, as well as the six month periods ended June 30, 2005 and 2004, and should be read in conjunction with our historical consolidated financial statements and accompanying notes. In mid 2004, we discontinued our Canadian and certain other international natural gas and oil production operations. Our results for all periods reflect these operations as discontinued.

Years Ended December 31, 2004, 2003 and 2002

Overview

Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own North America s largest natural gas pipeline system and are a large independent natural gas producer. We also own and operate an energy marketing and trading business, a power business, midstream assets and investments, and have an investment in a small telecommunications business. Our power business primarily consists of international assets.

Since the end of 2001, our business activities have largely been focused on maintaining our core businesses of pipelines and production, while attempting to liquidate or otherwise divest of those businesses and operations that were not core to our long-term objectives, or that were not performing consistently with the expectations we had for them at the time we made the investment. Our overall objective during this period has been to reduce debt and improve liquidity, while at the same time invest in our core business activities. Our actions during this period have significantly impacted our financial condition, with the sale of almost $10 billion of operating assets. These actions have also resulted in significant financial losses through asset impairments, realized losses on asset sales and reduction of income from the businesses sold.

We believe that 2004 was a watershed year for us. We were able to meet and exceed a number of the goals established under our 2003 Long Range Plan. As part of our efforts in 2004:

- We focused capital investment on our core pipeline and production businesses, where in 2002, 2003 and 2004, we spent 87 percent, 91 percent, and 97 percent of our total capital dollars;
- We completed the sale of a number of assets and investments including international production properties, a substantial portion of our general and limited partnership interests in GulfTerra, a significant portion of our worldwide petroleum markets operations, a significant portion of our domestic power generation operations and our merchant LNG business. Total proceeds from these sales were approximately $3.3 billion;
- We reduced our net debt (debt, net of cash) by $3.4 billion in 2004, lowering our net debt to $17.1 billion as of December 31, 2004; and
- We continued our cost-reduction efforts with a goal of achieving $150 million of savings by the end of 2006.

As noted above, in 2004, we focused on expanding our pipeline operations and beginning the turnaround of our production business. During the year, we completed major expansions in our pipeline operations, including our Cheyenne Plains project to provide transmission outlets for natural gas supply in the Rocky Mountains, and we are moving forward on our Cypress project to fulfill demand for natural gas in the southeastern United

States, primarily Florida. Additionally, we continue to work in recontracting capacity on our systems and have been successful to date in these efforts. In our production operations, we instituted a new, more rigorous, risk analysis process which emphasizes strict capital discipline. Over the second half of 2004, this process resulted in a shifting of capital to areas with higher returns, improved drilling results and helped us to begin the stabilization of our domestic production. In addition, we have recently made several strategic acquisitions of production properties in Texas. In 2005, we will continue to work to achieve our long-range goals by:

- Simplifying our capital structure;
- Continuing to focus on expansions in our core pipeline business and completing the turnaround of our production business;
- Selling additional assets that we expect will generate proceeds from $1.8 billion to $2.2 billion;
- Reducing outstanding debt (net of cash) to $15 billion by the end of 2005; and
- Continuing to reduce costs to achieve the cost savings outlined in our plan.

Capital Resources and Liquidity

We rely on cash generated from our internal operations as our primary source of liquidity, as well as available credit facilities, project and bank financings, proceeds from asset sales and the issuance of long-term debt, preferred securities and equity securities. From time to time, we have also used structured financing transactions that are sometimes referred to as off-balance sheet arrangements. We expect that our future funding for working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources, although we do not expect to use off-balance sheet arrangements to the same degree in the future. Each of our existing and projected sources of cash are impacted by operational and financial risks that influence the overall amount of cash generated and the capital available to us. For example, cash generated by our business operations may be impacted by, among other things, changes in commodity prices, demands for our commodities or services, success in recontracting existing contracts, drilling success and competition from other providers or alternative energy sources. Collateral demands or recovery of cash posted as collateral are impacted by natural gas prices, hedging levels and the credit quality of us and our counterparties. Cash generated by future asset sales may depend on the condition and location of the assets and the number of interested buyers. In addition, our future liquidity will be impacted by our ability to access capital markets which may be restricted due to our credit ratings, general market conditions, and by limitations on our ability to access our existing shelf registration statement as further discussed in Note 15 to our Consolidated Financial Statements, on page F-81. For a further discussion of risks that can impact our liquidity, see Risk Factors beginning on page 7.

Our subsidiaries are a significant potential source of liquidity to us and they participate in our cash management program to the extent they are permitted under their financing agreements and indentures. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or requirements, we either provide cash to them or they provide cash to us.

During 2004, we took additional steps to reduce our overall debt obligations. These actions included entering into a new $3 billion credit agreement and selling entities with substantial debt obligations as follows (in millions):

Debt obligations as of December 31, 2003	$	21,732
Principal amounts borrowed[(1)]		1,513
Repayment of principal[(2)]		(3,370)
Sale of entities[(3)]		(887)
Other		208
Total debt as of December 31, 2004	$	19,196

(1) Includes proceeds from a $1.25 billion term loan under our new $3 billion credit agreement.

(2) Includes $850 million of repayments under our previous $3 billion revolving credit facility.

(3) Consists of $815 million of debt related to Utility Contract Funding and $72 million of debt related to Mohawk River Funding IV.

For a further discussion of our long-term debt, other financing obligations and other credit facilities, see Notes to Consolidated Financial Statements, Note 15, on page F-81.

As of December 31, 2004, we had available liquidity as follows (in billions):

Available cash	$ 1.8
Available capacity under our $3 billion credit agreement	0.6
Net available liquidity at December 31, 2004	$ 2.4

In addition to our available liquidity, we expect to generate significant operating cash flow in 2005. We will supplement this operating cash flow with proceeds from asset sales, which we expect will range from $1.8 billion to $2.2 billion over the next 12 to 24 months (of which $0.7 billion has already closed through March 25, 2005). We will also utilize proceeds from our financing activities as needed. In March 2005, we completed a $200 million financing at CIG. The proceeds will be used to refinance $180 million of bonds at CIG that will mature in June 2005 and for other general purposes.

In 2005 we expect to spend between $1.6 billion and $1.7 billion on capital investments mainly in our core pipeline and production businesses. We have also spent approximately $0.3 billion on acquisitions in our natural gas and oil operations through March 25, 2005, and may make additional acquisitions during 2005. As of December 31, 2004, our contractual debt maturities for 2005 and 2006 were approximately $0.6 billion and $1.3 billion. Additionally, we had approximately $0.8 billion of zero-coupon debentures that have a stated maturity of 2021, but contain an option whereby the holders can require us to redeem the obligations in February 2006. We currently expect the holders to exercise this right, which combined with our contractual maturities could require us to retire up to $2.1 billion of debt in 2006. Through March 25, 2005 we have prepaid approximately $0.7 billion of our Euro denominated debt originally scheduled to mature in March 2006 and $0.2 billion of our zero-coupon debentures. As a result of these prepayments, we have reduced our 2006 expected maturities to approximately $1.2 billion which will give us greater financial flexibility next year.

Finally, in 2005 we may also prepay a number of other obligations including derivative positions in our marketing and trading operations and possibly amounts outstanding for the Western Energy Settlement, among other items. These prepayments could total approximately $1.1 billion. Of this amount, we have already prepaid approximately $240 million of obligations through the transfer of derivative contracts to Constellation Power in March 2005, in connection with the sale of Cedar Brakes I and II.

Our net available liquidity includes our $3 billion credit agreement. As of December 31, 2004, we had borrowed $1.25 billion as a term loan and issued approximately $1.2 billion of letters of credit under this agreement. The availability of borrowings under this credit agreement and our ability to incur additional debt is subject to various conditions as further described in Note 15 to our Consolidated Financial Statements, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements. The financial coverage ratios under our $3 billion credit agreement change over time. However, these covenants currently require our Debt to Consolidated EBITDA not to exceed 6.5 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in the credit agreement. As of December 31, 2004, our ratio of Debt to Consolidated EBITDA was 4.88 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 1.91 to 1.

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Our $3 billion credit agreement is collateralized by our equity interests in TGP, EPNG, ANR, CIG, WIC, Southern Gas Storage Company, and ANR Storage Company. Based upon a review of the covenants contained in our indentures and our other financing obligations, acceleration of the outstanding amounts under the credit agreement could constitute an event of default under some of our other debt agreements. If there was an event of default and the lenders under the credit agreement were to exercise their rights to the collateral, we could be required to liquidate our interests in these entities that collateralize the credit agreement. Additionally, we would be unable to obtain cash from our pipeline subsidiaries through our cash management program in an event of default under some of our subsidiaries indentures. Finally, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

We believe we will be able to meet our ongoing liquidity and cash needs through the combination of available cash and borrowings under our $3 billion credit agreement. We also believe that the actions we have taken to date will allow us greater financial flexibility for the remainder of 2005 and into 2006 than we had in 2004. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans. These factors are discussed in detail beginning on page 17.

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Overview of Cash Flow Activities for 2004 Compared to 2003

For the years ended December 31, 2004 and 2003, our cash flows are summarized as follows:

	2004	2003 (Restated)
	(In billions)	
Cash inflows		
Continuing operating activities		
Net loss before discontinued operations	$ (0.8)	$ (0.6)
Non-cash income adjustments	2.4	1.8
Payment on Western Energy Settlement	(0.6)	
Change in assets and liabilities	0.1	1.1
	1.1	2.3
Continuing investing activities		
Net proceeds from the sale of assets and investments	1.9	2.5
Net proceeds from restricted cash	0.6	
Other	0.1	
	2.6	2.5
Continuing financing activities		
Net proceeds from the issuance of long-term debt	1.3	3.6
Borrowings under long-term credit facility		0.5
Proceeds from the issuance of common stock	0.1	0.1
Net discontinued operations activity	1.0	0.4
	2.4	4.6
Total cash inflows	$ 6.1	$ 9.4
Cash outflows		
Continuing investing activities		
Additions to property, plant, and equipment	$ 1.8	$ 2.4
Net cash paid to acquire Chaparral and Gemstone		1.1
Net payments of restricted cash		0.5
Other		0.1
	1.8	4.1
Continuing financing activities		
Payments to retire long-term debt and redeem preferred interests	2.5	4.1
Payments of revolving credit facilities	0.9	1.2
Dividends paid to common stockholders	0.1	0.2
Other	0.1	
	3.6	5.5

Total cash outflows		5.4		9.6
Net change in cash	$	0.7	$	(0.2)

Cash From Continuing Operating Activities

Overall, cash generated from continuing operating activities decreased by $1.2 billion largely due to a payment of $0.6 billion related to the principal litigation under the Western Energy Settlement in 2004 and higher cash recovered from margin deposits in 2003. We recovered $0.7 billion of cash in 2003 from our margin deposits by substituting letters of credit for cash on deposit as compared to $0.1 billion recovered in 2004.

Cash From Continuing Investing Activities

For the year ended December 31, 2004, net cash provided by our continuing investing activities was $0.8 billion. During the year, we received net proceeds of approximately $0.9 billion from sales of our domestic power assets as well as $1.0 billion from the sales of our general and limited partnership interests in GulfTerra and various other Field Services assets. We also released restricted cash of $0.6 billion out of escrow, which was paid to the settling parties to the Western Energy Settlement as discussed above.

Our 2004 capital expenditures included the following (in billions):

Production exploration, development and acquisition expenditures	$ 0.7
Pipeline expansion, maintenance and integrity projects	1.0
Other (primarily power projects)	0.1
Total capital expenditures and net additions to equity investments	$ 1.8

In 2005, we expect our total capital expenditures, including acquisitions, to be approximately $1.9 billion, divided approximately equally between our Production and Pipelines segments. In 2004, our Production segment received funds of approximately $110 million from third parties under net profits interest agreements. In March 2005, we purchased all of the interests held by one of the parties to these agreements for $62 million. See Supplemental Financial Information, under the heading Supplemental Natural Gas and Oil Operations (Unaudited) beginning on page F-126, for a further discussion of these agreements.

In September 2004, we incurred significant damage to sections of our offshore pipeline facilities due to Hurricane Ivan. Cost estimates are currently in the $80 million to $95 million range with damage assessment still in progress. We expect insurance reimbursement with the exception of a $2 million deductible for this event; however the timing of such reimbursements may occur later than the capital expenditures on the damaged facilities which may increase our net capital expenditures for 2005.

In January 2005, we sold our remaining interests in Enterprise and its general partner for $425 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million. During 2005, we will continue to divest, where appropriate, our non-core assets based on our long-term business strategy, including additional power assets in Asia and other countries (see Business , on page 98, and Notes to Consolidated Financial Statements, Note 3, on page F-62, for a further discussion of these divestitures and the asset divestitures of our discontinued operations). The timing and extent of these additional sales will be based on the level of market interest and based upon obtaining the necessary approvals.

Cash From Continuing Financing Activities

Net cash used in our continuing financing activities was $1.2 billion for the year ended December 31, 2004. During 2004, our significant financing cash inflows included $1.25 billion borrowed as a term loan under our new $3 billion credit agreement. We also had $1.0 billion of cash contributed by our discontinued operations. Of the amount contributed by our discontinued operations, $0.2 billion was generated from operations, $1.2 billion was received as proceeds from the sales of our Eagle Point and Aruba refineries and our international production operations, primarily in western Canada, and $0.4 billion was used to repay long-term debt related to the Aruba refinery.

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Our significant financing cash outflows included net repayments of $0.9 billion on our previous $3 billion revolving credit facilities during 2004, prior to entering into our new $3 billion credit agreement. We also made $2.5 billion of payments to retire third party long-term debt and redeem preferred interests as we continued in our efforts to reduce our overall debt obligations under our Long-Range Plan. See Notes to Consolidated Financial Statements, Note 15, on page F-81, for further detail of our financing activities.

Contractual Obligations and Off-Balance Sheet Arrangements

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. The following discusses those contingent obligations, often referred to as off-balance sheet arrangements. We also present aggregated information on our contractual cash obligations, some of which are reflected in our financial statements, such as short-term and long-term debt and other accrued liabilities; other obligations, such as operating leases; and capital commitments are not reflected in our financial statements.

Off-Balance Sheet Arrangements and Related Liabilities

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support in the form of 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. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include indemnifications for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

We evaluate our guarantees and indemnity arrangements at the time they are entered into and in each period thereafter to determine whether a liability exists and, if so, if it can be estimated. We record accruals when both these criteria are met. As of December 31, 2004, we had accrued $70 million related to these arrangements. As of December 31, 2004, we also had approximately $40 million of financial and performance guarantees and indemnification arrangements not otherwise reflected in our financial statements.

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Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2004, for each of the years presented (all amounts are undiscounted):

	2005	2006	2007	2008	2009	Thereafter	Total
				(In millions)			
Long-term financing obligations:(1)							
Principal	$ 948	$ 1,155	$ 835	$ 733	$ 2,637	$ 13,031	$ 19,339
Interest	1,356	1,330	1,257	1,191	1,127	11,762	18,023
Western Energy Settlement(2)	44	44	44	44	44	634	854
Other contractual liabilities(3)	31	47	23	22	5	32	160
Operating leases(4)	79	66	51	43	40	163	442
Other contractual commitments and purchase obligations:(5)							
Tolling, transportation and storage(6)	178	144	131	127	122	779	1,481
Commodity purchases(7)	30	28	28	17	10	36	149
Other(8)	151	36	14	15	5	3	224
Total contractual obligations	$ 2,817	$ 2,850	$ 2,383	$ 2,192	$ 3,990	$ 26,440	$ 40,672

(1) See Notes to Consolidated Financial Statements, Note 15, on page F-81.

(2) See Notes to Consolidated Financial Statements, Note 17, on page F-89.

(3) Includes contractual, environmental and other obligations included in other noncurrent liabilities in our balance sheet. Excludes expected contributions to our pension and other postretirement benefit plans of $68 million in 2005 and $209 million for the four year period ended December 31, 2009, because these expected contributions are not contractually required.

(4) See Notes to Consolidated Financial Statements, Note 17, on page F-89.

(5) Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations.

(6) These are commitments for demand charges on our tolling arrangements and for firm access to natural gas transportation and storage capacity.

(7) Includes purchase commitments for natural gas and power.

(8) Includes commitments for drilling and seismic activities in our production operations and various other maintenance, engineering, procurement and construction contracts, as well as service and license agreements, used by our other operations.

Commodity-based Derivative Contracts

We utilize derivative financial instruments in hedging activities, power contract restructuring activities and in our historical energy trading activities. In the tables below, derivatives designated as hedges primarily consist of instruments used to hedge natural gas production. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities as well as other derivative contracts not designated as hedges.

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The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2004:

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges						
Assets	$ 92	$ 33	$	$	$	$ 125
Liabilities	(416)	(222)	(14)	(9)		(661)
Total derivatives designated as hedges	(324)	(189)	(14)	(9)		(536)
Assets from power contract restructuring derivatives[1][2]	105	199	151	210		665
Other commodity-based derivatives						
Exchange-traded positions[3]						
Assets	19	220	76			315
Liabilities	(107)	(1)				(108)
Non-exchange traded positions[2]						
Assets	431	271	186	166	46	1,100
Liabilities[1]	(372)	(448)	(267)	(230)	(51)	(1,368)
Total other commodity-based derivatives	(29)	42	(5)	(64)	(5)	(61)
Total commodity-based derivatives	$ (248)	$ 52	$ 132	$ 137	$ (5)	$ 68

(1) Includes $259 million of intercompany derivatives that eliminate in consolidation and have no impact on our consolidated assets and liabilities from price risk management activities.

(2) In March 2005, we sold our Cedar Brakes I and II subsidiaries and their related restructured power contracts, which had a fair value of $596 million as of December 31, 2004. In connection with this sale, we also assigned or terminated other commodity-based derivatives that had a fair value loss of $240 million as of December 31, 2004.

(3) Exchange-traded positions are traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London Clearinghouse.

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The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2004 and 2003.

	Derivatives Designated as Hedges	Derivatives from Power Contract Restructuring Activities	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
	(In millions)			
Fair value of contracts outstanding at December 31, 2002	$ (21)	$ 968	$ (525)	$ 422
Fair value of contract settlements during the period	15	(405)	602	212
Change in fair value of contracts	(25)	140	(477)	(362)
Original fair value of contracts consolidated as a result of Chaparral acquisition		1,222		1,222
Option premiums received, net			(88)	(88)
Net change in contracts outstanding during the period	(10)	957	37	984
Fair value of contracts outstanding at December 31, 2003	(31)	1,925	(488)	1,406
Fair value of contract settlements during the period	49	(1,132)[1]	284	(799)
Change in fair value of contracts	38	(128)[2]	(513)[3]	(603)
Other commodity-based derivatives designated as hedges	(592)		592	
Option premiums paid, net			64	64
Net change in contracts outstanding during the period	(505)	(1,260)	427	(1,338)
Fair value of contracts outstanding at December 31, 2004	$ (536)	$ 665	$ (61)	$ 68

(1) Includes $861 million and $75 million of derivative contracts sold in conjunction with the sales of Utility Contract Funding and Mohawk River Funding IV in 2004. See Notes to Consolidated Financial Statements, Notes 3 and 5, on pages F-62 and F-68, for additional information on these sales.

(2)

In the fourth quarter of 2004, we recorded a $227 million charge associated with the sale of our Cedar Brakes I and II subsidiaries and their related restructured power contracts. See Notes to Consolidated Financial Statements, Notes 3 and 5, on pages F-62 and F-68, for additional information on this sale.

(3) In the second quarter of 2004, we reclassified a $69 million liability from our Western Energy Settlement obligation to our price risk management activities.

The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement, early termination or, if not settled or terminated, until the end of the period. During 2003, in conjunction with our acquisition of Chaparral, we consolidated a number of derivative contracts. The majority of the value of these contracts was for power purchase agreements and power supply agreements related to power contract restructuring activities conducted by Chaparral.

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In December 2004, we designated a number of our other commodity-based derivative contracts in our Marketing and Trading segment as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004. The combination of these positions and our Production segment s other hedges will result in us receiving the following prices on our natural gas production:

	Volume (TBtu)	Hedge Price[1] (per MMBtu)	Cash Price (per MMBtu)
2005	132	$ 6.75	$ 3.74[2]
2006	86	$ 6.34	$ 4.01[2]
2007	5	$ 3.56	$ 3.56
2008 to 2012	21	$ 3.67	$ 3.67

[1] Our Production segment will record revenues related to these natural gas volumes at this price in their operating results.

[2] The difference between our Production segment s hedge price and the cash price we will receive upon settlement of the derivative transactions was previously recorded as losses in our Marketing and Trading segment.

To stabilize the company s pricing outlook for 2005 to 2007, our Marketing and Trading segment entered into additional contracts that provide a floor price on a portion of our unhedged production in 2005, 2006 and 2007 and a ceiling price on a portion of our unhedged 2006 production. These contracts, which are reported on a mark-to-market basis, will result in us receiving the following cash prices on our natural gas production:

	Floor Price[1] (per MMBtu)	Floor Volume (TBtu)	Ceiling Price[2] (per MMBtu)	Ceiling Volume (TBtu)
2005	$ 6.00	60		
2006	$ 6.00	120	$ 9.50	60
2007	$ 6.00	30		

[1] The floor price is the minimum cash price to be received under the option contract.

[2] The ceiling price is the maximum cash price to be received under the option contract.

Results of Operations

Overview

Since 2001, we have experienced tremendous change in our businesses. Prior to this time, we had grown through mergers and acquisitions and internal growth initiatives, and at the same time had incurred significant amounts of debt and other obligations. In late 2001, driven by the bankruptcy of a number of energy sector participants, followed by increased scrutiny of our debt levels and credit rating downgrades of our debt and the debt of many of our competitors, our focus changed to improving liquidity, paying down debt, simplifying our capital structure, reducing our cost of capital, resolving substantial contingencies and returning to our core natural gas businesses. Accordingly, our operating results during the three year period from 2002 to 2004 have been substantially impacted by a number of significant events, such as asset sales, significant legal settlements and ongoing business restructuring efforts as part of this change in focus.

As of December 31, 2004, our operating business segments were Pipelines, Production, Marketing and Trading, Power and Field Services. These segments provide a variety of energy products and services. They are managed separately and each requires different technology and marketing strategies. Our businesses are divided into two primary business lines: regulated and non-regulated. Our regulated business includes our Pipelines segment, while our non-regulated business includes our Production, Marketing and Trading, Power and Field Services segments.

Our management uses EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries.

Our businesses consist of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results independently from our financing methods or capital structure. We believe EBIT is helpful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

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

	2004 (Restated)[1]	2003 (Restated)[1]	2002 (Restated)[1]
		(In millions)	
Regulated Business			
Pipelines	$ 1,331	$ 1,234	$ 828
Non-regulated Businesses			
Production	734	1,091	808
Marketing and Trading	(539)	(809)	(1,977)
Power	(599)	(28)	12
Field Services	120	133	289
Segment EBIT	1,047	1,621	(40)
Corporate and other	(217)	(852)	(387)
Consolidated EBIT	830	769	(427)
Interest and debt expense	(1,607)	(1,791)	(1,297)
Distributions on preferred interests of consolidated subsidiaries	(25)	(52)	(159)
Income taxes	(31)	479	641
Loss from continuing operations	(833)	(595)	(1,242)
Discontinued operations, net of income taxes	(114)	(1,279)	(425)
Cumulative effect of accounting changes, net of income taxes		(9)	(208)
Net loss	$ (947)	$ (1,883)	$ (1,875)

[1] See Notes to Consolidated Financial Statements, Note 1, on page F-46, for a discussion of the restatements of our 2002, 2003 and 2004 financial statements. The restatement of our 2002 financial statements affected our Pipelines segment results and the amounts reported as a cumulative effect of accounting change in 2002. The restatement of our 2003 financial statements affected the classification of income taxes between continuing and discontinued

operations as well as the amount of income taxes recorded in both continuing and discontinued operations related to certain of our foreign investments with CTA balances. The restatement of our 2004 financial statements affected the amount of losses on long-lived assets, earnings from unconsolidated affiliates and other income for certain foreign operations in our Power and Marketing and Trading segments, in our corporate operations, and in our discontinued operations, as well as the related amount of income taxes recorded on these assets and investments.

As we refocused our activities on our core businesses by divesting of non-core businesses and restructuring our organization, we incurred losses and incremental costs in each year. During this period, we also resolved significant legal contingencies. These items are described in the table below. For a more detailed discussion of these factors and other items impacting our financial performance, see the individual segment

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and other results included in Notes to Consolidated Financial Statements, Notes 3 through 5, on pages F-62 through F-68, and Note 21, on page F-105.

	Operating Segments					
	Pipelines (Restated)	Production	Marketing and Trading	Power (Restated)	Field Services	Corporate & Other
	(In millions)					
2004						
Asset and investment impairments, net of gain (loss) on sales[1]	$ 20	$ (8)	$	$ (994)	$ (7) [2]	$ 3
Restructuring charges	(5)	(14)	(2)	(5)	(1)	(91)
Total	$ 15	$ (22)	$ (2)	$ (999)	$ (8)	$ (88)
2003						
Asset and investment impairments, net of gain (loss) on sales[1]	$ 9	$ (5)	$ 3	$ (525)	$ 9	$ (525)
Ceiling test charges		(5)				
Restructuring charges	(2)	(6)	(16)	(5)	(4)	(91)
Western Energy Settlement [3]	(140)		(26)			(4)
Total	$ (133)	$ (16)	$ (39)	$ (530)	$ 5	$ (620)
2002 (Restated)						
Asset and investment impairments, net of gain (loss) on sales[1]	$ (125)	$ 1	$	$ (642)	$ 129	$ (212)
Ceiling test charges		(5)				
Restructuring charges	(1)		(10)	(14)	(1)	(51)
Western Energy Settlement	(412)		(487)			
Net gain on power contract restructurings[4]				578		
Total	$ (538)	$ (4)	$ (497)	$ (78)	$ 128	$ (263)

[1] Includes net impairments of cost-based investments included in other income and expense.

[2] Includes the gain on our transactions with Enterprise and a goodwill impairment.

(3) Includes $66 million of accretion expense and other charges included in operation and maintenance expense associated with the Western Energy Settlement.

(4) Excludes intercompany transactions related to the UCF restructuring transaction which were eliminated in consolidation.

In our Pipelines segment, we experienced improved financial performance from 2002 to 2004, benefitting from the completion of a number of expansion projects and from the resolution of significant legal issues related to the western energy crisis of 2001.

In our Production segment, we have experienced earnings volatility from 2002 to 2004. During this three-year period, our Production segment sold a significant number of natural gas and oil properties which, coupled with a reduced capital spending program, generally disappointing drilling results and mechanical failures on certain wells, produced a steady decline in production volumes during that timeframe. However, in 2004, we benefited from a favorable pricing environment that allowed for better than anticipated results. The favorable pricing environment is expected to continue to provide benefits to the Production segment during 2005, although its future results will largely be impacted by our production levels. The volumes we produce will be driven by our ability to grow the existing reserve base through a successful drilling program and/or acquisitions.

In our Marketing and Trading segment, we also experienced significant earnings volatility during 2002, 2003 and 2004. Beginning in 2002, we began a process of exiting the trading business. At the same time, the overall energy trading industry has declined. The combination of these actions and events and a decrease in the value of our fixed-price natural gas derivative contracts due to natural gas price increases resulted in substantial losses in our Marketing and Trading segment in 2002, 2003 and 2004. We expect that this segment will continue to experience losses in 2005 as it continues performing under its transportation and tolling contracts. However, due to the repositioning of a number of our natural gas derivative contracts as hedges in December 2004, we expect future losses in this segment to be less than those experienced in 2002 through 2004.

Finally, during 2002 through 2004, as we continued to refocus and restructure our company around our core businesses, we incurred significant charges related to asset sales, impairments and other restructuring costs in our Field Services and Power segments as well as in our corporate results. We also incurred approximately $1.8 billion (including $1.3 billion during 2003) in after tax losses in exiting certain of our international natural gas and oil production operations and our petroleum markets and coal businesses, which are classified as discontinued operations.

Below is a further discussion of the year over year results of each of our business segments, our corporate activities and other income statement items.

Individual Segment Results

Information related to EBIT in our individual segment results and in our corporate activities has been restated. In 2002, the results in our Pipelines segment and the amounts reported as a cumulative effect of accounting change were restated for errors resulting from the misinterpretation of FAS 141 and 142 upon the adoption of these standards. In 2004, our Power and Marketing and Trading segments and corporate operations were restated for the amount of losses on long-lived assets, earnings from unconsolidated affiliates and other income for certain foreign operations with CTA balances. See Notes to Consolidated Financial Statements, Note 1, on page F-46, for a further discussion of the restatement.

Regulated Business Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage, LNG terminalling and related services, primarily in the United States. We face varying degrees of competition in this segment from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the cost of providing services to our customers, including a reasonable return on our invested capital. As a result, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather. In 2004, 84 percent of our transportation service, storage and LNG terminalling revenues were attributable to reservation charges paid by firm customers. The remaining 16 percent of our revenues are variable. We also experience earnings volatility when the amount of natural gas utilized in operations differs from the amounts we receive for that purpose.

Historically, much of our business was conducted through long-term contracts with customers. However, over the past several years some of our customers have shifted from a traditional dependence solely on long-term contracts to a portfolio approach which balances short-term opportunities with long-term commitments. This shift, which can increase the volatility of our revenues, is due to changes in market conditions and competition driven by state utility deregulation, local distribution company mergers, new supply sources, volatility in natural gas prices, demand for short-term capacity and new power plants markets.

In addition, our ability to extend existing customer contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although, at times, we discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2004. Below is the expiration schedule for contracts executed as of December 31, 2004, including those whose terms begin in 2005 or later.

	MDth/d	Percent of Total Contracted Capacity
2005	3,838	13
2006[1][2]	6,414	21
2007	4,539	15
2008 and beyond	15,540	51

(1) Reflects the impact of an agreement, that we entered into to extend 750 MMcf/d of SoCal s current capacity, effective September 1, 2006, for terms of three to five years. The agreement is subject to FERC approval.

(2) Includes approximately 1,564 MMcf/d currently under contract on EPNG s system through 2011 and beyond that is subject to early termination in August 2006 provided customers give timely notice of an intent to terminate.

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for each of the three years ended December 31:

Pipelines Segment Results	2004	2003	2002
			(Restated)
	(In millions, except volume amounts)		
Operating revenues	$ 2,651	$ 2,647	$ 2,610
Operating expenses	(1,522)	(1,584)	(1,822)
Operating income	1,129	1,063	788
Other income	202	171	40
EBIT	$ 1,331	$ 1,234	$ 828
Throughput volumes (BBtu/d)[1]			
TGP	4,519	4,760	4,610
EPNG and MPC	4,235	4,066	4,065

ANR	4,067	4,232	4,130
CIG, WIC and CPG	2,795	2,743	2,768
SNG	2,163	2,101	2,151
Equity investments (our ownership share)	2,798	2,433	2,408
Total throughput	20,577	20,335	20,132

(1) Throughput volumes exclude volumes related to our equity investments in Portland Natural Gas Transmission System, EPIC Energy Australia Trust and Alliance Pipeline, which have been sold. In addition, volumes exclude intrasegment activities. Throughput volumes include volumes related to our Mexico investments which were transferred from our Power segment effective January 1, 2004.

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The following contributed to our overall EBIT increases in 2004 as compared to 2003 and in 2003 as compared to 2002:

	2004 to 2003				2003 to 2002			
	Revenue	Expense	Other	EBIT Impact	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
Contract modifications/terminations	$ (93)	$ 37		$ (56)	$ (52)	$ (7)		$ (59)
Gas not used in operations and other natural gas sales	67	(16)		51	57	(18)		39
Mainline expansions	33	(6)	(6)	21	47	(7)	3	43
Sale of Panhandle fields and other production properties in 2002					(50)	21		(29)
Operation and maintenance costs(1)		(69)		(69)		9		9
Other regulatory matters		(9)	(19)	(28)			18	18
Equity earnings from Citrus			22	22				
Mexico investments	9	(6)	17	20				
Australia investment impairment							141	141
Western Energy Settlement		140		140		272		272
Other(2)	(12)	(9)	17	(4)	35	(32)	(31)	(28)
Total impact on EBIT	$ 4	$ 62	$ 31	$ 97	$ 37	$ 238	$ 131	$ 406

(1) Consists of costs of operations, electric and power purchase costs, shared services allocations and environmental costs.

(2) Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Contract Modifications/ Terminations. Included in this item are (i) the impacts of the expiration of EPNG s historical risk sharing provisions which reduced revenues by $24 million in 2004 (ii) the impact of EPNG s FERC ordered restrictions on remarketing expiring capacity contracts which reduced EPNG s 2003 revenues by $35 million compared to 2002 (iii) the renegotiation or restructuring of several contracts on our pipeline systems, including ANR s contracts with We Energies which contributed to the decrease in revenues by $36 million in 2004 and $12 million in 2003, and (iv) the termination of the Dakota gasification facility contract on ANR s system, which resulted in lower operating revenues and lower operating expenses during 2004, without a significant overall impact on operating income and EBIT.

During 2003, EPNG was prohibited from remarketing expiring capacity contracts due to certain FERC orders. While these capacity restrictions terminated with the completion of Phases I and II of EPNG s Line 2000 Power-up project in 2004, EPNG remains at risk for that portion of capacity which was turned back to it on a permanently released basis. EPNG is able, however, to re-market that capacity subject to the general requirement that it demonstrate that any sale of capacity does not adversely impact its service to its firm customers.

EPNG has entered into an agreement effective September 1, 2006, to extend 750 MMcf/d of capacity on its pipeline system with SoCalGas. The new service agreements will have a primary term of three to five years to serve SoCalGas core customers. SoCalGas is currently contracted on EPNG s system for approximately 1.3 Bcf/d of capacity. EPNG continues in its efforts to market the remaining capacity, including marketing efforts to serve, directly or indirectly, SoCalGas non-core customers or to serve new markets. At this time, we are uncertain whether this remaining capacity will be re-contracted.

Guardian Pipeline, which is owned in part by We Energies, currently provides a portion of We Energies firm transportation requirements and, therefore, directly competes with ANR for a portion of the markets in Wisconsin. This could impact ANR s existing customer contracts as well as future contractual negotiations with We Energies. In addition, ANR has entered into an agreement with a shipper to restructure one of its transportation contracts on its Southeast Leg as well as a related gathering contract. In March 2005, this restructuring was completed and ANR received approximately $26 million, which will be included in its earnings during the first quarter of 2005.

Gas Not Used in Operations and Other Natural Gas Sales. For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to the applicable tariff, relative to the amounts of gas we use for operating purposes, and the price of natural gas. The disposition of gas not needed for operations results in revenues to us, which are driven by volumes and prices during the period. During 2003 and 2004, we recovered, fairly consistently, volumes of natural gas that were not utilized for operations for some of our regulated pipeline systems. These recoveries were and are based on factors such as system throughput, facility enhancements and the ability to operate the systems in the most efficient and safe manner. Additionally, a steadily increasing natural gas price environment during this timeframe also resulted in favorable impacts on our operating results in both 2004 versus 2003 and in 2003 versus 2002. We anticipate that this area of our business will continue to vary in the future and will be impacted by things such as rate actions, some of which have already been implemented, efficiency of our pipeline operations, natural gas prices and other factors.

Expansions. During the three years ended December 31, 2004, we completed a number of expansion projects that have generated or will generate new sources of revenues the more significant of which were our ANR WestLeg Expansion, SNG South System Expansions, TGP South Texas Expansion and CIG Front Range Expansion. Our expansions during this three year period added approximately 1,968 MMcf/d to our overall pipeline system.

Our pipeline systems connect the principal gas supply regions to the largest consuming regions in the U.S. We are well-positioned to capture growth opportunities in the Rocky Mountains and deepwater Gulf of Mexico, and have an infrastructure that complements LNG growth. We are aggressively seeking to attach new supplies of natural gas to our systems in order to maintain an adequate supply of gas to serve our growing markets and to replace quantities lost due to the natural decline in production from wells currently attached to our system.

Expansion projects currently in process include:

Rocky Mountain Expansions. In order to provide an outlet for the growing supply of Rocky Mountain natural gas to markets in the Midwest region of the United States, we have several expansion projects that will increase our transportation capacity, subject to regulatory approval as follows:

- Cheyenne Plains Gas Pipeline commenced free-flow operations in December 2004 and as of January 31, 2005 is fully in-service. Approval has already been received for Cheyenne Plains Phase II which will add an additional 179 MMcf/d of capacity that is scheduled to be available by the end of 2005.

- CIG s Raton Basin 2005 Expansion will add 104 MMcf/d of capacity that is scheduled to be available by the end of 2005.

- WIC expects to complete its Piceance lateral with capacity of 333 MMcf/d by the end of 2005.

- EPNG s Line 1903 project, consisting of an expansion from Cadiz, California to Ehrenberg, Arizona, that is expected to be in-service by end of 2005 and will increase its capacity by 372 MMcf/d.

LNG Related Expansions and Other. In order to help serve the growing electrical generation needs in the state of Florida, we (i) have commenced a 3.5 Bcf expansion at our Elba Island LNG facility, which is targeted to be completed in the first quarter of 2006, (ii) have begun developing our Cypress Project, which will transport these additional supplies into the Florida market.

On our TGP and ANR systems, we continue to experience intense competition along their mainline corridors; however, both are well-positioned to provide transportation service from discoveries in the deepwater Gulf of Mexico and LNG supply growth along the Gulf Coast. These new supplies are expected to offset the continued decline of production from the Gulf of Mexico shelf. Additionally, TGP is developing its

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ConneXion Expansions in the Northeast market area and ANR is proceeding with its East Leg and North Leg expansions in its Wisconsin market area.

Other Regulatory Matters. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $25 million to $41 million annually over the next eight years.

In 2003, we re-applied Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* on our CIG and WIC systems, resulting in income from recording the regulatory assets of these systems. SFAS No. 71 allows a company to capitalize items that will be considered in future rate proceedings and $18 million in income resulted from the capitalization of those items that we believe will be considered in CIG s and WIC s future rate cases. At the same time CIG and WIC re-applied SFAS No. 71, they adopted the FERC depreciation rate for their regulated plant and equipment. This change resulted in an increase in depreciation expense of approximately $9 million in 2004, an increase which will continue in the future. As of December 31, 2004, ANR Storage Company re-applied SFAS No. 71 which had an immaterial impact and also adopted the FERC depreciation rate which will result in future depreciation expense increases of approximately $4 million annually.

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability. Listed below is a status of our rate proceedings:

- SNG filed a rate case in August 2004; settlement discussions with major customers are underway with a settlement conference to be scheduled in early 2005.

- EPNG expected to file for new rates that would be effective January 2006.

- CIG required to file for new rates that would be effective October 2006.

- MPC expected to file for new rates that would be effective February 2007.

Our other pipelines have no requirements to file new rate cases and expect to continue operating under their existing rates.

Australian Impairment. In 2002, our impairment of EPIC Energy Australia Trust of $141 million occurred due to an unfavorable regulatory environment, increased competition and operational complexities in Australia. During the second quarter of 2004, we substantially exited our investments in Australian operations.

Western Energy Settlement. In 2003, El Paso entered into the Western Energy Settlement. EPNG was a party to that settlement and recorded a charge in its 2002 operating expenses of $412 million for its share of the expected settlement amounts. This charge represented the value of El Paso stock and cash that EPNG paid to the settling parties. In the second quarter of 2003, the settlement was finalized and EPNG recorded an additional net pretax charge of $127 million. Also during 2003, accretion expense and other miscellaneous charges of $13 million were recorded and included in operating expenses.

Non-regulated Business Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and minimize our total administrative costs.

Our long-term strategy includes developing our production opportunities primarily in the United States and Brazil, while prudently divesting of production properties outside of these regions. We emphasize strict capital discipline designed to improve capital efficiencies through the use of standardized risk analysis and a

heightened focus on cost control. We also implemented a more rigorous process for booking proved natural gas and oil reserves, which includes multiple layers of reviews by personnel independent of the reserve estimation process. Our plan is to stabilize production by improving the production mix across our operating areas and to generate more predictable returns. We intend to improve our production mix by allocating more capital to long-life, slower decline projects and to develop projects in longer reserve life areas. This is being accomplished through our more rigorous capital review process and a more balanced allocation of our capital to development and exploration projects, supplemented by acquisition activities with low-risk development locations that provide operating synergies with our existing operations. In January 2005, we announced two acquisitions in east Texas and south Texas for $211 million. In March 2005, we acquired the interests held by one of the parties under our net profits interest agreements for $62 million. See Supplemental Financial Information, under the heading Supplemental Natural Gas and Oil Operations (Unaudited) beginning on page F-126, for a further discussion of these net profits interest agreements. These acquisitions added properties with approximately 139 Bcfe of existing proved reserves and 52 MMcfe/d of current production. More importantly, the Texas acquisitions offer additional exploration upside in two of our key operating areas.

Reserves, Production and Costs

Our estimate of proved natural gas and oil reserves as of December 31, 2004 reflects 2.0 Tcfe of proved reserves in the United States and 0.2 Tcfe of proved reserves in Brazil. These estimates were prepared internally by us. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott is within four percent of our internally prepared estimates. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our properties based on value. For additional information on our estimated proved reserves and the processes by which they are developed, see Critical Accounting Policies, page 66, Business Non-regulated Business Production Segment, page 109, Risk Factors, page 7, and Supplemental Financial Information, under the heading Supplemental Natural Gas and Oil Operations (Unaudited), on page F-126.

For 2004, our total equivalent production declined 112 Bcfe or 27 percent as compared to 2003. The decrease was due to steep production declines in our Texas Gulf Coast and offshore Gulf of Mexico regions, the sale of properties in Oklahoma and New Mexico at the end of the first quarter of 2003, and a significantly reduced capital expenditure program in 2004 compared to 2003. We began to see our production stabilize in the third and fourth quarters of 2004 as we instituted our more rigorous capital review process and a more balanced allocation of our capital described above. Our depletion rate is determined under the full cost method of accounting. Due to disappointing drilling performance in 2004 that resulted in higher finding and development costs, we expect our domestic unit of production depletion rate to increase from $1.80/ Mcfe in the fourth quarter of 2004 to $1.97/ Mcfe in the first quarter of 2005. Our future trends in production and depletion rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sale or acquisition activities relating to our proved reserves.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment programs. We conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production. Because this hedging strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. For 2005, we expect to have hedged approximately 50 percent of our anticipated daily natural gas production and

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approximately 8 percent of our anticipated daily oil production. Below are the hedging positions on our anticipated natural gas and oil production as of December 31, 2004:

Natural Gas

	Quarter Ended									
	March 31		June 30		September 30		December 31		Total	
	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)	Volume (BBtu)	Hedged Price (per MMBtu)
2005	33,019	$ 7.26	33,037	$ 6.47	33,055	$ 6.49	33,055	$ 6.77	132,166	$ 6.75
2006	21,349	$ 7.07	21,367	$ 6.01	21,385	$ 6.01	21,385	$ 6.28	85,486	$ 6.34
2007	1,579	$ 3.79	1,447	$ 3.64	1,155	$ 3.35	1,155	$ 3.35	5,336	$ 3.56
2008 through 2012									20,620	$ 3.67

Oil

	Quarter Ended									
	March 31		June 30		September 30		December 31		Total	
	Volume (MBbls)	Hedged Price (per Bbl)	Volume (MBbls)	Hedged Price (per Bbl)	Volume (MBbls)	Hedged Price (per Bbl)	Volume (MBbls)	Hedged Price (per Bbl)	Volume (MBbls)	Hedged Price (per Bbl)
2005	94	$ 35.15	96	$ 35.15	96	$ 35.15	97	$ 35.15	383	$ 35.15
2006	94	$ 35.15	96	$ 35.15	96	$ 35.15	97	$ 35.15	383	$ 35.15
2007	47	$ 35.15	48	$ 35.15	48	$ 35.15	49	$ 35.15	192	$ 35.15

The hedged natural gas prices listed above for 2005 and 2006 include the impact of designating trading contracts in our Marketing and Trading segment as hedges of our anticipated natural gas production on December 1, 2004. For a summary of the overall cash price El Paso will receive on natural gas production including the effect of these contracts, see Management s Discussion and Analysis of Financial Condition and Results of Operations Commodity-based Derivative Contracts beginning on page 29.

Operational Factors Affecting the Year Ended December 31, 2004

During 2004, our Production segment experienced the following:

Higher realized prices. Realized natural gas prices, which include the impact of our hedges, increased eight percent and oil, condensate and NGL prices increased 33 percent compared to 2003.

Average daily production of 814 MMcfe/d (excluding discontinued Canadian and other international operations of 15 MMcfe/d). We achieved the low end of our projected production volume despite the impact of hurricanes in the Gulf of Mexico.

Capital expenditures and acquisitions of $790 million (excluding discontinued Canadian and other international expenditures of $29 million). During the first quarter of 2004, we experienced disappointing drilling results. As a result, we significantly reduced our drilling activities and instituted a new, more rigorous, risk analysis program, with an emphasis on strict capital discipline. After implementing this new program, we increased our domestic drilling activities in the third and fourth quarters of 2004 with improved drilling results. During 2004, we drilled 325 wells with a 96 percent success rate. We also acquired the remaining 50 percent interest in UnoPaso in Brazil in July 2004. This acquisition has performed above expectations in the fourth quarter of 2004.

Sale of Canadian and other international operations. These operations were sold in order to focus our operations in the United States and Brazil.

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Operating Results

Below are our Production segment s operating results and analysis of these results for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
Operating Revenues:			
Natural gas	$ 1,428	$ 1,831	$ 1,574
Oil, condensate and NGL	305	305	350
Other	2	5	7
Total operating revenues	1,735	2,141	1,931
Transportation and net product costs	(54)	(82)	(109)
Total operating margin	1,681	2,059	1,822
Depreciation, depletion and amortization	(548)	(576)	(601)
Production costs(1)	(210)	(229)	(285)
Ceiling test and other charges(2)	(22)	(16)	(4)
General and administrative expenses	(173)	(160)	(122)
Taxes, other than production and income	(2)	(5)	(7)
Total operating expenses(3)	(955)	(986)	(1,019)
Operating income	726	1,073	803
Other income	8	18	5
EBIT	$ 734	$ 1,091	$ 808

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	2004	Percent Variance	2003	Percent Variance	2002
Volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	244,857	(28)%	338,762	(28)%	470,082
Average realized prices including hedges ($/Mcf)[4]	$ 5.83	8%	$ 5.40	61%	$ 3.35
Average realized prices excluding hedges ($/Mcf)[4]	$ 5.90	7%	$ 5.51	74%	$ 3.17
Average transportation costs ($/Mcf)	$ 0.17	(6)%	$ 0.18		$ 0.18
Oil, condensate and NGL					
Volumes (MBbls)	8,818	(25)%	11,778	(28)%	16,462
Average realized prices including hedges ($/Bbl)[4]	$ 34.61	33%	$ 25.96	22%	$ 21.28
Average realized prices excluding hedges ($/Bbl)[4]	$ 34.75	30%	$ 26.64	25%	$ 21.38
Average transportation costs ($/Bbl)	$ 1.12	7%	$ 1.05	8%	$ 0.97
Total equivalent volumes(MMcfe)	297,766	(27)%	409,432	(28)%	568,852
Production costs($/Mcfe)					
Average lease operating costs	$ 0.60	43%	$ 0.42		$ 0.42
Average production taxes	0.11	(21)%	0.14	75%	0.08
Total production cost[1]	$ 0.71	27%	$ 0.56	12%	$ 0.50
Average general and administrative expenses ($/Mcfe)	$ 0.58	49%	$ 0.39	86%	$ 0.21
Unit of production depletion cost ($/Mcfe)	$ 1.69	29%	$ 1.31	28%	$ 1.02

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

(2) Includes ceiling test charges, restructuring charges, asset impairments and gains on asset sales.

(3) Transportation costs are included in operating expenses on our consolidated statements of income.

(4) Prices are stated before transportation costs.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Our EBIT for 2004 decreased $357 million as compared to 2003. Despite an eight percent increase in natural gas prices including hedges, we experienced a significant decrease in operating revenues due to lower production volumes as a result of normal production declines, asset sales, a lower capital spending program

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and disappointing drilling results. The table below lists the significant variances in our operating results in 2004 as compared to 2003:

	Variance			
	Operating Revenue	Operating Expense	Other[1]	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher prices in 2004	$ 96	$	$	$ 96
Lower production volumes in 2004	(518)			(518)
Impact from hedge program in 2004 versus 2003	19			19
Oil, Condensate and NGL Revenue				
Higher realized prices in 2004	72			72
Lower production volumes in 2004	(79)			(79)
Impact from hedge program in 2004 versus 2003	7			7
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2004		(115)		(115)
Lower production volumes in 2004		146		146
Production Costs				
Higher lease operating costs in 2004		(8)		(8)
Lower production taxes in 2004		27		27
Other				
Higher general and administrative expenses in 2004		(13)		(13)
Other	(3)	(6)	18	9
Total variance 2004 to 2003	$ (406)	$ 31	$ 18	$ (357)

[1] Consists primarily of changes in transportation costs and other income.

Operating revenues. In 2004, we experienced a significant decrease in production volumes. The decline in our production volumes was due to normal production declines in the Offshore Gulf of Mexico and Texas Gulf Coast regions, asset sales, the impact of hurricanes in the Gulf of Mexico, lower capital expenditures and disappointing drilling results. These declines were partially offset by increased natural gas production in our coal seam operations in the Raton, Arkoma, and Black Warrior basins. We also had increased oil production in Brazil as a result of our acquisition of the remaining interest in UnoPaso in July 2004. In addition, we experienced higher average realized prices for natural gas and oil, condensate and NGL and a favorable impact from our hedging program as our hedging losses were $18 million in 2004 as compared to $44 million in 2003.

Depreciation, depletion, and amortization expense. Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs.

Production costs. In 2004, we experienced higher workover costs due to the implementation of programs in the second half of 2004 to improve production in the Offshore Gulf of Mexico and Texas Gulf Coast regions. We also incurred higher utility expenses and higher salt water disposal costs in the Onshore region. More than offsetting these increases were lower production taxes as a result of higher tax credits taken in 2004 on high cost natural gas wells.

The cost per unit increased due to the higher lease operating costs and lower production volumes discussed above.

Other. Our general and administrative expenses increased primarily due to higher contract labor costs and lower capitalized costs in 2004. The cost per unit increased due to a combination of higher costs and lower production volumes discussed above.

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Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Our EBIT for 2003 increased $283 million as compared to 2002. For the year ended December 31, 2003, natural gas prices, including hedges, increased 61 percent; however, we also experienced a significant decrease in production volumes as a result of asset sales, normal production declines, mechanical failures in several of our producing wells, a lower capital spending program and disappointing drilling results. The table below lists the significant variances in our operating results in 2003 as compared to 2002:

	Variance			
	Operating Revenue	**Operating Expense**	**Other(1)**	**EBIT Impact**
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2003	$ 792	$	$	$ 792
Lower production volumes in 2003	(416)			(416)
Impact from hedge program in 2003 versus 2002	(119)			(119)
Oil, Condensate and NGL Revenue				
Higher prices in 2003	62			62
Lower production volumes in 2003	(100)			(100)
Impact from hedge program in 2003 versus 2002	(7)			(7)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2003		(116)		(116)
Lower production volumes in 2003		163		163
Higher accretion expense for asset retirement obligations		(23)		(23)
Production Costs				
Lower lease operating costs in 2003		71		71
Higher production taxes in 2003		(15)		(15)
Other				
Ceiling test and other charges		(12)		(12)
Higher general and administrative costs in 2003		(38)		(38)
Other	(2)	3	40	41
Total variance 2003 to 2002	$ 210	$ 33	$ 40	$ 283

(1) Consists primarily of changes in transportation costs and other income.

Operating revenues. During 2003, we experienced a significant decrease in production volumes due to the sale of properties in New Mexico, Oklahoma, Texas, Colorado, Utah, and Offshore Gulf of Mexico, normal production declines, mechanical failures primarily in the Texas Gulf Coast and Offshore Gulf of Mexico regions, a lower capital spending program and disappointing drilling results. In addition, we incurred an unfavorable impact from our hedging program as our hedging losses were $44 million in 2003 as compared to $82 million of hedging gains in 2002. Despite lower production and unfavorable hedging results, revenues were higher due to higher average realized prices for natural gas and oil, condensate and NGL during 2003.

Depreciation, depletion, and amortization expense. Lower volumes in 2003 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs. We also recorded accretion expense related to our liabilities for asset retirement obligations in connection with the adoption of SFAS No. 143 in 2003.

Production costs. In 2003, we experienced lower production costs primarily due to the asset sales discussed above. However, we also incurred higher production taxes in 2003 as a result of higher natural gas and oil prices and larger tax credits taken in 2002 on high cost natural gas wells. Our cost per unit increased due to the higher production taxes and lower production volumes.

Ceiling test and other charges. In 2003, we incurred an impairment charge related to non-full cost pool assets of \$5 million, net of gains on asset sales, non-cash ceiling test charges of \$5 million associated with our operations in Brazil and \$6 million in employee severance costs. In 2002, we incurred a non-cash ceiling test charge of \$3 million associated with our operations in Brazil.

General and administrative expenses. Higher corporate overhead allocations and lower capitalized costs were the main factors leading to the increase in general and administrative expenses in 2003. The cost per unit increased due to a combination of higher costs and lower production volumes discussed above.

Non-regulated Business Marketing and Trading Segment

Our Marketing and Trading segment s operations focus on the marketing of our natural gas and oil production and the management of our remaining trading portfolio. Over the past several years, a number of significant events occurred in this business and in the industry:

2001 and 2002

The deterioration of the energy trading environment followed by our announcement in November 2002 that we would reduce our involvement in the energy marketing and trading business and pursue an orderly liquidation of our trading portfolio.

2003 and 2004

A challenging trading environment with reduced liquidity, lower credit standing of industry participants and a general decline in the number of trading counterparties.

The ongoing liquidation of our historical trading portfolio.

The announcement in December 2003 that we would change our operations to primarily focus on the physical marketing of natural gas and oil produced in our Production segment.

Currently, we do not anticipate that we will liquidate all of the transactions in our trading portfolio before the end of their contract term. We may retain contracts because (i) they are either uneconomical to sell or terminate in the current environment due to their contractual terms or credit concerns of the counterparty, (ii) a sale would require an acceleration of cash demands, or (iii) they represent hedges associated with activities reflected in other segments of our business, including our Production and Power segments. Changes to our liquidation strategy may impact the cash flows and the financial results of this segment.

Our Marketing and Trading segment s portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. The following is a discussion of the significant types of contracts used by our Marketing and Trading segment and how they impact our financial results:

Natural Gas Contracts

Production-related and other natural gas derivatives

Derivatives designated as hedges. We enter into contracts with third parties, primarily fixed for floating swaps, on behalf of our Production segment to hedge its anticipated natural gas production. These natural gas contracts consist of obligations to deliver natural gas at fixed prices. As of December 31, 2004, these contracts effectively hedged a total of 244 TBtu of our anticipated natural gas production through 2012. Of this total amount, 84 percent of these contracts were designated as accounting hedges on December 1, 2004. All contracts that are designated as hedges of our Production segment s natural gas and oil production are accounted for in the operating results of that segment.

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Production-related options. These contracts, which are marked to market in our results each period, and are not accounting hedges, provide price protection to El Paso from natural gas price declines related to our natural gas production in 2005 and 2006. Entered into in the fourth quarter of 2004, these contracts will allow El Paso to achieve a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006.

In the first quarter of 2005, we entered into additional contracts that provide El Paso with a floor price of $6.00 per MMBtu on 30 TBtu of our natural gas production in 2007, and also capped us at a ceiling price of $9.50 per MMBtu on 60 TBtu of our natural gas production in 2006.

Other natural gas derivatives. Other natural gas derivatives consist of physical and financial natural gas contracts that impact our earnings as the fair values of these contracts change. These contracts obligate us to either purchase or sell natural gas at fixed prices. Our exposure to natural gas price changes will vary from period to period based on whether, overall, we purchase more or less natural gas than we sell under these contracts.

Transportation-related contracts

Our transportation contracts provide us with approximately 1.5 Bcf of pipeline capacity per day, for which we are charged approximately $149 million in annual demand charges. These contracts are accrual-based contracts that impact our gross margin as delivery or service under the contracts occurs. The following table details our transportation contracts:

	Alliance	**Texas Intrastate**	**Other**
Daily capacity (MMBtu/day)	160,000	435,000	910,000
Annual demand charges (in millions)	$66	$21	$62
Expiration	2015	2006	2005 to 2028
Receipt points	AECO Canada	South Texas	Various
Delivery points	Chicago	Houston Ship Channel	Various

Historically, these contracts have resulted in significant losses to El Paso. The extent of these losses is dependent upon our ability to utilize the contracted pipeline capacity, which is impacted by:

The difference in natural gas prices at contractual receipt and delivery locations;

The capital needed to use this capacity (i.e. cash margins or letters of credit associated with the purchase and sale of natural gas to use the capacity); and

The capacity required to meet our other long term obligations.

Storage contracts

During 2003, we eliminated a significant portion of our natural gas storage capacity contracts through the ongoing liquidation of our trading portfolio. We retained storage capacity of 4.7 Bcf at TGP s Bear Creek Storage Field and Enterprise Products Partners Wilson storage facilities for operational and balancing purposes. We do not anticipate that our retained storage contracts will significantly impact our earnings in the future.

Power Contracts

Tolling contracts. We have two tolling contracts under which we supply fuel to power plants and receive the power generated by these plants. In exchange for this right to the power generated, we pay a demand charge. Our ability to recover these demand charges is primarily dependent upon the difference between the cost of fuel we supply to the plant and the value of the power we receive from the plant under the contract. Our tolling contracts are derivatives that impact our earnings as their fair value changes each period.

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Our largest tolling contract provides us with approximately 548 MW of generating capacity at the Cordova power plant through 2019, for which we are charged $27 million to $32 million in annual demand charges. In addition, the Cordova power plant has the option to repurchase up to 50 percent of this generating capacity from us. We have historically experienced significant volatility in the fair value of this tolling contract, primarily due to changes in natural gas and power prices in the market that Cordova serves. We expect this volatility to continue. Our other tolling contract provides us with approximately 257 MW of generating capacity in the Alberta power pool through the third quarter of 2005, for which we expect to be charged $14 million of demand charges in 2005.

Contracts related to power restructuring activities. These contracts consist of long-term obligations to provide power for the restructured power contracts in our Power segment. With the sale of substantially all of our restructured power contracts, we have or are in the process of eliminating substantially all of these obligations, with the exception of our contract with Morgan Stanley related to UCF. This contract, which calls for us to deliver of up to 1,700 MMWh per year through 2016 at a fixed price, may continue to impact our earnings in the future.

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Operating Results

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for each of the three years ended December 31. Because of the substantial changes in the composition of our portfolio, year-to-year comparability was affected:

	2004 (Restated)	2003	2002
		(In millions)	
Overall EBIT:			
Gross margin[1]	$ (508)	$ (636)	$ (1,316)
Operating expenses	(54)	(183)	(677)
Operating loss	(562)	(819)	(1,993)
Other income	23	10	16
EBIT	$ (539)	$ (809)	$ (1,977)
Gross Margin by Significant Contract Type:			
Natural Gas Contracts			
Production-related and other natural gas derivatives			
Changes in fair value on positions designated as hedges on December 1, 2004	$ (439)	$ (425)	$ (601)
Changes in fair value on production-related options	53		
Changes in fair value on other natural gas positions	44	2	(486)
Early contract terminations	48	(8)	
Total production-related and other natural gas derivatives	(294)	(431)	(1,087)
Transportation-related contracts			
Demand charges	(149)	(156)	(36)
Settlements	39	4	16
Total transportation-related contracts	(110)	(152)	(20)
Storage contracts			
Demand charges	(2)	(21)	(15)
Settlements		31	56
Early contract terminations		(17)	
Total storage contracts	(2)	(7)	41
Total gross margin natural gas contracts	(406)	(590)	(1,066)
Power Contracts			
Changes in fair value on Cordova tolling agreement	(36)	75	(112)
Other power derivatives			
Changes in fair value	(85)	(96)	(138)
Early contract terminations	19	(25)	
Total other power derivatives	(66)	(121)	(138)

Total gross margin power contracts	(102)	(46)	(250)
Total gross margin	$ (508)	$ (636)	$ (1,316)

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

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Overall, during 2004, 2003 and 2002, we experienced substantial losses in gross margin on our trading contracts due to a number of factors. In 2002, we experienced losses in our natural gas and power contracts as a result of general market declines in energy trading resulting from lower price volatility in the natural gas and power markets and a generally weaker trading and credit environment. Also contributing to the deterioration of the market valuations of our trading and marketing assets was the announcement in the fourth quarter of 2002 by many participants in the trading industry, including us, to discontinue or significantly reduce trading operations. Following this announcement, we liquidated a number of positions earlier than their scheduled maturity, which caused us to incur additional losses in gross margin in 2002 and 2003 than had we held those contracts to maturity. We also experienced difficulty in 2002 and 2003 in collecting on several claims from various industry participants experiencing financial difficulty, several of whom sought bankruptcy protection. Any settlements under ongoing proceedings in these matters could impact our future financial results.

Listed below is a discussion of other factors, by significant contract type, that affected the profitability of our Marketing and Trading segment during each of the three years ended December 31, 2004:

Natural Gas Contracts

Production-related and other natural gas derivatives

Derivatives designated as hedges. The amounts in the above table represent changes in the fair values of derivative contracts that were designated as accounting hedges of our Production segment s natural gas production on December 1, 2004. The losses indicated were a result of increases in natural gas prices in 2002, 2003 and 2004 relative to the fixed prices in these contracts and these losses were historically included in our financial results. Following their designation as accounting hedges, future income impacts of these contracts will be reflected in our Production segment. However, the act of designating these contracts as hedges will have no impact on El Paso s overall cash flows in any period.

Production-related options. As natural gas prices decreased in the fourth quarter of 2004, the fair value of the options we entered into in 2004 increased. These contracts had a fair value of $120 million as of December 31, 2004, which includes the premium we initially paid for the options. If gas prices remain above the option price of $6.00 per MMBtu, the fair value of these contracts will decrease over their term since they would expire unexercised. We paid a total net premium of $64 million for these options and the additional option contracts we entered into in the first quarter of 2005.

Other natural gas derivatives. Because we were obligated to purchase more natural gas at a fixed price than we sold under these contracts during 2003 and 2004, the fair value of these contracts increased as natural gas prices increased during those years. In 2002, we incurred significant losses on these contracts because of lower price volatility and the deterioration of the energy trading environment described above.

Early contract terminations. This amount includes a $50 million gain recognized on the termination of an LNG contract at the Elba Island facility in 2004.

Transportation-related contracts

In the fourth quarter of 2002, we began accounting for our transportation contracts as accrual-based contracts with the adoption of EITF Issue No. 02-3. As a result, our 2002 results include the demand charges and accrual settlements we recorded during the fourth quarter of 2002. The mark-to-market losses on these contracts during the first nine months of 2002 are included in the change in fair value of our other natural gas derivatives above. Our annual demand charges on these contracts were approximately $149 million in 2004 and $156 million in 2003. The decrease in 2004 was due to the liquidation of a number of these positions prior to their original settlement dates.

Our ability to use our Alliance pipeline capacity contract was relatively consistent during 2003 and 2004, allowing us to recover approximately 73 percent of the demand charges we paid each year. This resulted from the price differentials between the receipt and delivery points staying relatively consistent during these years, which resulted in EBIT losses from this contract of $15 million in 2003 and $17 million during 2004. Our Texas Intrastate transportation contracts incurred EBIT losses of $36 million in 2003 and $26 million in 2004. We were unable to utilize a significant portion of the capacity on these pipelines primarily due to a decrease in the price differentials between South Texas receipt points and Houston Ship Channel delivery locations under the contracts. If the differences in these prices do not improve, we will continue to experience losses on these contracts.

Storage contracts

In the fourth quarter of 2002, we began accounting for our storage contracts as accrual-based contracts with the adoption of EITF Issue No. 02-3. As a result, our 2002 results include the demand charges and accrual settlements we recorded during the fourth quarter of 2002. The mark-to-market losses on these contracts during the first nine months of 2002 are included in the change in fair value of our other natural gas derivatives. Our annual demand charges on these contracts were approximately $2 million in 2004 and $21 million in 2003. In 2002 and 2003, we terminated a significant number of our storage positions and recognized a $56 million gain in 2002 and a $31 million gain in 2003 on the withdrawal and sale of the gas held in these storage locations. Based on our actions, our remaining contracts with the Wilson and Bear Creek storage facilities should not have a significant impact on the future financial results of this segment.

Power Contracts

Cordova tolling agreement

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. In 2003, forecasted power prices increased relative to natural gas prices, resulting in a significant increase in the fair value of this contract. In 2004, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract. Additionally, although the Cordova power plant historically sold its power into a relatively illiquid power market in the Midwest, this power market was incorporated into the more liquid Pennsylvania-New Jersey-Maryland power pool in 2004. We believe that this change will reduce the volatility of the fair value of the contract in the future.

Other power derivatives

Historically, many of our contract origination activities related to power contracts. Because of the changes in the energy trading environment and the change in focus of our Marketing and Trading segment, these activities substantially decreased from 2002 to 2004.

The ongoing liquidation of our trading book significantly impacted our power contracts. We also recorded a $25 million gain on the termination of a power contract with our Power segment in 2004, which was eliminated in El Paso s consolidated results.

In the first quarter of 2005, we assigned our contracts to supply power to our Power segment s Cedar Brakes I and II entities to Constellation Energy Commodities Group, Inc. We recorded a loss of approximately $30 million during the fourth quarter of 2004 upon signing the assignment and

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termination agreement. These contracts decreased in fair value by $64 million, $67 million and $48 million in 2004, 2003 and 2002.

In the first quarter of 2002, we recorded an $80 million gain related to a power supply agreement that we entered into with our Power segment. The gain, which was associated with the UCF restructured power contract, was eliminated from El Paso s consolidated results. Later in 2002, we terminated this contract and entered into a new power supply agreement with Morgan Stanley related to UCF. The Morgan Stanley contract decreased in fair value by $72 million, $77 million and $58 million in 2004, 2003 and 2002.

Our remaining power contracts, which include those that are used to manage the risk associated with our obligations to supply power, increased in fair value by $81 million in 2004 and $48 million in 2003.

Operating Expenses

Operating expenses in our Marketing and Trading segment decreased significantly each year due primarily to the following:

In 2002 and 2003, we recorded $487 million and $26 million of charges in operating expenses related to the Western Energy Settlement. In late 2003, this obligation was transferred to our corporate operations.

In 2003 and 2004, we recorded $28 million and $10 million of bad debt expense associated with a fuel supply agreement we have with the Berkshire power plant.

As a result of the decision in November 2002 to reduce the size of our trading portfolio, we experienced a significant decline in employee headcount, which resulted in lower general and administrative expenses in 2003. This decline in headcount, coupled with the closing of our London office in 2003, contributed to further decreases in general and administrative expenses in 2004.

Overall cost reduction efforts at the corporate level and our reduced level of operations resulted in lower corporate overhead being allocated to us in 2003 and 2004.

Non-regulated Business Power Segment

As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also included domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses. Our ongoing focus within the power segment will be to maximize the value of our assets in Brazil. We have designated our other international power operations as non-core activities, and expect to exit these activities in the future as market conditions warrant.

International Power Plant Operations

Brazil. As of December 31, 2004, our Brazilian operations include our Macae, Porto Velho, Manaus, Rio Negro, and Araucaria power plants and our investments in the Bolivia to Brazil and Argentina to Chile pipelines.

Macae. Our Macae power plant sells a majority of its power to the wholesale Brazilian power market. Macae also has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras did not pay amounts due under the contract for December 2004 and January 2005 and filed a lawsuit and for arbitration. For a further discussion of this matter, see Notes to Consolidated Financial Statements, Note 17, on page F-89. The future financial performance of the Macae plant will be affected by the outcome of this dispute and by regional changes in power markets.

Porto Velho. Our Porto Velho plant sells power to Eletronorte under two power sales agreements that expire in 2010 and 2023. Eletronorte absorbs substantially all of the plant s fuel costs and purchases all of the power the plant is able to generate, as long as the plant operates within availability levels required by these contracts. As a result, the profitability of the plant is dependent primarily on maintaining these availability levels through efficient operations and maintenance practices. These availability levels are expected to decrease in 2005 because of an equipment failure at the plant during 2004 that is expected to be repaired by the first quarter of 2006. In addition, we are negotiating potential contractual amendments with Eletronorte that may alter the volumes and prices of power to be sold under the contracts and may affect our future earnings. For a further discussion of these negotiations, see Notes to Consolidated Financial Statements, Note 17, on page F-89.

Manaus and Rio Negro. In January 2005, we signed new power sales contracts for our Manaus and Rio Negro power plants with Manaus Energia. Under these new contracts, Manaus Energia will pay a price for its power that is similar to that in the previous contracts. In addition, Manaus Energia will assume ownership of the Manaus and Rio Negro plants in 2008. Based on this ownership transfer and the contract terms, we will deconsolidate the plants in the first quarter of 2005 and begin to account for them as equity investments. In addition, the earnings from these assets will decrease as a result of the new contracts.

Other. The power sales contract of the Araucaria power plant is currently in international arbitration due to non-payment by the utility that purchases power from the plant. As a result, Araucaria ceased its operations in 2003. For a further discussion of these arbitration proceedings, see Notes to Consolidated Financial Statements, Note 17, on page F-89.

Our two pipelines began operations in 2003 and generate income through the transportation of natural gas to various customers in South America.

Asia. Our Asian operations include interests in 15 power plants, 13 of which are equity investments. These facilities sell electricity and electrical generating capacity under long-term power sales agreements with local transmission and distribution companies, many of which are government controlled. The majority of these contracts allow for changes in fuel costs to be passed through to the customer through power prices. The economic performance of these facilities is impacted by the level of electricity demand and changes in the political and regulatory environment in the countries they serve as well as the relative cost of producing that power. We recorded an impairment of these assets in 2004 in connection with our decision to sell these assets.

Other International. We have interests in 10 power facilities located in South and Central America and Europe, most of which are equity investments. These facilities sell electricity and electrical generating capacity under long-term and short-term power sales agreements with local transmission and distribution companies as well as to the local spot markets. The economic performance of these facilities is impacted by fuel prices, the level of demand for electricity, the level of competition from other power generators, changes in the political and regulatory environment in the countries they serve, and the relative cost of producing power. The performance of our facilities in Central America is also affected by variances in the level of rainfall in the region. As the level of rainfall increases, the level of generation from hydroelectric plants increases which can negatively impact power pricing in the spot market. We have recently announced that we are considering the sale of a number of these assets, although at this time we have not actively marketed them. As this process progresses we will continue to assess the value of these assets which may result in impairments.

Domestic Power Plant Operations

Our domestic operations as of December 31, 2004, primarily consist of an equity ownership in a natural gas-fired power plant, Midland Cogeneration Venture (MCV). The price of electricity sold by MCV is indexed to coal, while the plant is fueled by natural gas, which it purchases under both long-term contracts and on the spot market. Changes in the relationship between coal and natural gas prices directly impact the economic performance of this facility. In 2004, we recorded an impairment of our interest in this plant based on a decline in the value of the investment that we considered to be other than temporary.

During 2004 and the first quarter of 2005, we sold our interests in 33 domestic power plants. With these sales, we incurred substantial impairments in 2003 and 2004. As a result of these sales, we will have substantially lower earnings in our Power segment.

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Domestic Power Contract Restructuring Business

In 2002 and 2003, we maintained or completed several contract restructuring transactions, the largest of which was UCF. During 2004, we completed the sale of UCF and its related restructured power contract, and entered into an agreement to sell our ownership in Cedar Brakes I and II, and their related restructured power contracts. As of December 31, 2004, we held an interest in Mohawk River Funding II and Cedar Brakes I and II. We completed the sale of Cedar Brakes I and II in the first quarter of 2005 and are evaluating potential buyers for Mohawk River Funding II.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for each of the three years ended December 31. Substantial changes in the business during these periods affected year-to-year comparability.

	2004 (Restated)	2003	2002
		(In millions)	
Overall EBIT:			
Gross margin[1]	$ 643	$ 865	$ 1,103
Operating expenses			
Loss on long-lived assets	(599)	(185)	(160)
Other operating expenses	(468)	(693)	(591)
Operating income (loss)	(424)	(13)	352
Earnings from unconsolidated affiliates			
Impairments and net losses on sale	(395)	(347)	(426)
Equity in earnings	146	256	170
Other income (expense)	74	76	(84)
EBIT	$ (599)	$ (28)	$ 12
EBIT by Area:			
International power			
Brazilian operations	$ 52	$ 177	$ 78
Asian operations	(148)	49	(3)
Other	7	70	(243)
	(89)	296	(168)
Domestic power plant operations			
MCV	(171)	29	28
Sold or sale announced	(58)	(400)	55
Other		(12)	(3)
	(229)	(383)	80
Domestic power contract restructuring activities	(228)	150	341
Power turbine impairments	(1)	(33)	(162)
Other[2]	(52)	(58)	(79)

EBIT	$ (599)	$ (28)	$ 12

(1) Gross margin for our Power segment consists of revenues from our power plants and the initial net gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of those contracts. The cost of fuel used in the power generation process is included in operating expenses.

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(2) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance, and engineering costs. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations.

International Power. The following table shows significant factors impacting EBIT in our international power business in 2004, 2003 and 2002:

	2004 (Restated)	2003	2002
		(In millions)	
Brazil			
Earnings from consolidated and unconsolidated plant operations	$ 235	$ 177	$ 97
Manaus and Rio Negro impairment	(183)		
Contract termination fee			(19)
Total Brazil	52	177	78
Asia			
Earnings from consolidated and unconsolidated plant operations	61	49	45
Asian asset impairments	(212)		
PPN impairment			(41)
Meizhou Wan impairment			(7)
Other	3		
Total Asia	(148)	49	(3)
Other International Power			
Earnings from consolidated and unconsolidated plant operations	24	42	102
Argentina gain on sale (impairment)		28	(342)
Other impairments	(3)		(3)
Other	(14)		
Total Other	7	70	(243)
Total	$ (89)	$ 296	$ (168)

Brazil. During 2002 and 2003, we completed the construction of several power plants and pipelines, which allowed them to reach full operational capacity. However, our financial results during each of the three years ended December 31, 2004 were impacted significantly by regional economic and political conditions, which affected the renegotiation of several of the power contracts for our Brazilian power plants. Below is a discussion of each of our significant assets in Brazil.

Macae and Porto Velho

Through the first quarter of 2003, we conducted a majority of our power plant operations in Brazil through Gemstone, an unconsolidated joint venture. In April 2003, we acquired the joint venture partner s interest in Gemstone and began consolidating Gemstone s debt and its interests in the Macae and Porto Velho power plants. As a result, our operating results for 2002 and the first quarter of 2003 include the equity earnings we earned from Gemstone, while our consolidated operating results for all other periods in 2003 and 2004 include the revenues, expenses and equity earnings from Gemstone s assets.

The EBIT we earned from our Macae plant s operations was $172 million, $156 million, and $136 million in 2004, 2003, and 2002. The increase in 2003 was primarily due to Macae reaching full operational capacity in the third quarter of 2002. In addition, the consolidation of Gemstone described above improved our EBIT in 2003 and 2004 since the interest and taxes incurred by Gemstone were no longer included in EBIT.

The EBIT we earned from our Porto Velho plant s operations was $28 million, $28 million and $23 million in 2004, 2003, and 2002. The increase in 2003 was primarily due to Porto Velho reaching full

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operational capacity in mid-2003. In the fourth quarter of 2004, our Porto Velho plant experienced an equipment failure that is expected to temporarily reduce the output of the plant by approximately 30 percent. This equipment failure is expected to be repaired by the first quarter of 2006.

Our combined net exposure on the Macae and Porto Velho plants was approximately $0.8 billion at December 31, 2004. We are currently in negotiations over the Porto Velho contracts with Eletronorte and in a dispute with Petrobras over the Macae contract. As these negotiations and disputes progress, it is possible that impairments of these assets may occur, and these impairments may be significant. For a further discussion of these negotiations and disputes, see Notes to Consolidated Financial Statements, Note 17, on page F-89.

Manaus and Rio Negro

In 2003, we began negotiating the extension of the Manaus and Rio Negro power contracts, which were to expire in 2005 and 2006. Based on the status of our negotiations to extend the contracts, which was negatively impacted by changes in the Brazilian political environment in 2004, we recorded a $183 million impairment of our investment in Manaus and Rio Negro in 2004. We completed an extension of these contracts during the first quarter of 2005. The Manaus and Rio Negro plants had earnings from plant operations of $30 million in 2004, $12 million in 2003 and $18 million in 2002.

South American Pipelines

The EBIT for our Brazilian operations includes EBIT earned by our Bolivia to Brazil and Argentina to Chile pipelines. This amount was $28 million in 2004 and $18 million in 2003. Our EBIT earned by these pipelines was not significant in 2002. Increases during the three year period were primarily due to the Bolivia to Brazil pipeline reaching full operational capacity in the third quarter of 2003.

Asia. During the fourth quarter of 2004, we recorded a $212 million charge on our Asian power assets in connection with our decision to pursue the sale of these assets. These impairment amounts were based on our estimates of the fair value of these projects. In 2005, we engaged a financial advisor to assist us in the sale of these assets. In the first quarter of 2005, we sold our investment in the PPN power facility in India for $20 million. We had impaired this plant in 2002 primarily because of regional political and economic events at that time. As the sales process continues, we will continue to update the fair value of our Asian assets, which may result in further impairments.

From 2002 to 2004, earnings from our Asian power assets were relatively stable as the underlying plants maintained steady levels of availability and production. Higher fuel costs during these periods did not materially impact these plants operations as substantially all of the higher fuel costs were passed through to the power purchasers through higher contracted power prices.

However, during this three year period, several other significant events occurred that improved our financial performance from these assets, including:

- The conversion of two of our Chinese power plants from heavy fuel oil to natural gas, which lowered the production costs at these facilities;
- The issuance of debt at our Meizhou Wan plant in 2004, which reduced liquidity concerns about the plant s operation. This plant had been partially impaired in 2002 based on those concerns;
- The favorable completion of negotiations with Philippine regulators on fuel and power prices at our East Asia plants; and
- The closing of our Singapore office in 2002, which lowered operating expenses.

Other International. The earnings from our other international operations have decreased from 2002 to 2004 due primarily to economic difficulties in some of the countries that we serve as well as specific transactions that affected the profitability of the underlying plants. Major factors contributing to the decreases were:

Dominican Republic. An economic crisis in the Dominican Republic during 2002 and 2003 significantly reduced the amount of power generated and impacted our ability to collect some of the receivables at our power plants in the country during 2003 and 2004. The Dominican Republic s economy began to improve in late 2004 following the election of a new president. See Notes to Consolidated Financial Statements, Note 22, on page F-110 for a further discussion of our investments in the Dominican Republic.

El Salvador. In 2002, we restructured a power contract at our El Salvador power facility, which resulted in a $77 million gain in 2002. This restructuring converted the plant to a merchant facility that sells power under short-term contracts and on the open market. As a result, the power and resulting earnings generated by this plant in 2002 were higher than in 2003 and 2004.

Argentina. In 2002, we impaired our investment in Argentina based on new legislation resulting from an economic crisis in Argentina. We sold these plants in 2003 and are attempting to recover a portion of these losses through international arbitration.

Other. Our other international operations are also sensitive to changes in the local demand for power and the cost of fuel to run the power facilities. Our power plant in England benefited from increases in demand and power prices in 2004, but this was largely offset by higher fuel prices at our Central American power plants.

As part of our long term business strategy, we are considering the sale of a number of our other international power assets. As these sales occur and/or as market indicators of fair value become available, it is possible that impairments of these assets may occur, and these impairments may be significant.

Domestic Power. The following table shows significant factors impacting EBIT within our domestic power business in 2004, 2003, and 2002:

	2004	2003	2002
		(In millions)	
MCV			
Earnings from plant operations	$ (10)	$ 29	$ 28
Impairments	(161)		
Assets sold or expected to be sold in 2005			
Earnings from consolidated and unconsolidated plant operations[1]	47	103	144
Impairments and write-offs	(105)	(503)	(89)
Other		(12)	(3)
Total	$ (229)	$ (383)	$ 80

[1] During 2004 and 2003, we recorded $60 million and $105 million of operating income generated by the power plants from Chaparral, an equity investment we consolidated effective January 1, 2003. Prior to January 2003, we recorded our earnings from the Chaparral power plants through the equity earnings and management fees we received which were approximately $124 million in 2002.

MCV. Our MCV power plant is a natural gas-fired plant, which sells its power at a contracted price that is indexed to coal prices. During 2004, MCV experienced reduced EBIT primarily because natural gas prices increased at a faster rate than coal prices. This decrease in EBIT was magnified by an increase in the volume of power MCV was required to generate. In January 2005, MCV received regulatory approval to reduce the required level of power generation. In the fourth quarter of 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

Assets sold or to be sold in 2005. During the three years ended December 31, 2004, we recorded significant impairments in our domestic power business as discussed below.

In 2004, 2003, and 2002, we incurred approximately $105 million, $208 million and $89 million of asset impairments, net of realized gains and losses, in our domestic power business based on the anticipated sale of these assets as well as operational and contractual issues at several of these facilities. During 2004, these amounts included $81 million related to impairing the earnings of assets held for sale, in addition to $24 million of impairments, net of gains and losses, on long-lived assets related to our held for sale merchant and contracted plants. We also incurred a $25 million loss on the termination of a power contract with our Marketing and Trading segment related to one of the assets sold, which is reflected in our 2004 earnings from plant operations.

In 2003, we also:

Recorded an impairment of our Chaparral investment of $207 million based on a decline in the investment s value that was considered to be other than temporary. See Notes to Consolidated Financial Statements, Notes 2 and 3, on pages F-58 to F-62, and Note 22, on page F-110, for further discussion of these matters.

Wrote-off a receivable of $88 million from Milford Power LLC related to the transfer of our interest in Milford Power LLC to its lenders after continued difficulties with this facility.

Domestic Power Contract Restructuring. The following table shows significant factors impacting EBIT within our domestic power contract restructuring activities in 2004, 2003 and 2002:

	2004	2003	2002
		(In millions)	
Restructuring gain	$	$	$ 331
Impairments and gains (losses) on sale			
UCF	(99)		
Cedar Brakes I and II	(227)		
Other		(15)	
Change in fair value of contracts			
UCF, Cedar Brakes I and II	97	119	9
MRF II	4	10	
Other	(2)	15	
Other	(1)	21	1
EBIT	$ (228)	$ 150	$ 341

In 2002, we restructured several above-market, long-term power sales contracts with regulated utilities that were originally tied to older power plants. These contracts were amended so that the power sold to the utilities was not required to be delivered from the specified power generation plant, but could be obtained in the wholesale power market. As a result of our credit rating downgrades and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and are exiting such activities which will reduce our EBIT in future periods. For a further discussion of our power restructuring activities, see below and Notes to Consolidated Financial Statements, Note 10, on page F-73.

Restructuring Gain. During 2002, we restructured the power sales contracts at our Eagle Point power facility (also known as UCF) and our Mount Carmel power plant, which resulted in combined net gains of $501 million (net of minority interest.) Prior to restructuring the contracts, the power plants power purchase contracts were accounted for using accrual accounting. Following the restructuring, the power purchase agreements were accounted for as derivatives and recorded at fair value, resulting in a net gain on the date the contracts were restructured. In conjunction with the UCF restructuring in 2002, we paid a $90 million contract termination fee to terminate a steam contract between our Eagle Point power plant and the Eagle Point refinery and we recorded an $80 million loss on a power supply agreement that we entered into with our Marketing and Trading segment. The $90 million and $80 million losses eliminated in El Paso s consolidated results.

Sale of UCF/ Cedar Brakes I and II. During 2004, we sold UCF and in March 2005 we sold Cedar Brakes I and II. These sales resulted in impairments on the Cedar Brakes I and II entities and on UCF in 2004.

Non-regulated Business Field Services Segment

Our Field Services segment conducts our remaining midstream activities, which primarily include gathering and processing assets in south Louisiana. During 2002, 2003 and 2004, we held significant general and limited partner interests in GulfTerra and Enterprise. From December 2003 to January 2005, we sold all of our general and limited partner interests in GulfTerra and Enterprise, our South Texas processing plants, and our interests in the Indian Springs natural gas gathering and processing assets to Enterprise in a series of transactions described further in Notes to Consolidated Financial Statements, Note 22, on page F-110.

During 2003 and 2004, the primary source of earnings in our Field Services segment was from our interests in GulfTerra and Enterprise. On the sale of our interests in GulfTerra in 2003 and 2004, we recognized significant gains, as well as a goodwill impairment of $480 million. Prior to the sale of our interests in GulfTerra, we also received management fees under an agreement to provide operational and administrative services to the partnership. In addition, we received reimbursements for costs paid directly by us on GulfTerra s behalf. For the twelve months ended December 31, 2004, 2003, and 2002, we received approximately $71 million, $91 million, and $60 million in management fees and cost reimbursements. As a result of the sale of our general and limited partnership interests in September 2004, we no longer receive management fees and, as the result of the sale of our remaining interest in January 2005, we will no longer recognize equity earnings related to these investments.

Our significant remaining obligations to Enterprise are to provide an estimated $45 million in payments to Enterprise during the next three years and provide for the reimbursement of a portion of Enterprise s future pipeline integrity costs related to assets sold by us to GulfTerra in 2002 for which we recorded a $74 million liability in 2003. As a result of regulatory changes relating to pipeline integrity and subsequent negotiations with Enterprise, we reduced our estimated obligation to Enterprise by approximately $9 million during the fourth quarter of 2004. In addition, we are to provide for the reimbursement of a portion of GulfTerra s maintenance expenses on certain previously sold assets for which we recorded an estimated liability and a charge to operating expenses of $8 million in 2004. For further discussion of these indemnification agreements, see Notes to Consolidated Financial Statements, Note 17, on page F-89.

During 2004, our earnings and cash distributions received from GulfTerra and Enterprise were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner s share of distributions	$ 65	$ 67
Proportionate share of income available to common unit holders	16	26
Series C units	14	24
Gain on issuance by GulfTerra of its common units	5	
	$ 100	$ 117

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Below are the operating results and analysis of the results for our Field Services segment for each of the three years ended December 31:

	2004	2003	2002
Gathering and processing gross margins(1)	$ 165	$ 132	$ 349
Operating expenses			
Gain (loss) on long-lived assets	(508)	(173)	179
Other operating expenses	(122)	(152)	(255)
Operating income (loss)	(465)	(193)	273
Other income			
Gain (loss) on unconsolidated affiliates	501	181	(50)
Other income	84	145	66
EBIT	$ 120	$ 133	$ 289
Volumes and Prices:			
Gathering			
Volumes (BBtu/d)	203	357	3,023
Prices ($/MMBtu)	$ 0.10	$ 0.18	$ 0.17
Processing			
Volumes (BBtu/d)	2,780	3,206	3,920
Prices ($/MMBtu)	$ 0.14	$ 0.10	$ 0.10

(1) Gross margins consist of operating revenues less cost of products sold. We believe that this measurement is more meaningful for understanding and analyzing our Field Services segment s operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

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Below is a summary of significant factors and related discussions affecting EBIT for each of the three years ended December 31:

	2004	2003	2002
Gathering and Processing Activities			
Gathering and processing margins	$ 165	$ 132	$ 349
Operating expenses	(122)	(152)	(255)
Other	10	(7)	(53)
	53	(27)	41
GulfTerra/ Enterprise Related Items			
Sale of assets to GulfTerra			
San Juan, Texas, and New Mexico assets			210
Release of Chaco lease obligation		67	
Pipeline integrity indemnification	9	(74)	
Sale of assets/interests to Enterprise			
Gain on sale of GP/ LP interests	507	266	
Minority interest	(32)		
South Texas	(11)	(167)	
Indian Springs	(13)		
Goodwill impairment	(480)		
Equity earnings	100	153	69
	80	245	279
Other Asset Sales			
Asset impairments and gains (losses) on sales			
North Louisiana			(66)
Dauphin Island/ Mobile Bay		(86)	
Other	(13)	1	35
	(13)	(85)	(31)
EBIT	$ 120	$ 133	$ 289

Gathering and Processing Activities. During the three years ended December 31, 2004, we have experienced a decrease in our gross margin with a corresponding decrease in our operation and maintenance expenses primarily as a result of asset sales. Additionally, our gathering and processing margins during these periods have been impacted by the spread between NGL prices and natural gas prices. As these spreads increase, we generally increase the NGL volumes we extract, which affects our margin. In 2003, our margins were negatively impacted by a decrease in these spreads as natural gas prices relative to NGL prices increased, which also caused us to reduce the amount of NGL extracted as compared to 2002. However, in 2004 these margins were positively impacted by an increase in these spreads as NGL prices recovered, which also caused us to increase the amount of NGL extracted by our natural gas processing facilities in south Texas. In addition, our margin attributable to the marketing of NGL increased in 2004 as a result of lower fuel and transportation costs. In the future, the margins for our remaining assets will remain sensitive to the spread between natural gas pricing and NGL pricing.

GulfTerra/ Enterprise Related Items. During 2002 and 2003, we sold a substantial amount of our assets to GulfTerra which decreased our gross margin and operating expenses, while at the same time increasing our equity earnings from our general and limited partner interests in GulfTerra. Listed below are the significant transactions with GulfTerra:

2002 the gain on our sale of our Texas and New Mexico gathering and pipeline assets and our San Juan gathering assets.

2003 the release from our Chaco lease obligation in return for communication assets and clarification of our obligation to provide for pipeline integrity costs through 2006.

From December 2003 to January 2005, we entered into a series of transactions with Enterprise in which we sold all of our interests in GulfTerra. In December 2003, we sold 50 percent of our interest in GulfTerra to Enterprise and recorded a gain on the sale in other income. At the same time, we recorded an impairment of our south Texas assets in operating expenses based on the planned sale of these assets to Enterprise in 2004. In September 2004, we completed the sale of our remaining 50 percent interest in the general partner of GulfTerra to Enterprise and recorded a gain on the sale in other income. As a result of the substantial reduction in our asset base primarily from these sales to Enterprise, we recorded an impairment in operating expenses for the entire amount of goodwill upon determination that the goodwill in this segment was no longer recoverable. Finally, at the end of 2004, we entered into negotiations to sell our Indian Springs assets to Enterprise and recorded an impairment charge in operating expenses on these assets based on their planned sale in 2005. We completed the sale of the Indian Springs assets in January 2005. We also sold our remaining general and limited partnership interests in Enterprise for $425 million in January 2005.

Other Asset Sales. In 2002, we recorded an impairment in operating expenses for our north Louisiana assets based on their planned sale, which was completed in 2003. In 2003, we recorded an impairment in other income of our investment in our Dauphin Island Gathering system and Mobile Bay Processing plant based on the planned sale of these investments. We sold these investments in August 2004.

Corporate and Other Expenses, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business, petroleum ship charter operations and various other contracts and assets, including financial services and LNG and related items, all of which are immaterial to our results. The following table presents items impacting the EBIT in our corporate operations for the years ended December 31:

	2004	**2003**	**2002**
Impairments, contract terminations and gains (losses) on asset sales:			
Telecommunications business	$	$ (396)	$ (168)
LNG business		(108)	
Aircraft.	8	(8)	
Earnings from operations:			
Financial services business	17	21	(18)
Petroleum ship charters	15	1	(13)
Telecommunications business		(44)	(65)
Restructuring charges	(91)	(91)	(51)
Debt gains (losses):			
Foreign currency fluctuations on Euro-denominated debt	(26)	(112)	(95)
Early extinguishment/exchange of debt	(18)	(49)	21
Change in litigation, insurance and other reserves	(116)	(19)	14
Other	(6)	(47)	(12)
Total EBIT	$ (217)	$ (852)	$ (387)

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We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. During 2004, we incurred additional legal costs related to changes in our estimated reserves for these existing legal matters. These changes were based on ongoing assessments, developments and evaluations of the possible outcomes of these matters. We also incurred accretion expense related to our Western Energy Settlement. Our Western Energy Settlement accrual assumes that we will make payments to claimants through 2023. If we retire this obligation earlier than that period, we could incur additional charges. Finally, in 2004, we increased our insurance reserves by approximately $30 million. This accrual related to our decision to withdraw from a mutual insurance company in which we were a member and an accrual for additional premiums in another. In all of our legal and insurance matters, we evaluate each suit and claim as to its merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results.

As discussed in Notes to Consolidated Financial Statements, Note 4, on page F-66, we accrued $80 million in 2004 related to the consolidation of our Houston-based operations. Our estimated relocation costs are based on a discounted liability, which includes estimates of future sublease rentals. Our earnings in future periods will be impacted by the extent to which actual sublease rentals differ from our estimates, and by accretion of this discounted liability, which is estimated to be approximately $8 million for 2005. In total, had estimates of sublease rentals for vacated space that was not subleased as of December 31, 2004 been excluded from our calculations, our discounted liability would have been approximately $121 million versus the amount we recorded. For 2005, if we are unable to collect the estimated sublease rentals included in our accrual, we could incur an additional $3 million in rental expense. We are also pursuing the sale of our telecommunications facility in Chicago. As the sales process progresses we will continue to assess the value of this facility which may result in an impairment.

Interest and Debt Expense

Below is an analysis of our interest and debt expense for each of the three years ended December 31 (in millions):

	2004	2003	2002
Long-term debt, including current maturities	$ 1,510	$ 1,628	$ 1,153
Revolving credit facilities	109	121	16
Commercial paper			26
Other interest	27	73	130
Capitalized interest	(39)	(31)	(28)
Total interest and debt expense	$ 1,607	$ 1,791	$ 1,297

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

During 2004, our total interest and debt expense decreased primarily due to the retirements of long-term debt and other financing obligations (net of issuances) during 2003 and 2004. During 2004, we also paid off $850 million of borrowings under our previous $3 billion revolving credit facility. However, these repayments were offset by $1.25 billion borrowed under the new $3 billion credit agreement entered into in November 2004 and related charges and fees incurred with entering into the new credit agreement.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

During 2003, total interest and debt expense increased compared with 2002 as we issued additional debt securities and consolidated various financing obligations including those associated with Chaparral, Gemstone, Lakeside. We also reclassified certain of our preferred securities as long-term debt. Finally, interest expense on revolving credit facilities increased in 2003 from additional borrowings in 2003 as compared to 2002.

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Distributions on Preferred Interests of Consolidated Subsidiaries

Our distributions on preferred securities decreased significantly between 2002 and 2004. During this period, we redeemed a number of obligations including those related to our Clydesdale, Trinity River, and Coastal Securities financing arrangements. We also reclassified our Coastal Finance I and Capital Trust I mandatorily redeemable securities to long-term debt upon the adoption of SFAS No. 150 in 2003, and began recording the distributions on these securities as interest expense. Our remaining preferred interests at December 31, 2004 consists of $300 million of 8.25% preferred stock of our consolidated subsidiary, El Paso Tennessee Pipeline Co.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Notes to Consolidated Financial Statements, Notes 15 and 16, on pages F-81 through F-88.

Income Taxes

Income taxes for 2004, 2003 and 2002 have been revised to reflect the effects on income taxes of the restatements described in Notes to Consolidated Financial Statements, Note 1, on page F-46.

Income taxes for the years ended December 31, 2004, 2003 and 2002 were $31 million, ($479) million and ($641) million resulting in effective tax rates of (4) percent, 45 percent and 34 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes, net of federal income tax effect;
- earnings/losses from unconsolidated affiliates where we anticipate receiving dividends;
- foreign income taxed at different rates;
- abandonments and sales of foreign investments;
- valuation allowances;
- non-deductible dividends on the preferred stock of subsidiaries;
- non-conventional fuel tax credits; and
- non-deductible goodwill impairments.

For a reconciliation of the statutory rate to our effective tax rate, as well as matters that could impact our future tax expense, see below and Notes to Consolidated Financial Statements, Note 7, on page F-70.

For 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the GulfTerra transactions and the impairments of certain of our foreign investments. The sale of our interests in GulfTerra associated with the merger between GulfTerra and Enterprise in September 2004 resulted in a significant net taxable gain (compared to a lower book gain) and significant tax expense due to the non-deductibility of a significant portion of the goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense in 2004 by approximately $139 million. See Notes to Consolidated Financial Statements, Note 22, on page F-110 for a further discussion of the merger and related transactions. Additionally, we received no U.S. federal income tax benefit on the impairment of certain of our foreign investments. The effective tax rate for 2004 absent these items would have been 32 percent.

For 2003, our overall effective tax rate on continuing operations was significantly different than the statutory rate due, in part, to $53 million of tax benefits related to abandonments and sales of certain of our foreign investments. The effective tax rate for 2003 absent these tax benefits would have been 40 percent.

In 2004, Congress proposed but failed to enact legislation that would disallow deductions for certain settlements made to or on behalf of governmental entities. It is possible Congress will reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax benefits. In such an event, our

tax expense would increase. Our total tax benefits related to the Western Energy Settlement were approximately $400 million as of December 31, 2004.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not provided U.S. deferred taxes on foreign earnings where such earnings were intended to be indefinitely reinvested outside the U.S. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

As part of our long-term business strategy, we anticipate that we will sell our Asian power investments. As further discussed in Notes to Consolidated Financial Statements, Note 7, on page F-70, we have not historically recorded United States deferred taxes on book versus tax basis differences in these investments because our historical intent was to indefinitely reinvest earnings from these projects outside the United States. In 2004, our intent on these assets changed such that we now intend to use the proceeds from the sale within the U.S. As a result, we recorded U.S. deferred tax liabilities for those instances where the book basis in our investment exceeded the tax basis in 2004. At this time, however, due to uncertainties as to the manner, timing and approval of the sale transactions, we have not recorded U.S. deferred tax assets for those instances where the tax basis in our investment exceeded the book basis, except in instances where we believe the realization of the asset is assured. As these uncertainties become known, we will record additional tax effects to reflect the ultimate sale transactions, the amounts of which could have a significant impact on our future recorded tax amounts and our effective tax rates in those periods.

We have a number of pending IRS Audits and income tax contingencies that are in various stages of completion as further discussed in Notes to Consolidated Financial Statements, Note 7, on page F-70. We have provided reserves on these matters that are based on our best estimate of the ultimate outcome of each matter. As these audits are finalized and as these contingencies are resolved, we will adjust our estimates, the impact of which could have a material effect on the recorded amount of income taxes and our effective tax rates in those periods.

Discontinued Operations

Our loss from discontinued operations for 2003 has been restated to properly reflect the classification of income taxes between continuing and discontinued operations related to our discontinued Canadian exploration and production operations, and further restated in 2003 and 2004 to adjust the amount of losses on sales of assets and investments and related tax effects in our discontinued Canadian exploration and production operations and petroleum markets operations which had CTA balances. For a further discussion see Notes to Consolidated Financial Statements, Note 1, on page F-46.

For the year ended December 2004, the loss from our discontinued operations was $114 million compared to a loss of $1,279 million during 2003. In 2004, $36 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from losses on sales and impairment charges, and $78 million was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. The losses in 2003 related primarily to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of our decision to exit and sell these businesses and ceiling test charges related to our Canadian production operations. The loss in 2002 was primarily due to operating losses at our Aruba refinery, impairment charges on our MTBE chemical plant and coal mining operations, and ceiling test charges related to our Canadian production operations.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Notes to Consolidated Financial Statements, Note 17, on page F-89, incorporated herein by reference.

Critical Accounting Policies

Our critical accounting policies are those accounting policies that involve the use of complicated processes, assumptions and/or judgments in the preparation of our financial statements. We have discussed the development and selection of our critical accounting policies and related disclosures with the audit committee of our Board of Directors and have identified the following critical accounting policies for the current year.

Price Risk Management Activities. We record the derivative instruments used in our price risk management activities at their fair values in our balance sheet. 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 our derivative instruments is pricing. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from immediate selected potential changes in quoted market prices:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**Change**	**Fair Value**	**Change**
Derivatives designated as hedges	$ (536)	$ (672)	$ (136)	$ (400)	$ 136
Other commodity-based derivatives	(61)	(84)	(23)	(24)	37
Total	$ (597)	$ (756)	$ (159)	$ (424)	$ 173

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to time value, anticipated market liquidity and credit risk of our counterparties. The assumptions and methodologies that we use to determine the fair values of our derivatives may differ from those used by our derivative counterparties. These differences can be significant and could impact our future operating results as we settle these derivative positions.

Accounting for Natural Gas and Oil Producing Activities. Natural gas and oil reserves estimates underlie many of the accounting estimates in our financial statements as further discussed below. The process of estimating natural gas and oil reserves, particularly proved undeveloped and proved non-producing reserves, is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. Accordingly, our reserve estimates are developed internally by a reserve reporting group separate from our operations group and reviewed by internal committees and internal auditors. In addition, a third party engineering firm which is appointed by, and reports to the Audit Committee of our Board of Directors prepares an independent estimate of a significant portion of our proved reserves. As of December 31, 2004, of our total proved reserves, 29 percent were undeveloped and 13 percent were developed, but non-producing. In addition, the data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates.

The estimates of proved natural gas and oil reserves primarily impact our property, plant and equipment amounts in our balance sheets and the depreciation, depletion and amortization amounts in our income statements, among other items. We use the full cost method to account for our natural gas and oil producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves in full cost pools maintained by geographic areas, regardless of whether reserves are actually discovered. We record depletion expense of these capitalized amounts over the life of our proved reserves based on the unit of production method and, if all other factors are held constant, a 10 percent increase in estimated proved reserves would decrease our unit of production depletion rate by 9 percent and a 10 percent decrease in estimated proved reserves would increase our unit of depletion rate by 11 percent.

Under the full cost accounting method, we are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This impairment test is referred to as a ceiling test. Our total capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues from proved reserves using end of period spot prices and, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. Our ceiling test calculations include the effect of derivative instruments we have designated as, and that qualify as hedges of our anticipated natural gas and oil production. As a result, higher proved reserves can reduce the likelihood of ceiling test impairments. We recorded ceiling test charges in our continuing and discontinued operations of $35 million, $76 million and $128 million during 2004, 2003 and 2002.

The ceiling test calculation assumes that the price in effect on the last day of the quarter is held constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. A decline in commodity prices can impact the results of our ceiling test and may result in writedowns. A decrease in commodity prices of 10 percent from the price levels at December 31, 2004 would not have resulted in a ceiling test charge in 2004.

Asset Impairments. The asset impairment accounting rules require us to continually monitor our businesses and the business environment to determine if an event has occurred indicating that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then assess the expected future cash flows against which to compare the carrying value of the asset group being evaluated, a process which also involves judgment. We ultimately arrive at the fair value of the asset which is determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset). The assessment of project level cash flows requires us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our impairment estimates. We recorded impairments of our long-lived assets of $1.1 billion, $791 million and $440 million during the years ended December 31, 2004, 2003 and 2002 and impairments on our unconsolidated affiliates of $397 million, $449 million, and $566 million during the years ended December 31, 2004, 2003 and 2002. We recorded impairments of our discontinued operations of $9 million, $1.5 billion and $290 million during the years ended December 31, 2004, 2003 and 2002. Future changes in the economic and business environment can impact our assessments of potential impairments.

Accounting for Environmental Reserves. We accrue environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of societal and economic factors, and include estimates of associated onsite, offsite and groundwater technical studies, and legal costs. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each exposure.

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As of December 31, 2004, we had accrued approximately $380 million for environmental matters. Our reserve estimates range from approximately $380 million to approximately $547 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($82 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($298 million to $465 million) and the lower end of the range has been accrued.

Accounting for Pension and Other Postretirement Benefits. As of December 31, 2004, we had a $956 million pension asset and a $274 million other postretirement benefit liability reflected in other assets and liabilities in our balance sheet related to our pension and other postretirement benefit plans. These amounts are primarily based on actuarial calculations. These calculations include assumptions, including those related to the return that we expect to earn on our plan assets, discount rates used in calculating benefit obligations, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plans and other factors.

Actual results may differ from the assumptions included in these calculations, and as a result our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are generally deferred and amortized into income over the life of the plans. The cumulative amount deferred as of December 31, 2004 is recorded as an $800 million increase in our pension asset and a $32 million reduction of our other postretirement liability. The following table shows the impact of a one percent change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2004 (in millions):

	Pension Benefits		Other Postretirement Benefits	
	Net Benefit Expense (Income)	Projected Benefit Obligation	Net Benefit Expense (Income)	Accumulated Postretirement Benefit Obligation
One percent increase in:				
Discount rates	$ (13)	$ (197)	$	$ (37)
Expected return on plan assets	(22)		(1)	
Rate of compensation increase	2	4		
Health care cost trends			1	19
One percent decrease in:				
Discount rates	$ 15	$ 236	$	$ 40
Expected return on plan assets[(1)]	22		1	
Rate of compensation increase	(1)	(4)		
Health care cost trends			(1)	(18)

(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 significantly change.

Our discount rate assumptions reflect the rates of return on the investments we expect to use to settle our pension and other postretirement obligations in the future. We combined current and expected rates of return on investment grade corporate bonds to develop the discount rates used in our benefit expense and obligation estimates as of September 30, 2004.

Our estimates for our net benefit expense (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 and recognized over three years. 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 $14 million higher for the year ended December 31, 2004.

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We have not recorded an additional pension liability for our primary pension plan because the fair value of assets of that plan exceeded the accumulated benefit obligation of that plan by approximately $262 million and $366 million as of September 30, 2004 and December 31, 2004. If the accumulated benefit obligation exceeded plan assets under this primary pension plan as of September 30, 2004, we would have recorded a pre-tax additional pension liability of approximately $960 million, plus an amount equal to the excess of the accumulated benefit obligation over plan assets of that plan. We would have also recorded an amount equal to this additional pension liability to accumulated other comprehensive loss, net of taxes, in our balance sheet.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

Commodity Price Risk

- Natural gas prices change, impacting the forecasted sale of natural gas in our Production segment;
- Price spreads between natural gas and natural gas liquids change, making the natural gas liquids we produce in our Field Services segment less valuable;
- Locational price differences in natural gas change, affecting our ability to optimize pipeline transportation capacity contracts held in our Marketing and Trading segment; and
- Electricity and natural gas prices change, affecting the value of our natural gas contracts, power contracts and tolling contracts held in our Marketing and Trading and Power segments.

Interest Rate Risk

- Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed-rate debt; and
- Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions.

Foreign Currency Exchange Rate Risk

- Weakening or strengthening of the U.S. dollar relative to the Euro can result in an increase or decrease in the value of our Euro-denominated debt obligations and the related interest costs associated with that debt; and
- Changes in foreign currencies exchange rates where we have international investments may impact the value of those investments and the earnings and cash flows from those investments.

We manage these risks by frequently entering into contractual commitments involving physical or financial settlement that attempts to limit the amount of risk or opportunity related to future market movements. Our risk management activities typically involve the use of the following types of contracts:

- Forward contracts, which commit us to purchase or sell energy commodities in the future, involving the physical delivery of an energy commodity, and energy related contracts including transportation, storage, transmission and power tolling arrangements;
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement at a specific price and future date;
- Options, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;

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Swaps, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and

Structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we utilize in our risk management activities are derivative financial instruments. A discussion of our accounting policies for derivative instruments are included in Notes to Consolidated Financial Statements, Notes 1 and 10, on pages F-46 and F-73.

Commodity Price Risk

We are exposed to a variety of commodity price risks in the normal course of our business activities. The nature of these market price risks varies by segment.

Marketing and Trading

Our Marketing and Trading segment attempts to mitigate its exposure to commodity price risk through the use of various financial instruments, including forwards, swaps, options and futures. We measure risks from our Marketing and Trading segment s commodity and energy-related contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to adverse market movements over a defined period of time within a specified confidence level, and monitors our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio s sensitivity to its underlying risks.

Our maximum expected one-day unfavorable impact on the fair values of our commodity and energy-related contracts as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $16 million and $34 million as of December 31, 2004 and 2003. Our highest, lowest and average of the month end values for Value-at-Risk during 2004 was $82 million, $16 million and $38 million. Actual losses in fair value may exceed those measured by Value-at-Risk. Our Value-at-Risk decreased during the fourth quarter of 2004 with the designation of a number of our natural gas derivative contracts as hedges of our Production segment s natural gas production. The exposure of these derivatives to natural gas price fluctuations is now captured in the Production segment discussion below.

Production

Our Production segment attempts to mitigate commodity price risk and to stabilize cash flows associated with its forecasted sales of our natural gas and oil production through the use of derivative natural gas and oil swap contracts. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments we use to mitigate these market risks that were outstanding at December 31, 2004 and 2003. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table. These derivatives do not hedge all of our

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commodity price risk related to our forecasted sales of our natural gas and oil production and as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Change)	Fair Value	Increase
			(In millions)		
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2004	$ (557)	$ (697)	$ (140)	$ (417)	$ 140
December 31, 2003	$ (45)	$ (60)	$ (15)	$ (30)	$ 15

During the fourth quarter of 2004, we designated a number of our Marketing and Trading segment s natural gas derivative contracts as hedges of our Production segment s natural gas production. As a result, the sensitivity of the derivatives in our Production segment to natural gas price changes increased and our Marketing and Trading segment s Value-at-Risk decreased as of December 31, 2004 as discussed above.

Additionally, as of December 31, 2004, our Marketing and Trading segment has entered into derivative contracts designed to provide El Paso with price protection from declines in natural gas prices in 2005 and 2006. These contracts provide us with a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006. In the first quarter of 2005, we entered into additional contracts that provide El Paso with a floor price of $6.00 per MMBtu on 30 TBtu of our natural gas in 2007, and a ceiling price of $9.50 per MMBtu on 60 TBtu of our natural gas production in 2006. The commodity price risk associated with these contracts are not included in the sensitivity analysis, but rather are included in our Value-at-Risk calculation discussed above.

Field Services

Our Field Services segment does not significantly utilize financial instruments to mitigate our exposure to the natural gas liquids it retains in its processing operations since this exposure is not material to our overall operations.

Interest Rate Risk

Debt

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average interest rates on our interest-bearing securities, by expected maturity dates and the fair values of those securities. As of December 31, 2004 and 2003, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term securities has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2004								December 31, 2003	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
					(Dollars in millions)					
Liabilities:										
	$ 7						$ 7	$ 8	$ 8	$ 8

Short-term debt fixed rate										
Average interest rate	6.2%									
Long-term debt and other obligations, including current portion fixed rate	$ 740	$ 1,111	$ 797	$ 703	$ 1,464	$ 12,932	$ 17,747	$ 18,387	$ 20,152	$ 19,594
Average interest rate	8.2%	6.7%	7.3%	7.5%	6.1%	7.6%				
Long-term debt and other obligations, including current portion variable rate	$ 197	$ 33	$ 27	$ 20	$ 1,165	$	$ 1,442	$ 1,442	$ 1,572	$ 1,572
Average interest rate	9.1%	4.8%	4.7%	5.6%	5.6%					

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Derivatives from Power Contract Restructuring Activities

Derivatives associated with our power contract restructuring business of our Power segment are valued using estimated future market power prices and a discount rate that considers the appropriate U.S. Treasury rate plus a credit spread specific to the contract s counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in value that can be realized in a current transaction between willing parties. Since September 30, 2002, in order to provide for market risk, we have not reflected the increase in value that would result from decreases in U.S. Treasury rates because we believe the resulting increase in the value of these non-trading derivatives could not be realized in a current transaction between willing parties. To the extent there is commodity price risk associated with these derivative contracts, it is included in our Value-at-Risk calculation discussed above, but our exposure to changes in interest rates and credit spreads has not been included in our Value-at-Risk calculation. Historically, our interest rate risk associated with these contracts primarily related to UCF and Cedar Brakes I and II. As a result of the sale of UCF in 2004 and our sale of Cedar Brakes I and II in March 2005, our sensitivity to interest rate changes on our remaining restructured power contract derivatives will be minimal.

Foreign Currency Exchange Rate Risk

Debt

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2004, we have Euro-denominated debt with a principal amount of 1,050 million of which 550 million matures in 2006 and 500 million matures in 2009. As of December 31, 2004 and 2003, we had swaps that effectively converted 725 million and 625 million of debt into $766 million and $645 million. The remaining principal at December 31, 2004 and 2003 of 325 million and 425 million was subject to foreign currency exchange risk.

In March 2005, we repurchased approximately 528 million of our debt maturing in 2006. After this repurchase, our unhedged Euro-denominated debt that is subject to foreign currency exchange risk totaled 172 million. As a result, a hypothetical ten percent increase or decrease in the Euro/ USD exchange rate of 1.3188 as of the date of repurchase, with all other variables held constant, would increase or decrease the carrying value of our remaining unhedged Euro-denominated debt after the repurchase by approximately $23 million.

Power Contracts

Several of our international power plants in Asia, Central America, South America and Europe have long-term power sales contracts that are denominated in the local country s currencies. As a result, we are subject to foreign currency exchange risk related to these power sales contracts. We do not believe that this exposure is material to our operations and have not chosen to mitigate this exposure.

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Quarter and Six Months Ended June 30, 2005 and 2004

During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

Overview

Since the beginning of 2005, we have completed the following activities in connection with the ongoing execution of our strategic plan:

Our pipeline segment made further progress on its plans by settling a rate case at SNG, recontracting with large customers on the SNG and EPNG systems, and making progress on several pipeline expansion projects in our pipeline systems and at our Elba Island LNG facility;

Our production segment continued to make progress on its turnaround and the stabilization of its production rates through its capital program and four strategic acquisitions of natural gas and oil properties totalling approximately $1.1 billion, including our recently announced Medicine Bow acquisition which we expect to close in the third quarter of 2005 for approximately $814 million;

We continued the exit of our legacy trading business through the assignment or termination of derivative contracts associated with Cedar Brakes I and II;

We completed the sale of a number of assets and investments including, among others, our remaining general and limited partnership interests in Enterprise, interests in Cedar Brakes I and II, the Lakeside Technology Center, and our interest in a Korean power facility. Total proceeds from these sales were approximately $1.2 billion ($918 million through June 30, 2005);

We reduced our net debt to $15.9 billion (debt of $17.48 billion, net of cash of $1.54 billion) as of June 30, 2005, lowering our net debt by $1.1 billion; and

We completed a private placement of $750 million of 4.99% convertible perpetual preferred stock. The proceeds from this offering were used to prepay our remaining deferred payment obligation on the Western Energy Settlement for $442 million and to redeem the $300 million of EPTP, 8.25%, Series A cumulative preferred stock.

Capital Resources and Liquidity

Our 2004 Management s Discussion and Analysis of Financial Condition and Results of Operations beginning on page 22 includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, that information.

During the six months ended June 30, 2005, we continued to reduce our overall debt as part of our Long Range Plan announced in December 2003. Our activity during the six months ended June 30, 2005 was as follows (in millions):

Short-term financing obligations, including current maturities	$ 955
Long-term financing obligations	18,241
Total debt as of December 31, 2004	19,196
Principal amounts borrowed	466
Repayments/retirements of principal	(1,563)
Sales of entities[(1)]	(546)
Other reductions	(75)

Total debt as of June 30, 2005	$	17,478

(1) Related to the sale of Cedar Brakes I and II.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Notes to Condensed Consolidated Financial Statements, Note 9, on page F-17.

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Our net available liquidity as of June 30, 2005 was $1.7 billion, which consisted of $0.4 billion of availability under our $3 billion credit agreement and $1.3 billion of available cash. The availability of borrowings under our credit agreement and our ability to incur additional debt is subject to various conditions as further described in Notes to condensed consolidated financial statements, Note 9, on page F-17 and Notes to Consolidated Financial Statements, Note 15, on page F-81, which we currently meet. These conditions include compliance with financial covenants and ratios requiring our Debt to Consolidated EBITDA not to exceed 6.5 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in our $3 billion credit agreement. As of June 30, 2005, our ratio of Debt to Consolidated EBITDA was 4.68 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 2.06 to 1.

We believe we will be able to meet our ongoing liquidity and cash needs through the combination of available cash, cash flow from operations and borrowings under our $3 billion credit agreement. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans as further discussed in Risk Factors beginning on page 7.

Overview of Cash Flow Activities for 2005 Compared to 2004

For the six months ended June 30, 2005 and 2004, our cash flows are summarized as follows:

	2005	2004
	(In billions)	
Cash Inflows		
Continuing operating activities		
Net loss before discontinued operations	$ (0.1)	$ (0.1)
Non-cash income adjustments	0.9	0.8
Change in assets and liabilities	(0.8)	(0.6)
		0.1
Continuing investing activities		
Net proceeds from the sale of assets and investments	0.8	0.2
Proceeds from settlement of foreign currency derivatives	0.1	
Reduction of restricted cash	0.1	0.4
Other	0.1	0.1
	1.1	0.7
Continuing financing activities		
Net proceeds from the issuance of long-term debt	0.5	0.1
Proceeds from the issuance of preferred and common stock	0.7	0.1
Contributions from discontinued operations	0.1	0.9
	1.3	1.1
Total cash inflows	$ 2.4	$ 1.9
Cash Outflows		
Continuing investing activities		
Additions to property, plant and equipment	$ 0.8	$ 0.8

Net cash paid for acquisitions	0.2	
	1.0	0.8
Continuing financing activities		
Payments to retire debt and redeem preferred interests	1.6	1.0
Redemption of preferred stock	0.3	
Other	0.1	0.1
	2.0	1.1
Total cash outflows	$ 3.0	$ 1.9
Net change in cash	$ (0.6)	$

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Cash From Continuing Operating Activities

Overall, cash inflows from our continuing operating activities for the first six months of 2005 were slightly below cash inflows from continuing operating activities during the same period of 2004. The decrease in operating cash flow in 2005 as compared to 2004 was due primarily to differences in working capital utilization in the two periods. In the first six months of 2005, we experienced a $0.8 billion use of working capital, which included a $0.2 billion payment to assign or terminate derivative contracts in connection with the sale of Cedar Brakes I and II, $0.2 billion of hedging derivative settlements and $0.4 billion for the prepayment of the Western Energy Settlement. In the first six months of 2004, we experienced a $0.6 billion use of working capital primarily due to a payment to settle the principal litigation under the Western Energy Settlement.

Cash From Continuing Investing Activities

Net cash provided by our continuing investing activities was $0.1 billion for the six months ended June 30, 2005. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$	(0.6)
Pipeline expansion, maintenance and integrity projects		(0.3)
Decrease in restricted cash		0.1
Settlement of a foreign currency derivative		0.1
Proceeds from sales of assets and investments		0.8
Total continuing investing activities	$	0.1

Cash received from sales of assets and investments was primarily from the sale of our remaining interests in Enterprise and the sale of the Lakeside Technology Center. The settlement of a foreign currency derivative relates to cash received on a derivative entered into to hedge currency and interest rate risk on a portion of our Euro denominated debt. This derivative was settled upon the retirement of that debt. In July 2005, we announced that we will acquire Medicine Bow for $0.8 billion. The acquisition will be funded by existing cash on hand and a new $500 million, five-year revolving credit facility, which will be collateralized by a portion of EPPH s existing natural gas and oil reserves. We intend to repay this facility within one year from closing through an issuance of equity. We also expect additional capital expenditures of $0.3 billion in our Production segment and $0.7 billion in our Pipelines segment during the remainder of 2005.

Cash From Continuing Financing Activities

Net cash used in our continuing financing activities was $0.7 billion for the six months ended June 30, 2005. We generated cash of $1.2 billion from the issuance of $0.7 billion of convertible preferred stock, and $0.5 billion of long-term debt on CIG and Cheyenne Plains. However, we made repayments of $0.9 billion to retire third party long-term debt, paid $0.7 billion to retire a portion of our Euro-denominated debt and redeemed $0.3 billion of cumulative preferred stock of EPTP, our subsidiary.

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Commodity-based Derivative Contracts

We use derivative financial instruments in our hedging activities, power contract restructuring activities and in our historical energy trading activities. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of June 30, 2005:

Source of Fair Value	Maturity Less Than 1 year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges						
Assets	$ 16	$ 9	$	$	$	$ 25
Liabilities	(423)	(196)	(27)	(19)		(665)
Total derivatives designated as hedges	(407)	(187)	(27)	(19)		(640)
Assets from power contract restructuring derivatives(1)	20	40				60
Other commodity-based derivatives						
Exchange-traded positions(2)						
Assets	115	243	135	13		506
Liabilities	(102)	(9)	(1)			(112)
Non-exchange-traded positions						
Assets	421	379	197	151	27	1,175
Liabilities(1)	(394)	(591)	(312)	(186)	(50)	(1,533)
Total other commodity-based derivatives	40	22	19	(22)	(23)	36
Total commodity-based derivatives	$ (347)	$ (125)	$ (8)	$ (41)	$ (23)	$ (544)

(1) Includes $6 million of intercompany derivatives that eliminate in consolidation and had no impact on our consolidated assets and liabilities from price risk management activities for the six months ended June 30, 2005.

(2) Exchange-traded positions are those traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London Clearinghouse.

Below is a reconciliation of our commodity-based derivatives for the period from January 1, 2005 to June 30, 2005:

	Derivatives	Derivatives from Power Contract	Other Commodity-	Total Commodity-

	Designated as Hedges[1]	Restructuring Activities	Based Derivatives	Based Derivatives
		(In millions)		
Fair value of contracts outstanding at January 1, 2005	$ (536)	$ 665	$ (61)	$ 68
Fair value of contract settlements during the period	182	(616)	282	(152)
Change in fair value of contracts	(286)	11	(182)	(457)
Option premiums received, net			(3)	(3)
Net change in contracts outstanding during the period	(104)	(605)	97	(612)
Fair value of contracts outstanding at June 30, 2005	$ (640)	$ 60	$ 36	$ (544)

(1) In December 2004, we designated a number of our other commodity-based derivative contracts in our Marketing and Trading segment as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this $592 million liability to derivatives designated as hedges in December 2004.

The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts.

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In March 2005, we sold our Cedar Brakes I and II subsidiaries and their related restructured power contracts, which had a fair value of $596 million as of December 31, 2004. In connection with the sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of $240 million as of December 31, 2004.

The change in fair value of contracts during the period represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement or, if not settled, until the end of the period.

Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our regulated business consists of our Pipelines segment, while our unregulated businesses consist of our Production, Marketing and Trading, Power and Field Services segments. 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. Our corporate activities include our general and administrative functions, as well as a telecommunications business and various other contracts and assets. During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or

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operating cash flow. Below is a reconciliation of our consolidated EBIT to our consolidated net income (loss) for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Regulated Business				
Pipelines	$ 309	$ 308	$ 721	$ 694
Non-regulated Businesses				
Production	176	204	359	408
Marketing and Trading	(30)	(152)	(215)	(316)
Power	(381)	102	(431)	(67)
Field Services	(3)	27	179	63
Segment EBIT	71	489	613	782
Corporate	(12)	9	(102)	36
Consolidated EBIT from continuing operations	59	498	511	818
Interest and debt expense	(340)	(410)	(690)	(833)
Distributions on preferred interests of consolidated subsidiaries	(3)	(6)	(9)	(12)
Income taxes	51	(48)	57	(58)
Income (loss) from continuing operations	(233)	34	(131)	(85)
Discontinued operations, net of income taxes	(5)	(29)	(1)	(106)
Net income (loss)	$ (238)	$ 5	$ (132)	$ (191)

Overview of Segment Results

For the six months ended June 30, 2005, our segment EBIT was $613 million. During the six month period, our Pipelines, Production and Field Services segments contributed $1,259 million of combined EBIT. These positive contributions were partially offset by the EBIT losses of $215 million in our Marketing and Trading segment and $431 million in our Power segment. The following overview summarizes the results of operations by operating segment compared to our internal expectations for the period.

Pipelines Our Pipelines segment generated EBIT of $721 million, which was slightly above our expectations for the period.

Production Our Production segment generated EBIT of $359 million, which was slightly above our expectations for the period. Lower than expected production volumes and higher depreciation and production costs were more than offset by higher than expected commodity prices.

Marketing and Trading Our Marketing and Trading segment generated an EBIT loss of $215 million, which was a greater loss than our expectations. The performance was driven by significant mark-to-market losses on our production-related derivatives due to natural gas price increases during the period. In addition, our power contracts, primarily our Cordova tolling agreement,

	experienced significant losses during the period due to changes in natural gas and power prices.
Power	Our Power segment generated an EBIT loss of $431 million, which was a greater loss than expected and was impacted by significant impairments of our Macae project in Brazil and impairments of our Asian and Central American power assets based on additional information received about the value we may receive upon the sale of these assets.
Field Services	Our Field Services segment generated EBIT of $179 million, which was consistent with our expectations and was primarily due to the gain on the sale of our remaining interests in Enterprise.

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For the remainder of 2005, we expect the trends discussed above to continue in our Pipeline and Production segments, given the historic stability in our pipeline business and the current favorable pricing environment for natural gas and oil. We also anticipate our Marketing and Trading segment s EBIT will continue to be volatile due to changes in natural gas and power prices as they relate to our trading portfolio. In our Power segment, we may generate EBIT losses as we continue to sell or pursue the sale of our Asian and Central American power plant portfolio and continue negotiations with Petrobras relating to our Macae power investment. Finally, we expect our EBIT to decline in our Field Services segment as a result of the completion of sales of substantially all of our remaining gathering and processing assets. Below is a discussion of our individual segment results.

Regulated Business Pipelines Segment

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
Pipelines Segment Results	**2005**	**2004**	**2005**	**2004**
	(In millions except volume amounts)			
Operating revenues	$ 653	$ 617	$ 1,421	$ 1,338
Operating expenses	(391)	(357)	(797)	(730)
Operating income	262	260	624	608
Other income	47	48	97	86
EBIT	$ 309	$ 308	$ 721	$ 694
Throughput volumes (BBtu/d)	20,316	19,935	21,444	21,223

The following contributed to our overall EBIT increase of $1 million and $27 million for the quarter and six months ended June 30, 2005 as compared to the same periods in 2004:

	Quarter Ended June 30,				Six Months Ended June 30,			
	Revenue	**Expense**	**Other**	**EBIT**	**Revenue**	**Expense**	**Other**	**EBIT**
	Favorable/(Unfavorable) (In millions)				**Favorable/(Unfavorable) (In millions)**			
Contract modifications/ terminations/ settlements	$ 14	$	$ 1	$ 15	$ 46	$	$ 1	$ 47
Gas not used in operations, processing revenues and other natural gas sales	(1)	10		9	19	1		20
Favorable resolution in 2004 of measurement dispute at a processing plant					(10)			(10)
Pipeline expansions	22	(8)	2	16	38	(15)	2	25
Higher allocated costs		(25)		(25)		(46)		(46)

Equity earnings from our investment in Citrus			(3)	(3)			5	5
Other[1]	1	(11)	(1)	(11)	(10)	(7)	3	(14)
Total impact on EBIT	$ 36	$ (34)	$ (1)	$ 1	$ 83	$ (67)	$ 11	$ 27

[1] Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Contract Modifications/ Terminations/ Settlements. Included in this item are (i) the impact of ANR completing the restructuring of its transportation contracts with one of its shippers on its Southwest and Southeast Legs as well as a related gathering contract in March 2005, which increased revenues and EBIT by $29 million in the first quarter of 2005 (ii) the impact of ANR s settlement in the second quarter of 2005 of two transportation agreements previously rejected in the bankruptcy of USGen New England, Inc., which

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increased EBIT by $15 million and (iii) the impact of the termination, in April 2004, of EPNG s restrictions on remarketing expiring capacity contracts resulting in increased revenues and EBIT of $5 million during the first six months of 2005 as compared to 2004. ANR s settlement with USGen will not have an ongoing impact on our Pipelines segment results.

SoCal successfully acquired approximately 750 MMcf/d of capacity on EPNG s system under new contracts with various terms extending from 2009 to 2011 commencing September 2006. We are in the process of consummating the transaction entered into in December 2004 by executing the relevant transportation service agreements with SoCal. Effective September 2006, approximately 500 MMcf/d of capacity formerly held by SoCal to serve its non-core customers will be available for recontracting. We are continuing in our efforts to remarket the remaining expiring capacity to serve SoCal s non-core customers or to serve new markets. We are also pursuing the option of using some or all of this capacity to provide new services to existing markets. At this time, we are uncertain how much of this remaining capacity formerly held by SoCal will be recontracted, and if so at what rates.

Gas Not Used in Operations, Processing Revenues and Other Natural Gas Sales. For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to our tariffs or FERC orders, relative to the amount of gas we use for operating purposes, and the price of natural gas. Gas not needed for operations results in revenues to us, which are driven by volumes and prices during a given period. These recoveries of gas on our systems relative to amounts we use are based on factors such as system throughput, facility enhancements and the ability to operate the systems in the most efficient and safe manner. In 2005, the sale of higher volumes of natural gas made available by storage realignment projects was partially offset by higher volumes of gas utilized in operations, resulting in an overall favorable impact on our operating results in 2005 versus 2004. We anticipate that this overall activity will continue to vary in the future and will be impacted by things such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors.

Expansions. In June 2005, SNG filed with the FERC for permission to construct a 176 mile expansion of its system which will provide 500,000 Mcf/d of firm transportation to be phased in over four years beginning in May 2007. Total cost estimates for the project are approximately $321 million and construction is expected to begin upon FERC approval in 2006. This expansion is currently expected to increase our revenues by an estimated $62 million annually.

As of January 31, 2005, our Cheyenne Plains pipeline was placed in-service. As a result, revenues increased by $28 million and overall EBIT increased by $13 million during the first six months of 2005 compared to the same period in 2004.

In April 2003, the FERC approved the expansion of the Elba Island LNG facility to increase the base load sendout rate of the facility from 446 MMcf/d to 806 MMcf/d. Our current cost estimates for the expansion are approximately $157 million and as of June 30, 2005, our expenditures were approximately $118 million. We commenced construction in July 2003 and expect to place the expansion in service in February 2006. As a result of increasing levels of capital invested in the expansion, higher AFUDC in 2005 resulted in higher EBIT compared to 2004. This expansion is currently expected to increase our revenues by an estimated $29 million annually.

In June 2005, the FERC issued a certificate authorizing CIG to construct the Raton Basin expansion, which will add 104 MMcf/d of capacity to its system. The project is fully subscribed for 10 years, of which 14 percent is held by an affiliate. Construction began in June and the project is expected to be in service by October 2005. This expansion is currently expected to increase revenues by an estimated $9 million in 2006 and an estimated $13 million annually thereafter.

In order to meet increased demand in EPNG s markets and comply with FERC orders, EPNG completed Phases I, II and III of its Line 2000 Power-up project in 2004, which increased the capacity of that line by 320 MMcf/d. In addition, in June 2005, EPNG received FERC certificate approval for the EPNG Cadiz to Ehrenberg project that will increase its north-to-south capacity by 372 MMcf/d. The project is scheduled to be in service by late 2005. Construction and conversion will begin as soon as we receive approval from the California State Land Commission and the U.S. Department of the Interior s Bureau of Land Management. EPNG expects to earn revenues associated with these expansions beginning in January 2006, the effective date of its recent rate filing.

Allocated Costs. We allocate general and administrative costs to each business segment. The allocation is based on the estimated level of effort devoted to each segment s operations and the relative size of its EBIT, gross property and payroll as compared to our consolidated totals. During the quarter and six months ended June 30, 2005, the Pipelines segment was allocated higher costs than the same periods in 2004, primarily due to an increase in our benefits accrued under our retirement plan and higher legal, insurance and professional fees. In addition, we were allocated a larger percentage of El Paso s total corporate costs due to the significance of our asset base and earnings to the overall El Paso asset base and earnings.

Accounting for Pipeline Integrity Costs. In June 2005, the FERC issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs. This release will require us to expense certain pipeline integrity costs incurred after January 1, 2006 instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact that this accounting release will have on our consolidated financial statements, we currently estimate that we would be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $23 million to $39 million annually.

Regulatory and Other Matters

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability.

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, subject to refund, and also proposing new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. The rate case would be effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG s former full requirements (FR) customers under the terms of its FERC approved systemwide capacity allocation proceeding will expire on January 1, 2006. The combined effect of the proposed increase in tariff rates and the expiration of the lower rates to EPNG s FR customers are estimated to increase our revenues by approximately $138 million. In July 2005, the FERC accepted certain of the proposed tariff revisions, including the adoption of a fuel tracking mechanism and set the rate case for hearing and technical conference. The FERC directed the scheduling of the technical conference within 150 days of the order and delayed setting a date for the hearing pending resolution of the various matters identified for consideration at the technical conference. We anticipate continued discussions with intervening parties in an attempt to settle the matter and are uncertain of the settlement of this rate case. For a further discussion of our current and upcoming rate proceedings, see pages 100 through 109.

The FERC has initially rejected a request made by EPNG in the rate case filed on June 25, 2005 for a tracking mechanism that would have provided an assurance of recovery of the cost of a right-of-way across Navajo Nation land. However, the FERC did invite EPNG to seek a waiver of FERC regulations to permit the cost of the right-of-way to be included in its pending rate case if the final cost becomes known and measurable within a reasonable time after the close of the test period on December 31, 2005. The timing and/or extent of recovery could impact our future financial results.

SNG Rate Case and Other Matter. In August 2004, SNG filed a rate case with the FERC seeking an annual rate increase of $35 million, or 11 percent in jurisdictional rates and certain revisions to its effective tariff regarding terms and conditions of service. In April 2005, SNG reached a tentative settlement in principle that would resolve all issues in our rate proceeding, and filed the negotiated offer of settlement with the FERC on April 20, 2005. SNG implemented the settlement rates on an interim basis as of March 1, 2005 as negotiated rates with all shippers which elected to be consenting parties under the rate settlement. In an order issued in July 2005, the FERC approved the settlement. Under the terms of the settlement, SNG reduced the

proposed increase in its base tariff rates by approximately $21 million; reduced its fuel retention percentage and agreed to an incentive sharing mechanism to encourage additional fuel savings; received approval for capital maintenance tracker that will allow it to recover costs through its rates; adjusted the rates for its South Georgia facilities and agreed to file its next general rate case no earlier than March 1, 2009 and no later than March 31, 2010. The settlement also provided for changes regarding SNG s terms and conditions of service. We do not expect the settlement to have a material impact on its future financial results. In addition, as a result of the contract extensions required by the settlement, the contract terms for firm service now average approximately seven years.

A majority of SNG contracts for firm transportation service with its largest customer, Atlanta Gas Light Company (AGL), were due to expire in 2005. In April 2004, SNG and AGL executed definitive agreements pursuant to which AGL agreed to extend its firm transportation service contracts with SNG for 926,534 Mcf/d for a weighted average term of 6.5 years between 2008 and 2015. In connection with this agreement, SNG sold to AGL approximately 250 miles of certain pipeline facilities and nine measurement facilities in the metropolitan Atlanta area for a transfer price of approximately $32 million. In late 2004 and early 2005 the FERC and the Georgia Public Service Commission (GPSC) approved these transactions. In March 2005, the transaction was closed and SNG recorded a gain of $7 million from the sale of these facilities.

For a further discussion of our current and upcoming rate proceedings, see Notes to Consolidated Financial Statements, Note 17 on page F-89.

Non-regulated Business Production Segment

Overview

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment are driven by a variety of factors including the ability to acquire or locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and to minimize our total administrative costs. We continue to manage our business with a goal to stabilize production by improving the production mix across our operating areas through a more balanced allocation of our capital to development and exploration projects, and through acquisition activities with low risk development opportunities that provide operating synergies with our existing operations.

Significant Operational Factors Since December 31, 2004

Since December 31, 2004, we have experienced the following:

Higher realized prices. During the first six months of 2005, we continued to benefit from a strong commodity pricing environment. Realized natural gas prices, which include the impact of our hedges, increased eight percent while oil, condensate and NGL prices increased 33 percent compared to 2004.

Average daily production of 775 MMcfe/d (excluding discontinued operations of 3 MMcfe/d). Our average daily production in the second quarter of 2005 increased approximately two percent over the first quarter of 2005 and was relatively stable compared with the third and fourth quarters of 2004. Specifically, during the last twelve months we have experienced increased production in our onshore region, relatively stable production in our offshore Gulf of Mexico region, and declining production in our Texas Gulf Coast region due to normal declines and mechanical well failures. In addition, we acquired the remaining interest in UnoPaso located in Brazil in July 2004 and began consolidating this operation. During the first six months of 2005, our operations in Brazil produced at an average of approximately 54 MMcfe/d, and our first quarter 2005 acquisitions of domestic producing properties discussed below benefited our average daily production by approximately 44 MMcfe/d. In July 2005, hurricanes in the Gulf of Mexico caused us to shut in production for periods of time impacting production volumes by approximately 12 MMcfe/d for the month.

Acquisitions and other capital expenditures. During the first six months of 2005, our capital expenditures of $651 million included acquisitions in east and south Texas and the purchase of the interest held by one of our partners under a net profits interest agreement for a total of $271 million. These acquisitions added properties with approximately 140 Bcfe of proved reserves and 52 MMcfe/d of production at the acquisition dates. More importantly, the Texas acquisitions offer additional exploration upside in two of our key operating areas. We have integrated these acquisitions into our operations with minimal additional administrative expenses.

In July 2005, we announced we will acquire Medicine Bow, a privately held energy company with an estimated 356 Bcfe of proved reserves, primarily in the Rocky Mountains and east Texas, for $814 million. Of this proved reserve amount, our net interest in approximately 226 Bcfe will not be consolidated in our reserves, as these reserves are owned by an unconsolidated affiliate of Medicine Bow. The operating results associated with these unconsolidated reserves will be reported through an equity interest. Concurrent with this announcement, our Marketing and Trading segment entered into several derivative positions associated with the properties to be acquired as further discussed on page 89. The acquisition of these properties will complement our existing core operations, diversify our commodity mix and increase our reserve life. The transaction is expected to close during the third quarter of 2005.

Drilling Results. In 2005, we have announced deep shelf discoveries at West Cameron Block 75 and Block 62 in the Gulf of Mexico. At West Cameron Block 75, we tested the discovery and anticipate deliverability of approximately 40 MMcfe/d to begin in the fourth quarter of 2005, after the installation of facilities. We own a 36 percent working interest and an approximate 30 percent net revenue interest in the West Cameron Block 75.

Outlook for the last six months of 2005

For 2005, we anticipate the following:

Total capital expenditures of approximately $1.1 billion for the last six months of 2005, including amounts to be paid to acquire Medicine Bow.

Daily production volumes for the year to average in excess of 810 MMcfe/d, including approximately 10 MMcfe/d expected from the Medicine Bow acquisition and 24 MMcfe/d from Medicine Bow s interest in an unconsolidated affiliate.

Cash operating costs to be approximately $1.45/Mcfe as we continue to focus on cost control, operating efficiencies, and process improvements.

Industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs.

A domestic unit of production depletion rate of $2.10/ Mcfe in the third quarter of 2005 as compared to $2.04/ Mcfe in the second quarter of 2005, due to higher finding and development costs and the costs of acquired reserves. We also expect a higher depletion rate in the fourth quarter of 2005 as we complete the announced Medicine Bow acquisition.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment and acquisition programs. Our Marketing and Trading segment has also entered into other derivative contracts that are designed to provide price protection to the overall company, which are discussed further in that segment s operating results. Our hedging activities are further discussed beginning on page 89.

Overall, we experienced a significant decrease in the fair value of our hedging derivatives in the first six months of 2005. These non-cash fair value decreases are generally deferred in our accumulated other comprehensive income and will be realized in our operating results at the time the production volumes to which they relate are sold. As of June 30, 2005, the fair value of these positions that is deferred in accumulated other comprehensive income was a pre-tax loss of $281 million. The income impact of the settlement of these derivatives will be substantially offset by the impact of the corresponding change in the price to be received when the hedged production is sold.

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Operating Results

Below are the operating results and analysis of these results for the periods ended June 30:

Production Segment Results	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Operating Revenues:				
Natural gas	$ 354	$ 363	$ 707	$ 731
Oil, condensate and NGL	96	66	181	143
Other	2	1	3	2
Total operating revenues	452	430	891	876
Transportation and net product costs(1)	(12)	(13)	(25)	(27)
Total operating margin	440	417	866	849
Operating Expenses:				
Depreciation, depletion and amortization	(157)	(131)	(303)	(271)
Production costs(2)	(59)	(44)	(114)	(86)
Restructuring charges	(2)	(2)	(2)	(11)
General and administrative expenses	(43)	(37)	(84)	(73)
Taxes other than production and income	(4)	(1)	(8)	(3)
Total operating expenses(1)	(265)	(215)	(511)	(444)
Operating income	175	202	355	405
Other income	1	2	4	3
EBIT	$ 176	$ 204	$ 359	$ 408

	Quarter Ended June 30,			Six Months Ended June 30,		
	2005	2004	Percent Variance	2005	2004	Percent Variance
Volumes, prices and costs:						
Natural gas						
Volumes (MMcf)	57,790	61,535	(6)%	113,948	127,234	(10)%
Average realized prices including hedges ($/Mcf) (3)(4)	$ 6.13	$ 5.90	4%	$ 6.20	$ 5.75	8%
Average realized prices excluding hedges ($/Mcf)(3)	$ 6.35	$ 5.95	7%	$ 6.03	$ 5.81	4%
Average transportation costs ($/Mcf)	$ 0.17	$ 0.14	21%	$ 0.17	$ 0.15	13%
Oil, condensate and NGL						

Volumes (MBbls)	2,260	1,937	17%	4,396	4,647	(5)%
Average realized prices including hedges ($/Bbl)[3]	$ 42.39	$ 34.11	24%	$ 41.16	$ 30.86	33%
Average realized prices excluding hedges ($/Bbl)[3]	$ 43.07	$ 34.11	26%	$ 41.68	$ 30.86	35%
Average transportation costs ($/Bbl)	$ 0.59	$ 1.54	(62)%	$ 0.67	$ 1.35	(50)%
Total equivalent volumes (MMcfe)	71,351	73,157	(2)%	140,327	155,115	(10)%
Production costs ($/Mcfe)						
Average lease operating cost	$ 0.76	$ 0.51	49%	$ 0.69	$ 0.50	38%
Average production taxes	0.07	0.09	(22)%	0.13	0.06	117%
Total production cost[1]	$ 0.83	$ 0.60	38%	$ 0.82	$ 0.56	46%
Average general and administrative cost ($/Mcfe)	$ 0.61	$ 0.51	20%	$ 0.60	$ 0.47	28%
Unit of production depletion cost ($/Mcfe)	$ 2.05	$ 1.64	25%	$ 2.02	$ 1.61	25%

(1) Transportation and net product costs are included in operating expenses on our consolidated statements of income.

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

(3) Prices are stated before transportation costs

(4) The average realized prices for natural gas, including hedges listed above, reflect the amounts recorded by the Production segment for sales of natural gas volumes. On a consolidated basis, El Paso receives a lower cash price on a portion of the volumes sold as further discussed on page 32.

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Quarter and Six Months Ended June 30, 2005 Compared to Quarter and Six Months Ended June 30, 2004

Our EBIT for the quarter and six months ended June 30, 2005 decreased $28 million and $49 million as compared to the quarter and six months ended June 30, 2004. The table below lists the significant variances in our operating results in the quarter and six months ended June 30, 2005 as compared to the same periods in 2004:

	Variance			
Quarter Ended June 30,	**Operating Revenue**	**Operating Expense**	**Other[(1)]**	**EBIT Impact**
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 23	$	$	$ 23
Lower volumes in 2005	(22)			(22)
Impact from hedge program in 2005 versus 2004	(10)			(10)
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	20			20
Higher volumes in 2005	11			11
Impact from hedge program in 2005 versus 2004	(1)			(1)
Depreciation, Depletion, and Amortization Expense				
Higher depletion rate in 2005		(29)		(29)
Lower production volumes in 2005		3		3
Production Costs				
Higher lease operating costs in 2005		(17)		(17)
Lower production taxes in 2005		2		2
Other				
Higher general and administrative costs in 2005		(6)		(6)
Other	1	(3)		(2)
Total variances	$ 22	$ (50)	$	$ (28)

	Variance			
Six Months Ended June 30,	**Operating Revenue**	**Operating Expense**	**Other[(1)]**	**EBIT Impact**
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 25	$	$	$ 25
Lower volumes in 2005	(77)			(77)
Impact from hedge program in 2005 versus 2004	28			28
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	48			48
Lower volumes in 2005	(8)			(8)
Impact from hedge program in 2005 versus 2004	(2)			(2)

Depreciation, Depletion, and Amortization Expense								
Higher depletion rate in 2005				(58)				(58)
Lower production volumes in 2005				24				24
Production Costs								
Higher lease operating costs in 2005				(19)				(19)
Higher production taxes in 2005				(9)				(9)
Other								
Higher general and administrative costs in 2005				(11)				(11)
Other		1		6		3		10
Total variances	$	15	$	(67)	$	3	$	(49)

(1) Consists primarily of changes in transportation costs and other income

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Operating Revenues. During 2005, we continued to benefit from a strong commodity pricing environment for natural gas and oil, condensate and NGL. Our hedging program contributed (losses) gains of ($14) million and $17 million for the quarter and six months ended June 30, 2005, compared to ($3) million and ($9) million for the same periods in 2004. Substantially offsetting the impact of the strong commodity pricing environment was a decrease in production volumes versus the same periods in 2004. Although our natural gas and oil production benefited from our east and south Texas acquisitions, our acquisition and consolidation of the remaining interests in UnoPaso in Brazil in July 2004 and increased production in our onshore region, both the Texas Gulf Coast and the offshore regions experienced significant decreases in production due to normal production declines and a lower capital spending program over the last several years. In addition, the Texas Gulf Coast Region was impacted by mechanical well failures.

Depreciation, depletion, and amortization expense. Lower production volumes in 2005 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. However, more than offsetting this decrease were higher depletion rates due to higher finding and development costs and the cost of acquired reserves.

Production costs. In 2005, we experienced additional costs, including workover costs, as a result of our July 2004 acquisition of UnoPaso located in Brazil, higher domestic workover costs due to the implementation of programs to improve production in the offshore Gulf of Mexico and Texas Gulf Coast regions, higher salt water disposal expenses and higher utility expenses. In addition, our production taxes increased as the result of higher commodity prices in 2005 and higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased primarily due to the lower production volumes mentioned above and higher production costs mentioned above.

Other. General and administrative costs are allocated to each business segment. The allocation is based on the estimated level of effort devoted to each segment s operations and the relative size of its EBIT, gross property and payroll as compared to the consolidated totals. During the quarter and six months ended June 30, 2005, the Production segment was allocated higher costs than the same periods in 2004, primarily due to an increase in benefits accrued under retirement plans and higher legal, insurance and professional fees. In addition, the Production segment was allocated a larger percentage of our total corporate costs due to the significance of its asset base and earnings to our overall asset base and earnings. In addition, capitalized overhead costs were lower in 2005 when compared to the same periods in 2004. The cost per unit of general and administrative expenses increased due to a combination of higher costs and lower production volumes discussed above. The decrease in other operating expenses for the six months periods related to employee severance expenses of $2 million in 2005 compared with $11 million in 2004.

Non-regulated Business Marketing and Trading Segment

Our Marketing and Trading segment s operations focus on the marketing of our natural gas production and the management of our remaining trading portfolio. Our Marketing and Trading segment s portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. We continue to consider opportunities to assign, terminate or otherwise accelerate the liquidation of certain of our legacy trading positions which may result in future losses. For a further discussion of the business activities and portfolio composition of our Marketing and Trading segment, see pages 118 through 119.

Significant factors impacting or occurring in the six months ended June 30, 2005:

Increases in natural gas prices continue to have an overall negative impact on the fair value of our natural gas and power derivatives, which generally require us to supply natural gas and power at fixed prices. In addition, natural gas prices increased more than power prices, which negatively impacted the fair value of our Cordova tolling agreement.

Effective April 1, 2005 we began using new forward pricing data provided by Platts Research and Consulting, our independent pricing source, due to their decision to discontinue the publication of the pricing data we had been utilizing in prior periods. In addition, due to the nature of the new forward pricing data, we extended the use of that data over the entire contractual term of our derivative contracts. Previously, we only used Platts pricing data to value our derivative contracts beyond two years. Based on our analysis, we do not believe the overall impact of this change in estimate was material to our results for the period.

Operating Results

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$ (21)	$ (141)	$ (196)	$ (300)
Operating expenses	(11)	(13)	(22)	(29)
Operating loss	(32)	(154)	(218)	(329)
Other income	2	2	3	13
EBIT	$ (30)	$ (152)	$ (215)	$ (316)
Gross margin by significant contract type:				
Natural gas contracts				
Production-related and other natural gas derivatives				
Changes in fair value on positions designated as hedges in December 2004	$	$ (104)	$	$ (260)
Changes in fair value on production-related contracts	(12)		(118)	
Changes in fair value on other natural gas positions	93	13	119	8
Total production-related and other natural gas derivatives	81	(91)	1	(252)
Transportation-related contracts				
Demand charges	(40)	(40)	(79)	(79)
Settlements	21	26	48	47
Total transportation-related contracts	(19)	(14)	(31)	(32)
Total gross margin natural gas contracts	62	(105)	(30)	(284)
Power contracts				
Changes in fair value on Cordova tolling agreement	(78)	(18)	(111)	(3)
Changes in fair value on other power derivatives	(22)	(18)	(72)	(13)
Favorable resolution of bankruptcy claim	17		17	
Total gross margin power contracts	(83)	(36)	(166)	(16)
Total gross margin	$ (21)	$ (141)	$ (196)	$ (300)

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

Listed below is a discussion of factors, by significant contract type, that affected the profitability of this segment during the quarters and six months ended June 30, 2005 and 2004:

Natural Gas Contracts

Production-related and other natural gas derivatives

Derivatives designated as hedges. The amounts in the above table represent changes in the fair values of derivative contracts that were designated as accounting hedges of our Production segment s natural gas production on December 1, 2004. Losses for the quarter and six months ended June 30, 2004 were a result of increases in natural gas prices relative to the fixed prices in these contracts. Following the designation of these derivatives as accounting hedges in the fourth quarter of 2004, we began reflecting the income impacts of these contracts in our Production segment.

Other production-related derivatives. We hold several option contracts that provide price protection on a portion of our Production segment s anticipated natural gas and oil production. These contracts, which are not accounting hedges and are marked to market in our results each period, provide El Paso with the following floor and ceiling prices on our future natural gas and oil production:

	2005	2006	2007
Natural Gas Options Held at June 30, 2005			
Volumes with Floor Price (TBtu)	36	120	30
Floor Price (per MMBtu)	$6.00	$7.00[1]	$6.00
Volumes with Ceiling Price (TBtu)		60	
Ceiling Price (per MMBtu)		$9.50	

	2007	2008	2009
Positions Added in July 2005[2]			
Natural Gas Options			
Volumes (TBtu)	21	18	17
Floor Price (per MMBtu)	$7.00	$6.00	$6.00
Ceiling Price (per MMBtu)	$9.00	$10.00	$8.75
Oil Options			
Volumes (MBbls)	1,009	930	
Floor Price (per Bbl)	$55.00	$55.00	
Average Ceiling Price (per Bbl)	$60.38	$57.03	

(1) In July 2005, we paid a net premium of $30 million to raise the floor price on these contracts from $6.00 per MMBtu.

(2) We entered into these positions related to our announced acquisition of Medicine Bow Energy Corporation.

In addition to the options described above, we hold several derivative contracts that, on a net basis, obligate us to sell natural gas at fixed prices on 3 TBtu of our Production segment s anticipated 2005 and 2006 natural gas production. The fair value of these production-related fixed price contracts and option contracts held at June 30, 2005 in the table above decreased by $12 million and $118 million during the quarter and six months ended June 30, 2005, due to increasing natural gas prices. In July 2005, we entered into several derivative contracts that obligate us to sell

34 TBtu of natural gas and 1,453 MBbls of oil at fixed prices related to the anticipated 2005 and 2006 natural gas and oil production from our announced acquisition of Medicine Bow.

Other natural gas derivatives. Other natural gas derivatives consist of physical and financial natural gas contracts that impact our earnings as the fair value of these contracts change. These contracts obligate us to either purchase or sell natural gas at fixed prices. Our exposure to natural gas price changes will vary from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Under certain of these contracts, we supply gas to power plants that we partially own. Due to their affiliated nature, we do not currently recognize mark-to-market gains or losses on these contracts to the extent of our ownership interests in the plants. However, should we sell our interests in these plants, we would be required to record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $106 million as of June 30, 2005, net of related hedges.

Transportation-related contracts

Demand charges paid on our Alliance pipeline capacity contract were $16 million and $32 million in the quarter and six months ended June 30, 2005, versus $15 million and $30 million in the same periods of 2004. Our ability to use our Alliance pipeline capacity contract was relatively consistent during these periods, allowing us to recover approximately 66 percent of our demand charges in the first six months of 2005 and 65 percent in the first six months of 2004. This resulted from the price differentials between the receipt and delivery points remaining relatively consistent during these periods.

Demand charges paid on our Texas Intrastate and remaining transportation contracts were $24 million and $47 million in the quarter and six months ended June 30, 2005, versus $25 million and $49 million in the same periods of 2004. Our ability to use the capacity under our Texas intrastate contracts improved in 2005 due to increased price differentials between the receipt and delivery points for the contracts. This allowed us to recover approximately 61 percent of the demand charges in the first six months of 2005 compared to only 18 percent during the same period in 2004. However, we only recovered 62 percent of the demand charges on our other transportation contracts in 2005 as compared to 70 percent in 2004, as price differentials between receipt and delivery points for these contracts decreased during the first six months of 2005.

Power Contracts

Cordova tolling agreement

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. During 2005 and 2004, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract.

Other power derivatives

During the first quarter of 2005, we assigned our contracts to supply power to our Power segment s Cedar Brakes I and II entities to Constellation Energy Commodities Group, Inc. These contracts decreased in fair value by $15 million and $38 million in the quarter and six months ended June 30, 2004. In conjunction with the transfer, we also entered into derivative contracts with Constellation that swap the locational differences in power prices at the Camden, Bayonne and Newark Bay power plants and the Pennsylvania-New Jersey-Maryland power pool s West Hub through 2013. The fair value of these swaps decreased by $6 million and $13 million during the quarter and six months ended June 30, 2005, due to unfavorable changes in the power prices at each location.

We have a contract to supply power to Morgan Stanley at a fixed price through 2016. This contract increased in fair value by less than $1 million and $10 million during the quarters ended June 30, 2005 and 2004, and decreased in fair value by $90 million and $45 million during the six months ended June 30, 2005 and 2004. The overall decrease in the fair value of these derivatives during the six months ended June 30, 2005 and 2004 resulted from increasing power prices related to these obligations during these periods. However prices during the second quarters of 2005 and 2004 decreased.

During the six months ended June 30, 2005 and 2004, we were required to purchase power under remaining power contracts, which include those used to manage the risk associated with our other power supply obligations. Due to changes in power prices, the fair value of these contracts decreased by $16 million and increased by $31 million during the quarter and six months ended June 30, 2005, and decreased by $13 million and increased by $70 million during the same periods of 2004.

On March 24, 2005, a bankruptcy court entered an order allowing Mohawk River Funding III s (MRF III) bankruptcy claims with USGen New England. We received payment on this claim and recognized a gain of $17 million for amounts received in excess of receivables previously recorded.

Operating Expenses

Operating expenses were relatively consistent for the quarters and six months ended June 30, 2005 and 2004. We recorded a $1 million loss in 2005 related to additional payments delayed by the Berkshire power plant under their fuel supply agreement. Berkshire is no longer able to delay any future payments under this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future deliveries are not paid for under this agreement because of Berkshire s inability to generate adequate cash flows and the uncertainty surrounding negotiations with their lenders. See Notes to Condensed Consolidated Financial Statements, Note 14 on page F-32 for additional information on this fuel supply agreement.

Non-regulated Business Power Segment

As of June 30, 2005, our Power segment primarily consisted of an international power business. Historically, this segment also included domestic power plant operations and a domestic power contract restructuring business. We have sold substantially all of these domestic businesses. Our ongoing focus within the Power segment will be to maximize the value of our assets in Brazil. Our other international power operations are considered non-core activities, and we expect to exit these activities within the next twelve months.

Significant developments in our operations that occurred since December 31, 2004 include:

Brazil. Our Macae project in Brazil has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras has not paid amounts due under the contract for December 2004 through the second quarter of 2005 and has initiated arbitration proceedings related to that obligation. For a further discussion of this matter, see Item 1, Financial Statements, Note 10. As a result of continued negotiations and discussions with Petrobras regarding this dispute, we recorded an impairment of this investment in the second quarter of 2005. This impairment was based on information regarding the potential value we would receive from the resolution of this matter. The future financial performance of the Macae plant will be affected by the ultimate outcome of this dispute, the timing of that outcome, and by regional changes in the Brazilian power markets.

Asia. During the second and third quarters of 2005, we announced the sale of substantially all of our Asian power assets. We recorded impairments on certain of these assets based on information received regarding the potential value we may receive when we sell them. In July 2005, we completed the sale of our 50 percent interest in the KIECO power facility in Korea. The sale resulted in a gain of $109 million, which will be recorded in the third quarter of 2005. We expect to receive total proceeds of approximately $180 million from the sale of our remaining Asian assets, which we expect will be substantially completed by the end of 2005. We will continue to assess the fair value of those assets throughout the sales process, which may result in additional impairments or gains in future periods.

Other International Power. During the second quarter of 2005, we engaged an investment banker to facilitate the sale of our Central American power assets. We recorded an impairment in the second quarter of 2005 based on information received about the value we may receive upon the sale of these assets. We will continue to assess the value of these assets throughout the sales process, which may result in additional impairments that may be significant. See Notes to Condensed Consolidated Financial Statements, Note 3 on page F-11 for further information on our divestitures.

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Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$ 101	$ 194	$ 160	$ 354
Operating expenses				
Loss on long-lived assets	(361)	(16)	(388)	(256)
Other operating expenses	(97)	(122)	(167)	(246)
Operating loss	(357)	56	(395)	(148)
Earnings from unconsolidated affiliates				
Impairments, net of gains on sale	(87)	(15)	(148)	(38)
Equity in earnings	28	39	61	78
Other income	35	22	51	41
EBIT	$ (381)	$ 102	$ (431)	$ (67)

(1) Gross margin for our Power segment consists of revenues from our power plants and the revenues, cost of electricity purchases and changes in fair value of restructured power contracts. The cost of fuel used in the power generation process is included in operating expenses.

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	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
EBIT by Area:				
Brazil				
Impairments	$ (294)	$	$ (294)	$ (151)
Earnings from consolidated and unconsolidated plant operations	12	50	26	106
Asia and Other International Power				
Impairments, net[1]	(161)		(258)	(5)
Dividend on investment fund	16		16	
Gain on sale of PPN power plant			22	
Earnings from consolidated and unconsolidated plant operations	11	20	31	36
Domestic Power				
Power Contract Restructurings:				
Favorable resolution of bankruptcy claim	53		53	
Impairments, net[1]				(96)
Change in fair value of contracts	1	39	11	58
Other Domestic Operations	(10)	2	(8)	6
Other[2]	(9)	(9)	(30)	(21)
EBIT	$ (381)	$ 102	$ (431)	$ (67)

(1) Includes impairment charges and gains (losses) on sales of assets and investments, net of any related minority interest.

(2) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance and engineering costs. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations. Other also includes gains and losses associated with our power turbine inventory. During the first quarter of 2005, we recorded a $15 million impairment of those turbines based on the receipt of further information about their fair value.

Brazil. In addition to the Macae impairment of $294 million, during the quarter and six months ended June 30, 2005 we did not recognize approximately $54 million and $99 million of our proportionate share of Macae s revenues based on non-payment of these amounts by Petrobras, which significantly affected our earnings at the plant. Partially offsetting the decline in Macae s earnings were lower insurance and general and administrative costs associated with our Brazilian operations. During the first quarter of 2004, we recorded an impairment of our Manaus and Rio Negro power plants based on the status of our negotiations to extend the power contracts, which was negatively impacted by changes in the Brazilian political environment.

Asia and Other International Power. During the second quarter of 2005, we recorded a $111 million impairment, net of related minority interest, on our Central American power assets and a $34 million impairment on our Asian assets. We also recorded $16 million of impairments, net of gains on sales, primarily related to our investments in power plants in Peru, England and Hungary based on the sale or anticipated sale of these projects. In the first quarter of 2005, we also recorded $97 million of impairments, which was primarily associated with our Asian assets based on ongoing sales negotiations.

In addition to these impairments, we did not recognize approximately $8 million and $19 million of our proportionate share of earnings for the quarter and six months ended June 30, 2005 on our Asian power investments since we did not believe these amounts could be realized. In a separate transaction, we also sold our interest in a power plant in India, which had previously been fully impaired. This sale resulted in a gain of $22 million in the first quarter of 2005.

Domestic Power Contract Restructurings. On March 24, 2005, a bankruptcy court entered an order allowing MRF III s bankruptcy claims with USGen New England. In June 2005, we received payment on this claim and recognized a gain of $53 million for amounts received in excess of receivables previously recorded.

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With the completion of the sale of Cedar Brakes I and II in March 2005, we have sold substantially all of our domestic power contract restructuring business. As a result, in 2005, there was a substantial reduction in activity in these operations compared to changes in the fair value of these contracts that occurred during 2004. Our remaining operations include derivative contracts and related debt in Mohawk River Funding II (MRF II). We are currently evaluating opportunities to sell our interest in MRF II and our related power supply contracts, which may result in future losses. During the first quarter of 2004, we recorded a loss of $98 million related to the announced sale of Utility Contract Funding and its restructured power contract and related debt.

Other Domestic Operations. Our other domestic operations include:

MCV. In 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. During the quarter ended June 30, 2005, we recorded a further impairment of $4 million based on a decrease in the fair value of the investment due to delays in the timing of expected cash flow receipts from this investment. After eliminating affiliated transactions, our proportionate share of MCV s reported losses during the second quarter of 2005 was $14 million and our proportionate share of their earnings during the six months ended June 30, 2005 was $58 million. A significant portion of these earnings (losses) related to mark-to-market changes recorded by MCV on their unaffiliated fuel supply contracts. We determined that these fair value changes did not increase or decrease the fair value of our equity investment and could not be realized in the future. Accordingly, we decreased our proportionate share of MCV s losses by $14 million during the second quarter of 2005 and decreased our proportionate share of their earnings by $57 million during the six months ended June 30, 2005. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

Other Domestic Assets. During the quarter and six months ended June 30, 2004, we recorded earnings from consolidated and unconsolidated affiliates of approximately $41 million and $48 million and impairments of approximately $34 million and $45 million on our domestic power plants to adjust their book value to their estimated sales proceeds.

Non-regulated Business Field Services Segment

Our Field Services segment has historically conducted our midstream activities. In 2004, these activities included our gathering and processing operations in south Texas and south Louisiana and our general and limited partner interests in GulfTerra and Enterprise. In January 2005, we sold our remaining common units and interest in the general partner of Enterprise and our interests in the Indian Springs natural gas gathering and processing assets to Enterprise. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which we have reclassified as discontinued operations for the quarter and six months ended June 30, 2005. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

For the quarter and six months ended June 30, 2005, EBIT in our Field Services segment was a loss of $3 million and earnings of $179 million as compared to earnings of $27 million and $63 million during the same periods of 2004 due to the following:

	Favorable (unfavorable) EBIT impact for the quarter ended June 30, 2005 compared to 2004	Favorable (unfavorable) EBIT impact for the six months ended June 30, 2005 compared to 2004
Gathering and processing margins	$ (37)	$ (79)
Operating expenses	25	59
Gain on sale of GP interest and common units to Enterprise		183
Other equity earnings	(30)	(68)
Minority interest	11	22
Other	1	(1)
Total increase (decrease) in EBIT	$ (30)	$ 116

During the quarter and six months ended June 30, 2005, we experienced a significant decrease in our gathering & processing operations as compared to the same period in 2004, primarily as a result of asset sales.

For a discussion of our historical ownership interests in Enterprise and activities with the partnership, see Notes to Condensed Consolidated Financial Statements, Note 14 on page F-32. For a discussion of our discontinued operations associated with our gathering and processing assets, see Notes to Condensed Consolidated Financial Statements Note 3, on page F-11. For a further discussion of the historical business activities of our Field Services segment, see page 122.

Corporate, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, all of which are immaterial to our results in 2005.

For the quarter and six months ended June 30, 2005, EBIT in our corporate operations was lower than the same periods in 2004 due to the following:

	Favorable (unfavorable) EBIT impact for quarter ended June 30, 2005 compared to 2004	Favorable (unfavorable) EBIT impact for six months ended June 30, 2005 compared to 2004
	(In millions)	

Western Energy Settlement charge in 2005[1]	$		$	(59)
Losses on early extinguishment of debt in 2005				(29)
Lease termination costs due to office consolidation		(27)		(27)
Change in litigation, insurance and other reserves		(1)		(16)
Other		7		(7)
Total decrease in EBIT	$	(21)	$	(138)

(1) In the first quarter of 2005, we incurred this $59 million charge associated with the payment of the Western Energy Settlement obligation earlier than originally expected. This charge has been recorded in operations and maintenance expense.

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. In all of our legal and insurance matters, we evaluate each suit and claim as to its merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results.

As discussed in Notes to Condensed Consolidated, Financial Statements, Note 4, on page F-14 we had an accrual as of December 31, 2004 related to our remaining lease obligations associated with the consolidation of our Houston-based operations. Our estimated costs were based on a discounted liability, which included estimates of future sublease rentals. During the quarter and six months ended June 30, 2005, we recorded additional charges of $17 million related to vacating this remaining leased space to our downtown Houston location. In June 2005, we signed a termination agreement related to this lease obligation, which resulted in an additional charge of $10 million.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2005, was $70 million and $143 million lower than the same periods in 2004. Below is an analysis of our interest expense for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Long-term debt, including current maturities	$ 331	$ 391	$ 675	$ 795
Other	9	19	15	38
Total interest and debt expense	$ 340	$ 410	$ 690	$ 833

During the quarter and six months ended June 30, 2005, our total interest and debt expense decreased primarily due to the retirements of long-term debt and other financing obligations (net of issuances) during 2005 and 2004. See Notes to Condensed Consolidated Financial Statements, Note 9, on page F-17 for a further discussion of our activities related to debt repayments and issuances.

Income Taxes

Income taxes included in our income (loss) from continuing operations and our effective tax rates for the period ended June 30 were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions, except for rates)			
Income taxes	$ (51)	$ 48	$ (57)	$ 58
Effective tax rate	18%	59%	30%	(215)%

For a discussion of our effective tax rates, see Notes to Condensed Consolidated Financial Statements, Note 6 on page F-15.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has indicated that additional guidance for applying the repatriation provisions of the American Jobs Creation Act of 2004 will be issued. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act of 2004, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

Discontinued Operations

We have petroleum markets operations, international natural gas and oil production operations outside of Brazil, and gathering and processing operations in south Louisiana that are classified as discontinued operations in our financial statements. Our south Louisiana gathering and processing assets were approved for sale by our Board of Directors during the second quarter of 2005. Accordingly, these assets and the results of their operations for the quarter and six months ended June 30, 2005, have been reclassified as discontinued operations. Prior period amounts have not been adjusted as these operations did not materially impact prior period results or historical trends.

The loss from our discontinued operations for the second quarter of 2005 was $5 million compared to a loss of $29 million for the same period in 2004. The loss in 2005 consisted of losses of $11 million in our petroleum markets and international production operations and income of $6 million in our south Louisiana gathering and processing operations. The loss in 2004 consisted of losses of $14 million in our petroleum markets operations and $15 million in our international production operations.

The loss from our discontinued operations for the six months ended June 30, 2005 was $1 million compared to a loss of $106 million for the same period in 2004. The loss in 2005 consisted of losses of $13 million in our petroleum markets and international production operations and income of $12 million in our south Louisiana gathering and processing operations. The loss in 2004 consisted of losses of $77 million in our petroleum markets operations, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs and $29 million of losses in our international production operations, primarily from impairments and losses on sales.

Commitments and Contingencies

See Notes to Condensed Consolidated, Financial Statements, Note 10, on page F-19.

Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed on pages 69 to 72.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported on pages 69 to 72, except as presented below:

Market Risk

We are exposed to a variety of market risks in the normal course of our business activities, including commodity price, foreign exchange and interest rate risks. We measure risks on the derivative and non-derivative contracts in our trading portfolio on a daily basis using a Value-at-Risk model. We measure our Value-at-Risk using a historical simulation technique, and we prepare it based on a confidence level of 95 percent and a one-day holding period. This Value-at-Risk was $25 million as of June 30, 2005 and $16 million as of December 31, 2004, and represents our potential one-day unfavorable impact on the fair values of our trading contracts.

Interest Rate Risk

As of June 30, 2005 and December 31, 2004, we had $60 million and $665 million of third party long-term restructured power derivative contracts. In March 2005, we sold Cedar Brakes I and II, which held two power derivative contracts with a combined fair value of $596 million as of December 31, 2004. This sale substantially reduced our exposure to interest rate risks.

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BUSINESS

We are an energy company originally founded in 1928 in El Paso, Texas. For many years, we served as a regional natural gas pipeline company conducting business mainly in the western United States. From 1996 through 2001, we expanded to become an international energy company through a number of mergers, acquisitions and internal growth initiatives. By 2001, our operations expanded to include natural gas production, power generation, petroleum businesses, trading operations and other new ventures and businesses, in addition to our traditional natural gas pipeline businesses. During this period, our total assets grew from approximately $2.5 billion at December 31, 1995 to over $44 billion following the completion of The Coastal Corporation merger in January 2001. During this same time period, we incurred substantial amounts of debt and other obligations.

In late 2001 and in 2002, our industry and business were adversely impacted by a number of significant events, including (i) the bankruptcy of a number of energy sector participants, (ii) the general decline in the energy trading industry, (iii) performance in some areas of our business that did not meet our expectations, (iv) credit rating downgrades of us and other industry participants and (v) regulatory and political pressures arising out of the western energy crisis of 2000 and 2001.

These events adversely affected our operating results, our financial condition and our liquidity during 2002 and 2003. During this two year period, we refocused on our natural gas assets and divested or otherwise sold our interests in a significant number of assets, generating proceeds in excess of $6 billion. As a result of those sales activities and the performance of our businesses during this time period, we also experienced significant losses.

In late 2003 and early 2004, we appointed a new chief executive officer and several new members of the executive management team. Following a period of assessment, we announced that our long-term business strategy would principally focus on our core pipeline and production businesses. Our businesses are owned through a complex legal structure of companies that reflect the acquisitions and growth in our business from 1996 to 2001. As part of our long range strategy, we are actively working to reduce the complexity of our corporate structure, which is shown below in a condensed format, as of December 31, 2004.

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Business Segments

For the year ended December 31, 2004, we had both regulated and non-regulated operations conducted through five business segments Pipelines, Production, Marketing and Trading, Power and Field Services. Through these segments, we provided the following energy related services:

Regulated Operations Pipelines	Our interstate natural gas pipeline system is the largest in the U.S., and owns or has interests in approximately 56,000 miles of pipeline and approximately 420 Bcf of storage capacity. We provide customers with interstate natural gas transmission and storage services from a diverse group of supply regions to major markets around the country, serving many of the largest market areas.
Non-regulated Operations Production	Our production business holds interests in approximately 3.6 million net developed and undeveloped acres and had approximately 2.2 Tcfe of proved natural gas and oil reserves worldwide at the end of 2004. During 2004, our production averaged approximately 814 MMcfe/d.
Marketing and Trading	Our marketing and trading business markets our natural gas and oil production and manages our historical energy trading portfolio. During 2004, we continued to actively liquidate this historical trading portfolio.
Power	Our power business changed significantly during 2003 and 2004 with the sale of a substantial portion of our domestic power assets. As of December 31, 2004, we continued to own or manage approximately 10,400 MW of gross generating capacity in 16 countries. Our plants serve customers under long-term and market-based contracts or sell to the open market in spot market transactions. We have completed the sale of substantially all of our domestic contracted power assets and are either pursuing or evaluating the sale of many of our international assets.
Field Services	Our midstream or field services business provides processing and gathering services, primarily in south Louisiana. Through December 2004, we also owned a 9.9 percent interest in the general partner of Enterprise Products Partners L.P. (Enterprise), a large publicly traded master limited partnership, as well as a 3.7 percent limited partner interest in Enterprise. In January 2005, we sold all of our ownership interests in Enterprise and its general partner. We currently expect to sell many of our remaining Field Services assets.

During 2004, we also had discontinued operations related to a historical petroleum markets business and international natural gas and oil production operations, primarily in Canada.

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Under our long-term business strategy, we will continue to concentrate on our core pipeline and production businesses and activities that support those businesses while divesting or otherwise disposing of our ownership in non-core assets and operations. Our long-term strategy will focus on:

Business	Objective and Strategy
Pipelines	Protecting and enhancing asset value through successful recontracting, continuous efficiency improvements through cost management, and prudent capital spending in the U.S. and Mexico.
Production	Growing our production business in a way that creates shareholder value through disciplined capital allocation, cost leadership and superior portfolio management.
Marketing and Trading	Marketing and physical trading of our natural gas and oil production.
Power	Managing our remaining power generation assets to maximize value.
Field Services	Optimizing our remaining gathering and processing assets.

Below is a discussion of each of our business segments. Our business segments provide a variety of energy products and services. We managed each segment separately and each segment requires different technology and marketing strategies. For additional discussion of our business segments, see Management s Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and identifiable assets, see Notes to Consolidated Financial Statements, Note 21, on page F-105.

Regulated Business Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage, LNG terminalling and related services. We own or have interests in approximately 56,000 miles of interstate natural gas pipelines in the United States that connect the nation s principal natural gas supply regions to the six largest consuming regions in the United States: the Gulf Coast, California, the Northeast, the Midwest, the Southwest and the Southeast. These pipelines represent the nation s largest integrated coast-to-coast mainline natural gas transmission system. Our pipeline operations also include access to systems in Canada and assets in Mexico. We also own or have interests in approximately 420 Bcf of storage capacity used to provide a variety of flexible services to our customers and an LNG terminal at Elba Island, Georgia.

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Our Pipelines segment conducts its business activities primarily through (i) eight wholly owned and four partially owned interstate transmission systems, (ii) five underground natural gas storage entities and (iii) an entity that owns the Elba Island LNG terminalling facility.

Wholly Owned Interstate Transmission Systems

		As of December 31, 2004					
					Average Throughput(1)		
Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	2004	2003 (BBtu/d)	2002
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.	14,200	6,876	90	4,469	4,710	4,596
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,500	6,620	192	4,067	4,232	4,130
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.	11,000	5,650(2)		4,074	3,874	3,799

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		As of December 31, 2004			Average Throughput[(1)]		
			Design	Storage			
Transmission		Miles of	Capacity	Capacity		2003	
System	Supply and Market Region	Pipeline	(MMcf/d)	(Bcf)	2004	(BBtu/d)	2002
Southern Natural Gas (SNG)	Extends from 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.	8,000	3,437	60	2,163	2,101	2,151
Colorado Interstate Gas (CIG)	Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest.	4,000	3,000	29	1,744	1,685	1,687
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,997		1,201	1,213	1,194
Mojave Pipeline (MPC)	Connects with the EPNG and Transwestern transmission systems at Topock, Arizona, and the Kern River Gas Transmission Company transmission system in California, and extends to customers in the vicinity of Bakersfield, California.	400	400		161	192	266
Cheyenne Plains Gas Pipeline (CPG)	Extends from the Cheyenne hub in Colorado to various pipeline interconnects near Greensburg, Kansas.	400	396(3)		89		

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity reflects winter-sustainable west-flow capacity and 800 MMcf/d of east-end delivery capacity.

(3) This capacity was placed in service on December 1, 2004. Compression was added and placed in service on January 31, 2005, which increased the design capacity to 576 MMcf/d.

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We also have several pipeline expansion projects underway as of December 31, 2004 that have been approved by the Federal Energy Regulatory Commission (FERC), the more significant of which are presented below:

Transmission System	Project	Capacity	Description	Anticipated Completion Date
		(MMcf/d)		
ANR	East Leg Wisconsin expansion	142	To replace 4.7 miles of an existing 14-inch natural gas pipeline with a 30-inch line in Washington County, add 3.5 miles of 8-inch looping[(1)] on the Denmark Lateral in Brown County, and modify ANR s existing Mountain Compressor Station in Oconto County, Wisconsin.	November 2005
	North Leg Wisconsin expansion	110	To add 6,000 horsepower of electric- powered compression at ANR s Weyauwega Compressor station in Waupaca County, Wisconsin.	November 2005
CPG	Cheyenne Plains expansion	179	To add approximately 10,300 horsepower of compression and an additional treatment facility to the Cheyenne Plains project.	December 2005

(1) Looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases a transmission system s capacity.

Partially Owned Interstate Transmission Systems

		As of December 31, 2004					
					Average Throughput[(2)]		
Transmission System[(1)]	Supply and Market Region	Ownership Interest	Miles of Pipeline[(2)]	Design Capacity[(2)]	2004	2003	2002
		(Percent)		(MMcf/d)	(BBtu/d)		
Florida Gas Transmission[(3)]	Extends from south Texas to south Florida.	50	4,870	2,082	2,014	1,963	2,004
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,200	2,366	2,378
Samalayuca Pipeline and Gloria a Dios Compression Station	Extends from U.S./Mexico border to the State of Chihuahua, Mexico.	50	23	460	433	409	434
San Fernando Pipeline	Pipeline running from Pemex Compression Station 19 to	50	71	1,000	951	130	

Pemex metering station in San Fernando, Mexico in the State of Tamaulipas.

(1) These systems are accounted for as equity investments.
(2) Miles, volumes and average throughput represent the systems totals and are not adjusted for our ownership interest.
(3) We have a 50 percent equity interest in Citrus Corporation, which owns this system.

We also have a 50 percent interest in Wyco Development, L.L.C. Wyco owns the Front Range Pipeline, a state-regulated gas pipeline extending from the Cheyenne Hub to Public Service Company of Colorado s (PSCo) Fort St. Vrain electric generation plant, and compression facilities on WIC s Medicine Bow Lateral. These facilities are leased to PSCo and WIC, respectively, under long-term leases.

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Underground Natural Gas Storage Entities

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage entities:

	As of December 31, 2004		
Storage Entity	Ownership Interest	Storage Capacity[1]	Location
	(Percent)	(Bcf)	
Bear Creek Storage	100	58	Louisiana
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage[2]	50	13	Michigan
Young Gas Storage[2]	48	6	Colorado

(1) Includes a total of 133 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

(2) These systems were accounted for as equity investments as of December 31, 2004.

LNG Facility

In addition to our pipeline systems and storage facilities, we own an LNG receiving terminal located on Elba Island, near Savannah, Georgia. The facility is capable of achieving a peak sendout of 675 MMcf/d and a base load sendout of 446 MMcf/d. The terminal was placed in service and began receiving deliveries in December 2001. The current capacity at the terminal is contracted with a subsidiary of British Gas, BG LNG Services, LLC. In 2003, the FERC approved our plan to expand the peak sendout capacity of the Elba Island facility by 540 MMcf/d and the base load sendout by 360 MMcf/d (for a total peak sendout capacity once completed of 1,215 MMcf/d and a base load sendout of 806 MMcf/d). The expansion is estimated to cost approximately $157 million and has a planned in-service date of February 2006.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each of our pipeline systems and storage facilities operates under FERC-approved tariffs that establish rates, terms and conditions for services to our customers. Generally, the FERC s authority extends to:

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

certification and construction of new facilities;

extension or abandonment of facilities;

maintenance of accounts and records;

relationships between pipeline and energy affiliates;

terms and conditions of service;

depreciation and amortization policies;

- acquisition and disposition of facilities; and

- initiation and discontinuation of services.

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. Our revenues from transportation, storage, LNG terminalling and related services (transportation services revenues) consist of reservation revenues and usage revenues. Reservation revenues are from customers (referred to as firm customers) whose contracts (which are for varying terms) reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) who pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn. In 2004, approximately 84 percent of our transportation services revenues were attributable to reservation charges paid by firm customers. The remaining 16 percent of our transportation services revenues are variable. Due to our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the creditworthiness of our customers. We also experience volatility in our financial results when the amount of gas utilized in our operations differs from the amounts we receive for that purpose.

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations. Our systems have ongoing programs designed to keep our facilities in compliance with these safety and environmental requirements, and we believe that our systems are in material compliance with the applicable requirements.

Markets and Competition

We provide 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 and hydroelectric power for power generation and fuel oil for heating.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing the delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. These LNG delivery systems also may compete with our pipelines for transportation of gas into market areas we serve.

Electric power generation is the fastest growing demand sector of the natural gas market. The growth and development of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. The increase in natural gas prices, driven in part by increased demand from the power sector, has diminished the demand for gas in the industrial sector. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their creditworthiness.

Our existing contracts mature at various times and in varying amounts of throughput capacity. As our pipeline contracts expire, our ability to extend our existing contracts or re-market expiring contracted capacity is dependent on the 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 re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times and in certain regions, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. The table below shows the contracted capacity that expires by year over the next six years and thereafter.

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Contract Expirations

The following table details the markets we serve and the competition faced by each of our wholly owned pipeline systems as of December 31, 2004:

Transmission System	Customer Information	Contract Information	Competition
TGP	Approximately 432 firm and interruptible customers.	Approximately 464 firm contracts Weighted average remaining contract term of approximately five years.	TGP faces strong competition in the Northeast, Appalachian, Midwest and Southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and from the Canadian border.
	Major Customers: None of which individually represents more than 10 percent of revenues		
			In the offshore areas of the Gulf of Mexico, factors such as the distance of the supply field from the pipeline, relative basis pricing of the pipeline receipt options, costs of intermediate gathering or required processing of the gas all influence determinations of whether gas is ultimately attached to our system.

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Transmission System	Customer Information	Contract Information	Competition
ANR	Approximately 259 firm and interruptible customers	Approximately 570 firm contracts Weighted average remaining contract term of approximately three years.	In the Midwest, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast, ANR competes with other interstate pipelines serving electric generation and local distribution companies. ANR also competes directly with other interstate pipelines, including Guardian Pipeline, for markets in Wisconsin. We Energies owns an interest in Guardian, which is currently serving a portion of its firm transportation requirements. ANR also competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR s principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.
	Major Customer: We Energies (909 Bbtu/d)	Contract terms expire in 2005-2010.	
EPNG	Approximately 155 firm and interruptible customers	Approximately 213 firm contracts Weighted average remaining contract term of approximately five years [1][2].	EPNG faces competition in the West and Southwest from other existing pipelines, storage facilities, as well as alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
	Major Customer: Southern California Gas Company[2] (475 BBtu/d) (82 BBtu/d)	Contract terms expire in 2006. Contract terms expire in	

(768 BBtu/d)	2005 and 2007. Contract terms expire in 2009-2011.

(1) Approximately 1,564 MMcf/d currently under contract is subject to early termination in August 2006 provided customers give timely notice of an intent to terminate. If all of these rights were exercised, the weighted average remaining contract term would decrease to approximately three years.

(2) Reflects the impact of an agreement we entered into, subject to FERC approval, to extend 750 MMCf/d of SoCal s current capacity, effective September 1, 2006, for terms of three to five years.

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Transmission System	Customer Information	Contract Information	Competition
SNG	Approximately 230 firm and interruptible customers	Approximately 203 firm contracts Weighted average remaining contract term of approximately five years.	Competition is strong in a number of SNG s key markets. 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 many of its other customers.
	Major Customers:		
	Atlanta Gas Light Company (972 BBtu/d)	Contract terms expire in 2005-2007.	
	Southern Company Services (418 BBtu/d)	Contract terms expire in 2010-2018.	
	Alabama Gas Corporation (415 BBtu/d)	Contract terms expire in 2006-2013.	
	Scana Corporation (346 BBtu/d)	Contract terms expire in 2005-2019.	
CIG	Approximately 112 firm and interruptible customers	Approximately 191 firm contracts Weighted average remaining contract term of approximately five years.	CIG serves two major markets. Its on- system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its 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 for its on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for its off-system market consists of other interstate pipelines that are directly connected to its supply sources.
	Major Customers:		
	Public Service Company of Colorado (970 BBtu/d)	Contract term expires in 2007.	
	(261 BBtu/d)	Contract term expires in 2009-2014.	
	(187 BBtu/d)	Contract term expires in 2006.	

WIC	Approximately 49 firm and interruptible customers	Approximately 47 firm contracts Weighted average remaining contract term of approximately six years.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC s one Bcf/d Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply and can readily be expanded as supply increases. Currently, there are two other interstate pipelines that transport limited volumes out of this basin.
	Major Customers:		
	Williams Power Company (303 BBtu/d)	Contract terms expire in 2008-2013.	
	Colorado Interstate Gas Company (247 BBtu/d)	Contract terms expire in 2005-2016.	
	Western Gas Resources (235 BBtu/d)	Contract terms expire in 2007-2013.	
	Cantera Gas Company (226 BBtu/d)	Contract terms expire in 2012-2013.	

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Transmission System	Customer Information	Contract Information	Competition
MPC	Approximately 14 firm and interruptible customers	Approximately nine firm contracts Weighted average remaining contract term of approximately two years.	MPC faces competition from existing pipelines, a newly proposed pipeline, LNG projects and alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
	Major Customers:		
	Texaco Natural Gas Inc. (185 BBtu/d)	Contract term expires in 2007.	
	Burlington Resources Trading Inc. (76 BBtu/d)	Contract term expires in 2007.	
	Los Angeles Department of Water and Power (50 BBtu/d)	Contract term expires in 2007.	
CPG	Approximately 15 firm and interruptible customers.	Approximately 14 firm contracts Weighted average remaining contract term of approximately 10 years.	Cheyenne Plains competes directly with other interstate pipelines serving the Mid-continent region. Indirectly, Cheyenne Plains competes with other interstate pipelines that transport Rocky Mountain gas to other markets.
	Major Customers:		
	Oneok Energy Services Company L.P. (195 BBtu/d)	Contract term expires in 2015.	
	Anadarko Energy Service Company (100 BBtu/d)	Contract term expires in 2015.	
	Kerr McGee (83 BBtu/d)	Contract term expires in 2015.	

Non-regulated Business Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in the United States and Brazil. In the United States, as of December 31, 2004, we controlled over 3 million net acres of leasehold acreage through our operations in 20 states, including Louisiana, New Mexico, Texas, Oklahoma, Alabama and Utah, and through our offshore operations in federal and state waters in the Gulf of Mexico. During 2004, daily equivalent natural gas production averaged approximately 814 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2004, were approximately 2.2 Tcfe.

As part of our long-term business strategy we will focus on developing production opportunities around our asset base in the United States and Brazil. Our operations are divided into the following areas:

Area	Operating Regions
United States	
Onshore	Black Warrior Basin in Alabama
	Arkoma Basin in Oklahoma
	Raton Basin in New Mexico
	Central (primarily in north Louisiana)
	Rocky Mountains (primarily in Utah)
Texas Gulf Coast	South Texas
Offshore and south Louisiana	Gulf of Mexico (Texas and Louisiana)
	South Louisiana
Brazil	Camamu, Santos, Espirito Santos and Potiguar Basins

In Brazil, we have been successful with our drilling programs in the Santos and Camamu Basins and are pursuing gas contracts and development options in these two basins. In July 2004, we acquired the remaining 50 percent interest we did not own in UnoPaso, a Brazilian oil and gas company. While we intend to work with

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Petrobras, a Brazilian national energy company, in growing our presence in the Potiguar Basin with increased production and planned exploratory activity, disputes with them in other areas of our business may impact our plans.

Natural Gas, Oil and Condensate and Natural Gas Liquids Reserves

The tables below detail our proved reserves at December 31, 2004. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott was within four percent of our internally prepared estimates presented in these tables. This information is 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. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our proved properties based on value. The tables below exclude our Power segment s equity interests in Sengkang in Indonesia and Aguaytia in Peru. Combined proved reserves balances for these interests were 132,336 MMcf of natural gas and 2,195 MBbls of oil, condensate and natural gas liquids (NGL) for total natural gas equivalents of 145,507 MMcfe, all net to our ownership interests. Our estimated proved reserves as of December 31, 2004, and our 2004 production are as follows:

Net Proved Reserves(1)

	Natural Gas	**Oil/ Condensate**	**NGL**	**Total**		**2004 Production**
	(MMcf)	**(MBbls)**	**(MBbls)**	**(MMcfe)**	**(Percent)**	**(MMcfe)**
United States						
Onshore	1,100,681	14,675	1,233	1,196,133	55	84,568
Texas Gulf Coast	431,508	3,118	9,874	509,454	23	103,286
Offshore and south Louisiana	191,652	9,538	2,094	261,444	12	101,140
Total United States	1,723,841	27,331	13,201	1,967,031	90	288,994
Brazil	68,743	24,171		213,769	10	8,772
Total	1,792,584	51,502	13,201	2,180,800	100	297,766

(1) 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.

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The table below summarizes our estimated proved producing reserves, proved non-producing reserves, and proved undeveloped reserves as of December 31, 2004:

Net Proved Reserves[1]

	Natural Gas	Oil/ Condensate	NGL	Total	
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(Percent)
United States					
Producing	1,085,581	12,507	10,588	1,224,152	62
Non-Producing	201,696	7,134	1,355	252,626	13
Undeveloped	436,564	7,690	1,258	490,253	25
Total proved	1,723,841	27,331	13,201	1,967,031	100
Brazil					
Producing	29,239	1,375		37,488	18
Non-Producing	24,988	1,238		32,415	15
Undeveloped	14,516	21,558		143,866	67
Total proved	68,743	24,171		213,769	100
Worldwide					
Producing	1,114,820	13,882	10,588	1,261,640	58
Non-Producing	226,684	8,372	1,355	285,041	13
Undeveloped	451,080	29,248	1,258	634,119	29
Total proved	1,792,584	51,502	13,201	2,180,800	100

(1) 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.

Recovery of proved undeveloped 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 proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of reasonable certainty be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. 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. For further discussion of our reserves, see Supplemental Financial Information, under the heading Supplemental Natural Gas and Oil Operations (Unaudited), on page F-126.

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Acreage and Wells

The following table details our gross and net interest in developed and undeveloped acreage at December 31, 2004. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
United States						
Onshore	1,032,115	419,789	1,653,540	1,308,491	2,685,655	1,728,280
Texas Gulf Coast	199,035	82,850	257,225	172,340	456,260	255,190
Offshore and south Louisiana	643,861	448,599	744,957	697,515	1,388,818	1,146,114
Total	1,875,011	951,238	2,655,722	2,178,346	4,530,733	3,129,584
Brazil	39,476	13,817	1,346,919	452,552	1,386,395	466,369
Worldwide Total	1,914,487	965,055	4,002,641	2,630,898	5,917,128	3,595,953