EL PASO CORP/DE
Form POS AM
August 10, 2005

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As filed with the Securities and Exchange Commission on August 10, 2005
Registration No. 333-82412

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Post-Effective Amendment No. 2 to Form S-3
on
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: August 16, 2005

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

This Registration Statement on Form S-1 constitutes a post-effective amendment to the Company s Registration Statement on Form S-3 (Registration No. 333-82412). The Company is filing this post-effective amendment for the purpose of meeting the requirements of Section 10(a)(3) of the Securities Act of 1933. Pursuant to Rule 401(b) under the Securities Act, the Company is filing this post-effective amendment on Form S-1, as it is currently ineligible to file a registration statement on Form S-3.

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. Although we are permitted by United States Federal Securities Laws to offer these securities using this prospectus, we may not sell them 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 10, 2005

PROSPECTUS

13,639,403 Shares
El Paso Corporation
Common Stock

We issued 11,500,000 of our 9.00% equity security units in June 2002, of which 5,442,040 equity security units remain outstanding. Each equity security unit has a stated amount of $50 and consists of (a) a purchase contract which obligates the holder to purchase from us, at a purchase price of $50, shares of our common stock on August 16, 2005 and (b) a senior note with a principal amount of $50 that is due on August 16, 2007. The senior note was initially pledged by us to secure the holders obligation to purchase shares of our common stock under the purchase contract. Based upon the current terms of the purchase contracts, a maximum of approximately 13,639,403 shares of our common stock will be issued upon settlement of the purchase contracts. This prospectus covers the shares of common stock issuable upon maturity or early settlement of the purchase contracts.

Our common stock is listed on the New York Stock Exchange under the symbol EP. On August 9, 2005, the last reported sale price of our common stock on the NYSE was $11.83 per share.

The equity security units are listed on the NYSE under the symbol EP PrA.

Investing in our common stock involves risk. Please read Risk Factors beginning on page 4.

Neither the SEC nor any state securities commission has approved or disapproved of these securities 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.

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Consent of Ryder Scott Company, L.P.

EXPLANATORY NOTE

On June 26, 2002 we issued 11,500,000 equity security units, or ESUs, of which 5,442,040 ESUs are currently issued and outstanding. Each ESU originally consisted of (a) a purchase contract which obligates the holder to purchase from us, at a purchase price of $50, shares of our common stock on August 16, 2005 and (b) a senior note with a principal amount of $50 that is due on August 16, 2005. In July 2005, the senior notes were successfully remarketed. The remarketed notes carry an interest rate of 7.625% and mature on August 16, 2007. The issuance of the ESUs, and the issuance pursuant to the purchase contracts of the shares of our common stock on August 16, 2005 or upon the early settlement of the purchase contracts, was originally registered under a shelf registration statement on Form S-3 (Common File No. 333-82412). Due to the late filing of our Annual Report on Form 10-K for the year ended December 31, 2003, under applicable SEC rules we no longer qualify for the use of a registration statement on Form S-3 or for incorporation of information by reference into a prospectus. In order to assure that shares of our common stock issued upon maturity or early settlement of the purchase contracts are so issued under an effective registration statement, we have filed a post-effective amendment on Form S-1 to the registration statement described above. This prospectus is a part of that post-effective amendment and registers the issuance of the shares of our common stock upon the maturity of the purchase contracts on August 16, 2005 or early settlement of such purchase contracts. As we no longer qualify for incorporation of information by reference under applicable SEC rules, no information is incorporated in this prospectus by reference.

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

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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.

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.

When we refer to us, we, our, ours, or El Paso, we are describing El Paso Corporation and/or our subsidiarie

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

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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.

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.

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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 4 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 purchase contracts and the common stock issuable upon settlement 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 common stock subject to issuance upon settlement of the purchase contracts, as well as the other considerations that are important to you in making your investment decision. You should pay special attention to the Risk Factors beginning on page 4 of this prospectus and the section entitled Cautionary Statement Regarding Forward-Looking Statements on page iv of this prospectus. For purposes of this prospectus, except where we are describing the terms of the ESUs, purchase contracts and the common stock subject to issuance upon settlement 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, toge its subsidiaries. With respect to any description of the terms of the common stock subject to issuance upon settlement of the purchase contracts, 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 93.

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

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

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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 93 of this prospectus.

The Offering and this Prospectus

This prospectus relates to the shares of our common stock to be issued upon the maturity on August 16, 2005 or early settlement of the purchase contracts originally issued in connection with our public offering of ESUs on June 26, 2002. The number of shares of our common stock issuable upon settlement of the purchase contract will be (1) 2.0886 shares per purchase contract in the case of early settlement, subject to adjustment upon specified events, or (2) in the case of shares issuable upon maturity of the purchase contracts, will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to August 16, 2005. The settlement rate will range from 2.0886 shares to 2.5063 shares per purchase contract with the actual rate to be determined based on such average price, subject to adjustment upon specified events. Accordingly, currently we will issue a minimum of approximately 11.4 million shares and up to a maximum of approximately 13.6 million shares on the settlement date of the purchase contracts, depending on our average stock price. The aggregate purchase price payable to us under the 5,442,040 ESUs that remain outstanding is approximately $272.1 million (a purchase price of $50 is payable in respect of the purchase contract under each ESU). For a further description of the ESUs, the purchase contracts constituting a portion thereof and our common stock, see the information set forth under the captions Description of the Equity Security Units and Description of El Paso Capital Stock elsewhere in this prospectus. We intend to use the net proceeds from the issuance of our shares of common stock upon maturity of the purchase contracts for general corporate purposes. See Use of Proceeds.

This prospectus is part of a post-effective amendment to a registration statement filed with the SEC that has been declared effective. This prospectus has been filed with the SEC because under applicable SEC rules we no longer qualify for use of a registration statement on Form S-3 or for incorporation by reference into a prospectus. For a further explanation, see Explanatory Note on page (i) above.

We may be required to amend or supplement this prospectus at any time prior to August 16, 2005 to add, update or change the information contained in this prospectus. This prospectus does not contain all the information you can find in the registration statement or the exhibits filed with the registration statement. You should read this prospectus and any amendment or supplement hereto, together with the registration statement, the exhibits filed with or incorporated by reference into the registration statement and the additional information described under Where You Can Find More

Information.

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RECENT DEVELOPMENTS

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.

Medicine Bow Acquisition

On July 19, 2005, we announced that our wholly owned subsidiary, El Paso Production Holding Company (EPPH), has entered into a definitive agreement to acquire Denver-based Medicine Bow Energy Corporation for $814 million in cash. Medicine Bow is a privately held company with an estimated 356 billion cubic feet equivalent (Bcfe) of proved reserves, mostly in the Rockies and East Texas, which are areas where EPPH conducts operations. Medicine Bow owns directly an estimated 130 Bcfe of proved reserves and 27 million cubic feet per day equivalent (MMcfe) of production. Medicine Bow also owns a 38.6 percent interest in Four Star Oil & Gas Company, through which Medicine Bow owns approximately 226 Bcfe of proved reserves and approximately 68 MMcfe production, net to its interest. The Four Star reserves and volumes will not be consolidated into our or EPPH s financial reports but will be reported as an equity interest. The transaction will be effective July 1, 2005 and is expected to close in the third quarter of 2005.

EPPH will finance the acquisition with 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.

Departure of Principal Officer

On July 18, 2005, we announced that D. Dwight Scott, our executive vice president and chief financial officer resigned to join GSO Capital Partners LP, and will be replaced by D. Mark Leland who currently is executive vice president and chief financial officer of our Production and Non-Regulated operations, effective as of August 10, 2005.

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RISK FACTORS

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

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

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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;

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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;

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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 64 and 93, Notes to Condensed Consolidated Financial Statements, Note 8, on page F-16, and Notes to Consolidated Financial Statements, Note 10, on page F-71.

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;

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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 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.

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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 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 118, Notes to Condensed Consolidated Financial Statements, Note 10, on page F-19, and Notes to Consolidated Financial Statements, Note 17, on page F-87.

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-87.

Our system of internal controls ensure 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, 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-116 through F-118 of this registration statement, we identified several deficiencies in internal control over financial reporting that management has concluded constitute material weaknesses. Although we have taken steps to remediate some of these deficiencies, additional steps must be

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taken to remediate the remaining control deficiencies. In addition, we reported restatements of our financial statements on April 8, 2005 and June 16, 2005 as a result of these material weaknesses. We have made various changes in our internal controls which we believe remediate the material weaknesses previously identified by the company. We are relying on those changes in internal controls as an integral part of our disclosure controls and procedures. If 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 suffer a loss of public confidence in the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, 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 to the risk of not completing the remediation of all deficiencies in our internal controls over financial reporting, 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. In addition, the applicable regulations and literature are relatively new. As a result, they are potentially subject to change in the future, which could include changes in the interpretation of the existing regulations and literature as well as the issuance of more detailed rules and procedures.

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-79, 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 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-

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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.

Risks Related to Our Common Stock

You will bear the entire risk of a decline in the price of our common stock.

The market value of the shares of our common stock you will receive on the stock purchase date may be materially different from the effective price per share paid by you on the settlement date under the applicable purchase contracts. If the average trading price of our common stock on the settlement date under the

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applicable purchase contracts is less than $19.95 per share, you will, on the settlement date, be required to purchase shares of common stock at a loss. Accordingly, a holder of ESUs assumes the entire risk that the market value of our common stock may decline. Any such decline could be substantial.

You will receive only a portion of any appreciation in our common stock price.

The aggregate market value of the shares of our common stock you will receive on the settlement date under the applicable purchase contracts generally will exceed the stated amount of $50 only if the average closing price per share of our common stock over the applicable 20-trading day period preceding settlement equals or exceeds $23.94, which we refer to as the threshold appreciation price. Therefore, during the period prior to the settlement date, an investment in the ESUs affords less opportunity for equity appreciation than a direct investment in our common stock. If the average closing price of our common stock exceeds $19.95, which we refer to as the reference price, but falls below the threshold appreciation price, you will realize no equity appreciation on the common stock for the period during which you own the purchase contract.

The trading price of our common stock and the general level of interest rates and our creditworthiness will directly affect the trading price for the ESUs.

It is impossible to predict whether the price of our common stock or interest rates will rise or fall. Our creditworthiness, operating results and prospects and economic, financial and other factors will affect the trading prices of our common stock. In addition, market conditions can affect the capital markets generally, in turn affecting the price of our common stock. These conditions may include the level of, and fluctuations in, the trading prices of stocks generally and sales of substantial amounts of our common stock in the market after the offering of the ESUs or the perception that those sales could occur. Fluctuations in interest rates may affect the relative value of our common stock subject to issuance upon settlement of the purchase contracts.

You may suffer dilution of our common stock issuable upon settlement of your purchase contract.

The number of shares of our common stock issuable upon settlement of your purchase contract is subject to adjustment only for stock splits and combinations, stock dividends and other specified transactions described in this prospectus. See Description of the Equity Security Units Anti-dilution Adjustments for more information. The number of shares of our common stock issuable upon settlement of each purchase contract is not subject to adjustment for other events, such as employee stock option grants, offerings of common stock for cash, or in connection with acquisitions or other transactions, any of which may adversely affect the price of our common stock. The terms of the ESUs do not restrict our ability to offer common stock in the future or to engage in other transactions that could dilute our common stock. Moreover, we have no obligation to consider the interests of the holders of the ESUs in engaging in any such offering or transaction.

The price of our common stock may fluctuate significantly, which may make it difficult for you to resell the common stock issuable upon settlement of the purchase contracts, 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 common stock is issuable upon settlement of the purchase contracts, volatility or depressed prices for our common stock could have similar effect on the trading price of the ESUs. Holders of ESUs who receive common stock upon settlement of the purchase contracts will also be subject to the risk of volatility and depressed prices.

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

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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 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.

USE OF PROCEEDS

We will receive an aggregate of approximately $272.1 million of cash, received upon the maturity of the pledged treasury securities, (as further discussed under the caption Description of Equity Security Units Settlement on page 143 of this prospectus) upon settlement of the purchase contracts. The net proceeds will be used for general corporate purposes.

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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 17 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	2004
					(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[5]	$ (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[6]	$ 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[7]	$ 31,383	$ 36,943	$ 41,923	$ 44,271	$ 43,992	$ 29,676	$ 31,383

Long-term financing obligations[8]	18,241	20,275	16,106	12,840	11,206	16,379	18,241
Securities of subsidiaries [8]	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-44, for a further discussion of the restatements.

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(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-44 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) 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-56 to F-66.

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

(7) 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-60.

(8) 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 4. 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 Consolidated Financial Statements, Note 1, on page F-44.

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

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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-79. For a further discussion of risks that can impact our liquidity, see Risk Factors beginning on page 4.

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.

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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-79.

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 in 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. So far, in 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 11.

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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)

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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-124, 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 93, and Notes to Consolidated Financial Statements, Note 3, on page F-60, 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-79, 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-79.

(2) See Notes to Consolidated Financial Statements, Note 17, on page F-87.

(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-87.

(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-60 and F-66, 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-60 and F-66, 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

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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-44, 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-60 through F-66, and Note 21, on page F-103.

	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

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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-44, 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

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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

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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 Eastleg and Northleg 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

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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-124, 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 61, Business Non-regulated Business Production Segment, page 104, Risk Factors, page 4, and Supplemental Financial Information, under the heading Supplemental Natural Gas and Oil Operations (Unaudited), on page F-124.

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 24.

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

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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.

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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-87. 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

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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-87.

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-87.

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-87.

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

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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-108 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.

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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-56 to F-60, and Note 22, on page F-108, 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-71.

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

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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-108.

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-87.

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

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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-64, 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-79 through F-86.

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-44.

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-68.

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-108 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

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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-68, 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-68. 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-44.

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.

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Commitments and Contingencies

For a discussion of our commitments and contingencies, see Notes to Consolidated Financial Statements, Note 17, on page F-87, 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

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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-44 and F-71.

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 17 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.

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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.

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-79, 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 4.

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 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 revenue and 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

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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.

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 96 through 105.

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 rates 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

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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 a 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 87.

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.

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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 84. 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.

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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 84.

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, 2005	Quarter Ended June 30, 2004	Quarter Ended June 30, Percent Variance	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	Six Months Ended June 30, 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 27.

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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 gross 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 113 through 114.

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

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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.

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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

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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.

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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 the 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 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 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 plant 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.

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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 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 117.

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.

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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 Item 1, Financial Statements, Note 6.

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

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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 in our 2004 Annual Report on Form 10-K, as amended, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2004 Annual Report on Form 10-K, as amended, 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-103.

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]		
Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	2004	2003 (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 (MMcf/d)	Description	Anticipated Completion Date
ANR	EastLeg 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
	NorthLeg 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 (Percent)	Miles of Pipeline[2]	Design Capacity[2] (MMcf/d)	2004	2003 (BBtu/d)	2002
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		50	71	1,000	951	130	

	Pipeline running from Pemex Compression Station 19 to 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

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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) (768 BBtu/d)	Contract terms expire in 2006. Contract terms expire in 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	Approximately 47 firm contracts	WIC competes with eight interstate pipelines and one intrastate pipeline

customers	Weighted average remaining contract term of approximately six years.	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 Major 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.
	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 (MMcf)	Oil/ Condensate (MBbls)	NGL (MBbls)	Total (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-124.

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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

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

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

Our United States net developed acreage is concentrated primarily in the Gulf of Mexico (47 percent), Utah (14 percent), Texas (9 percent), Oklahoma (8 percent), New Mexico (7 percent) and Louisiana (7 percent). Our United States net undeveloped acreage is concentrated primarily in New Mexico (23 percent), the Gulf of Mexico (22 percent), Louisiana (12 percent), Indiana (8 percent) and Texas (8 percent). Approximately 22 percent, 9 percent and 11 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2005, 2006 and 2007.

The following table details our working interests in natural gas and oil wells at December 31, 2004:

	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
United States								
Onshore	2,864	2,088	292	220	3,156	2,308	59	48
Texas Gulf Coast	808	669	2	1	810	670	5	4
Offshore and south Louisiana	287	194	75	41	362	235	4	1
Total United States	3,959	2,951	369	262	4,328	3,213	68	53
Brazil	4	3	11	9	15	12		

Worldwide Total	3,963	2,954	380	271	4,343	3,225	68	53

(1) Gross interest reflects the total number of wells we participated in, regardless of our ownership interests in the wells.

(2) Net interest is the aggregate of the fractional working interest that we have in our gross wells. At December 31, 2004, we operated 2,952 of the 3,225 net productive wells.

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The following table details our exploratory and development wells drilled during the years 2002 through 2004:

	Net Exploratory Wells Drilled[1]			Net Development Wells Drilled[1]		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
United States						
Productive	13	54	27	298	272	511
Dry	10	22	14	3	1	5
Total	23	76	41	301	273	516
Brazil						
Productive		2				
Dry	1	4				
Total	1	6				
Worldwide						
Productive	13	56	27	298	272	511
Dry	11	26	14	3	1	5
Total	24	82	41	301	273	516

[1] Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.

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The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Sales Prices, Transportation and Production Costs

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

	2004	2003	2002
Net Production Volumes			
United States			
Natural Gas (MMcf)	238,009	338,762	470,082
Oil, Condensate and NGL (MBbls)	8,498	11,778	16,462
Total (MMcfe)	288,994	409,432	568,852
Brazil			
Natural Gas (MMcf)	6,848		
Oil, Condensate and NGL (MBbls)	320		
Total (MMcfe)	8,772		
Worldwide			
Natural Gas (MMcf)	244,857	338,762	470,082
Oil, Condensate and NGL (MBbls)	8,818	11,778	16,462
Total (MMcfe)	297,766	409,432	568,852
Natural Gas Average Realized Sales Price ($/Mcf)[1]			
United States			
Price, excluding hedges	$ 6.02	$ 5.51	$ 3.17
Price, including hedges	$ 5.94	$ 5.40	$ 3.35
Brazil			
Price, excluding hedges	$ 2.01	$	$
Price, including hedges	$ 2.01	$	$
Worldwide			
Price, excluding hedges	$ 5.90	$ 5.51	$ 3.17
Price, including hedges	$ 5.83	$ 5.40	$ 3.35

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	2004	2003	2002
Oil, Condensate, and NGL Average Realized Sales Price ($/Bbl)[1]			
United States			
Price, excluding hedges	$ 34.44	$ 26.64	$ 21.38
Price, including hedges	$ 34.44	$ 25.96	$ 21.28
Brazil			
Price, excluding hedges	$ 43.01	$	$
Price, including hedges	$ 39.19	$	$
Worldwide			
Price, excluding hedges	$ 34.75	$ 26.64	$ 21.38
Price, including hedges	$ 34.61	$ 25.96	$ 21.28
Average Transportation Cost			
United States			
Natural gas ($/Mcf)	$ 0.17	$ 0.18	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 1.16	$ 1.05	$ 0.97
Worldwide			
Natural gas ($/Mcf)	$ 0.17	$ 0.18	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 1.12	$ 1.05	$ 0.97
Average Production Cost($/Mcfe)[2]			
United States			
Average lease operating cost	$ 0.62	$ 0.42	$ 0.42
Average production taxes	0.11	0.14	0.08
Total production cost	$ 0.73	$ 0.56	$ 0.50
Worldwide			
Average lease operating cost	$ 0.60	$ 0.42	$ 0.42
Average production taxes	0.11	0.14	0.08
Total production cost	$ 0.71	$ 0.56	$ 0.50

(1) Prices are stated before transportation costs.

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

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Acquisition, Development and Exploration Expenditures

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

	2004	2003	2002
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 33	$ 10	$ 362
Unproved	32	35	29
Development Costs	395	668	1,242
Exploration Costs:			
Delay Rentals	7	6	7
Seismic Acquisition and Reprocessing	29	56	35
Drilling	149	405	482
Asset Retirement Obligations[1]	30	124	
Total full cost pool expenditures	675	1,304	2,157
Non-full cost pool expenditures	11	17	47
Total capital expenditures	$ 686	$ 1,321	$ 2,204
Brazil			
Acquisition Costs:			
Proved	$ 69	$	$
Unproved	3	4	9
Development Costs	1		
Exploration Costs:			
Seismic Acquisition and Reprocessing	15	11	32
Drilling	10	84	13
Asset Retirement Obligations	3		
Total full cost pool expenditures	101	99	54
Non-full cost pool expenditures	3	1	2
Total capital expenditures	$ 104	$ 100	$ 56

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	2004	2003	2002
		(In millions)	
Worldwide			
Acquisition Costs:			
Proved	$ 102	$ 10	$ 362
Unproved	35	39	38
Development Costs	396	668	1,242
Exploration Costs:			
Delay Rentals	7	6	7
Seismic Acquisition and Reprocessing	44	67	67
Drilling	159	489	495
Asset Retirement Obligations	33	124	
Total full cost pool expenditures	776	1,403	2,211
Non-full cost pool expenditures	14	18	49
Total capital expenditures	$ 790	$ 1,421	$ 2,260

(1) Includes an increase to our property, plant and equipment of approximately $114 million in 2003 associated with our adoption of Statement of Financial Accounting Standards No. 143.

We spent approximately $156 million in 2004, $220 million in 2003 and $275 million in 2002 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

Regulatory and Operating Environment

Our natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world in which we do business. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Our international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international laws and regulations relating to the protection of the environment affect our natural gas and oil operations through their effect on the construction and operation of facilities, water disposal rights, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in material compliance with the applicable requirements. In addition, we maintain insurance to limit exposure to sudden and accidental spills and oil pollution liability.

Our production business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to property or injuries to people. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage to limit exposure to potential losses resulting from these operating hazards.

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Markets and Competition

We primarily sell our domestic natural gas and oil to third parties through our Marketing and Trading segment at spot market prices, subject to customary adjustments. As part of our long-term business strategy, we will continue to sell our natural gas and oil production to this segment. We sell our Brazilian natural gas and oil to Petrobras, a Brazilian energy company. We sell our natural gas liquids at market prices under monthly or long-term contracts, subject to customary adjustments. We also engage in hedging activities on a portion of our natural gas and oil production to stabilize our cash flows and reduce the risk of downward commodity price movements on sales of our production.

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms and our ability to access drilling and other equipment on a timely and cost effective basis. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Non-regulated Business Marketing and Trading Segment

Our Marketing and Trading segment s operations primarily involve the marketing of our natural gas and oil production and the management of our remaining trading portfolio. Our operations in this segment over the past several years have been impacted by a number of significant events both in this business and in the industry. As a result of the deterioration of the energy trading environment in late 2001 and 2002 and the reduced availability of credit to us, we announced in November 2002 that we would reduce our involvement in the energy trading business and pursue an orderly liquidation of our historical trading portfolio. In December 2003, we announced that our historical energy trading operations would become a marketing and trading business focused on the marketing and physical trading of the natural gas and oil from our Production segment. Our Marketing and Trading segment s portfolio is grouped into several categories. Each of these categories includes contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. The types of contracts used in this segment are as follows:

Natural gas derivative contracts. Our natural gas contracts include long-term obligations to deliver natural gas at fixed prices as well as derivatives related to our production activities. As of December 31, 2004, we have seven significant physical natural gas contracts with power plants. These contracts have various expiration dates ranging from 2011 to 2028, with expected obligations under individual contracts with third parties ranging from 32,000 MMBtu/d to 142,000 MMBtu/d.

Additionally, as of December 31, 2004, we had executed contracts with third parties, primarily fixed for floating swaps, that effectively hedged approximately 244 TBtu of our Production segment s anticipated natural gas production through 2012. In addition to these hedge contracts, as of December 31, 2004, we are a party to other derivative contracts designed to provide price protection to El Paso from declines in natural gas prices in 2005 and 2006. Specifically, these contracts provide El Paso 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 March 2005, we entered into additional contracts that provide El Paso a floor price of $6.00 per MMBtu on 30 TBtu of natural gas production in 2007 and a ceiling price of $9.50 per MMBtu on 60 TBtu of natural gas production in 2006.

Transportation-related contracts. Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. We typically refer to the fixed reservation cost as a demand charge. As of December 31, 2004, we have contracted for 1.5 Bcf/d of capacity with contract expiration dates through 2028. Our ability to utilize our transportation capacity is dependent on several factors including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of capital needed to use this capacity and the capacity required to meet our other long-term obligations.

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Tolling contracts. Our tolling contracts provide us with the right to require counterparties to convert natural gas into electricity. Under these arrangements, we supply the natural gas used in the underlying power plants and sell the electricity produced by the power plant. In exchange for this right, we pay a monthly fixed fee and a variable fee based on the quantity of electricity produced. As of December 31, 2004, we have two unaffiliated physical tolling contracts, the largest of which is a contract on the Cordova power project in the Midwest. This contract expires in 2019.

Power and other. Our power and other contracts include long-term obligations to provide power to our Power segment for its restructured domestic power contracts. As of December 31, 2004, we have four power supply contracts remaining, the largest being a contract with Morgan Stanley for approximately 1,700 MMWh per year extending through 2016. In the first quarter of 2005, we sold two of these contracts related to subsidiaries in our Power segment, Cedar Brakes I and II. We also have other contracts that require the physical delivery of power or that are used to manage the risk associated with our obligations to supply power. In addition, we have natural gas storage contracts that provide capacity of approximately 4.7 Bcf of storage for operational and balancing purposes.

Markets and Competition

Our Marketing and Trading segment operates in a highly competitive environment, competing on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served is influenced directly or indirectly by energy market economics. Our primary competitors include:

Affiliates of major oil and natural gas producers;

Large domestic and foreign utility companies;

Affiliates of large local distribution companies;

Affiliates of other interstate and intrastate pipelines; and

Independent energy marketers and power producers with varying scopes of operations and financial resources.

Non-regulated Business Power Segment

Our Power segment includes the ownership and operation of international and domestic power generation facilities as well as the management of restructured power contracts. As of December 31, 2004, we owned or had interests in 37 power facilities in 16 countries with a total generating capacity of approximately 10,400 gross MW. Our commercial focus has historically been either to develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing above-market power purchase agreements. However, during 2004, we completed the sale of substantially all of our domestic power generation facilities and a significant portion of our domestic power restructuring business. We will continue to evaluate potential opportunities to sell or otherwise divest the remaining domestic assets and a number of international assets, such that our long-term focus will be on maximizing the value of our power assets in Brazil.

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International Power. As of December 31, 2004, we owned or had a direct investment in the following international power plants (only significant assets and investments are listed):

Project	Country	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Brazil						
Araucaria[1]	Brazil	60	484	Copel	[2]	Natural Gas
Macae	Brazil	100	928	Petrobras[3]	2007[2]	Natural Gas
Manaus	Brazil	100	238	Manaus Energia[4]	2008	Oil
Porto Velho[1]	Brazil	50	404	Eletronorte	2010,2023	Oil
Rio Negro	Brazil	100	158	Manaus Energia[4]	2008	Oil
Asia						
Fauji[1]	Pakistan	42	157	Pakistan Water and Power	2029	Natural Gas
Habibullah[1]	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
KIECO[1]	South Korea	50	1,720	KEPCO	2020	Natural Gas
Meizhou Wan[1]	China	26	734	Fujian Power	2025	Coal
Haripur[1]	Bangladesh	50	116	Bangladesh Power	2014	Natural Gas
PPN[1][5]	India	26	325	Tamil Nadu	2031	Naphtha/Natural Gas
Saba[1]	Pakistan	94	128	Pakistan Water and Power	2029	Oil
Sengkang[1]	Indonesia	48	135	PLN	2022	Natural Gas
Central and other South America						
Aguaytia[1]	Peru	24	155	Various	2005,2006	Natural Gas
Fortuna[1]	Panama	25	300	Union Fenosa	2005,2008	Hydroelectric
Itabo[1]	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Nejapa	El Salvador	87	144	AES and PPL	2005	Oil
Europe						
Enfield[1]	United Kingdom	25	378	Spot Market		Natural Gas
EMA[1]	Hungary	50	69	Dunaferr Energy Services	2016	Natural Gas/Oil

[1] These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.

[2] These facilities power sales contracts are currently in arbitration.

(3) Although a majority of the power generated by this power facility is sold to the wholesale power markets, Petrobras provides a minimum level of revenue under its contract until 2007. Petrobras did not make their December 2004 and January 2005 payments under this contract and have filed a lawsuit and for arbitration. See Notes to Consolidated Financial Statements, Note 17, on page F-87, for a further discussion of this matter.

(4) These power facilities have new power purchase agreements that were signed in January 2005 extending the terms of the contract through 2008 at which time we will transfer ownership of the plants to Manaus Energia.

(5) We sold our investment in this plant in the first quarter of 2005.

In addition to the international power plants above, our Power segment also has investments in the following international pipelines:

Pipeline	El Paso Ownership Interest	Miles of Pipeline	Design Capacity[1]	Average 2004 Throughput[1]
	(Percent)		(MMcf/d)	(BBtu/d)
Bolivia to Brazil	8	1,957	1,059	722
Argentina to Chile	22	336	124	77

(1) Volumes represent the pipeline s total design capacity and average throughput and are not adjusted for our ownership interest.

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Domestic Power Plants. During 2004, we sold substantially all of our domestic power assets. As of December 31, 2004, we owned or had a direct investment in the following domestic power facilities (only significant assets and investments are listed):

Project	State	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Berkshire[1]	MA	56	261	[2]	[2]	Natural Gas
Midland Cogeneration[1]	MI	44	1,575	Consumers Power, Dow	2025	Natural Gas
CDECCA[3]	CT	100	62	[2]	[2]	Natural Gas
Pawtucket[3]	RI	100	69	[2]	[2]	Natural Gas
San Joaquin[3]	CA	100	48	[2]	[2]	Natural Gas
Eagle Point[4]	NJ	100	233	[2]	[2]	Natural Gas
Rensselaer[4]	NY	100	86	[2]	[2]	Natural Gas

[1] These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.

[2] These power facilities (referred to as merchant plants) do not have long-term power purchase agreements with third parties. Our Marketing and Trading segment sells the power that a majority of these facilities generate to the wholesale power market.

[3] These plants have Board approval for sale and are targeted to be sold in the first half of 2005. We have executed sales agreements on the Pawtucket and San Joaquin facilities.

[4] These plants were sold in the first quarter of 2005.

Domestic Power Contract Restructuring. In addition to our domestic power plants, we were historically involved in a power restructuring business. This business involved restructuring above-market, long-term power purchase agreements with utilities that were originally tied to older power plants built under the Public Utility Regulatory Policies Act of 1978 (PURPA). These PURPA facilities were typically less efficient and more costly to operate than newer power generation facilities.

While we are no longer actively restructuring additional power purchase contracts, we continue to manage the purchase and sale of electricity required under the contracts related to Cedar Brakes I and II and continue to perform under the Mohawk River Funding II contracts. We also retained an interest in Mohawk River Funding III, which is an entity that currently has a claim against an entity in bankruptcy related to a previously restructured power contract. During 2004, we completed the sale of Utility Contract Funding (UCF) and signed binding agreements to sell Cedar Brakes I and II. We completed the sale of Cedar Brakes I and II in the first quarter of 2005.

Regulatory Environment & Markets and Competition

International. Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of these countries have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures are subject to change (including differing interpretations) over time.

Many of our international power generation facilities sell power under long-term power purchase agreements primarily with power transmission and distribution companies owned by the local governments where the facilities are located. When these long-term contracts expire, these facilities will be subject to regional market, competitive and political risks.

Domestic. Our domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to the rates, terms and conditions of service of these regulated plants. Our cogeneration power production activities are regulated by the FERC under PURPA with respect to rates, procurement and provision of services and operating standards. Our power generation activities are also subject to federal, state and local environmental regulations.

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Non-regulated Business Field Services Segment

Our Field Services segment conducts our midstream activities, which include gathering and processing of natural gas for natural gas producers, primarily in the south Louisiana production area, and held our ownership interests in Enterprise Products Partners, a publicly traded master limited partnership.

Gathering and Processing Assets. As of December 31, 2004, our gathering systems consisted of 240 miles of pipeline with 665 MMcfe/d of throughput capacity. These systems had average throughput of 203 BBtue/d during 2004. Our processing facilities had operational capacity and volumes as follows:

Processing Plants	Inlet Capacity December 31, 2004	Average Inlet Volume 2004	Average Inlet Volume 2003	Average Inlet Volume 2002	Average Sales 2004	Average Sales 2003	Average Sales 2002
	(MMcfe/d)	(BBtue/d)			(Mgal/d)		
South Louisiana	2,550	1,600	1,627	1,407	1,631	1,726	1,604
Other areas[1]	186	1,180	1,579	2,513	2,460	2,611	5,134
Total	2,736	2,780	3,206	3,920	4,091	4,337	6,738

[1] During 2002, 2003 and 2004, we sold a substantial amount of our midstream assets to GulfTerra and Enterprise. Included in the volume and sales columns is activity through the sale date for the assets which were sold.

In January 2005, we sold to Enterprise the membership interests in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs gathering and processing facilities.

General and Limited Partner Interests in Enterprise Products Partners, L.P. During 2003, and through September 2004, we held significant interests in GulfTerra Energy Partners, L.P. In September 2004, GulfTerra merged with Enterprise Products Partners, and we sold our ownership interests in GulfTerra along with our interests in processing assets in South Texas in exchange for cash, a 9.9 percent general partner interest in Enterprise, and 13.5 million units in Enterprise. In January 2005, we sold all of our interests in Enterprise and its general partner for cash.

Regulatory Environment. Some of our operations, owned directly or through equity investments, are subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of our operations, owned directly or through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979 and various environmental statutes and regulations. Each of our pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and we believe that these systems are in material compliance with the applicable requirements.

Markets and Competition. We compete with major interstate and intrastate pipeline companies in transporting natural gas and NGL. We also compete with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and NGL. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling and production activity, customer service and access to favorable downstream markets.

Other Operations and Assets

We currently have a number of other assets and businesses that are either included as part of our corporate activities or as discontinued operations.

Corporate Activities

Our corporate operations include our general and administrative functions as well as a telecommunications business, a telecommunications facility in Chicago and various other contracts and assets,

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including those related to our financial services, petroleum ship charter and LNG operations, all of which are insignificant to our results in 2004.

Discontinued Operations

Our discontinued operations consist of our petroleum markets business and international natural gas and oil production operations, primarily in Canada.

Environmental

A description of our environmental activities is included in Notes to Consolidated Financial Statements, Note 17, on page F-87 and is incorporated herein by reference.

Employees

As of May 23, 2005, we had approximately 6,400 full-time employees, of which 427 employees in Brazil are subject to collective bargaining arrangements.

Properties

A description of our properties is included under Business beginning on page 93.

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

Legal Proceedings

Details of the cases listed below, as well as a description of our other legal proceedings are included in Notes to Condensed Consolidated Financial Statements, Note 10, on page F-19, and Notes to Consolidated Financial Statements, Note 17 on page F-87.

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and *Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002. The purported shareholder class actions relating to our reserve restatement filed in the U.S. District Court for the Southern District of Texas, Houston Division, which have now been consolidated with the above referenced purported shareholder class actions, are: *James Felton v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Sinclair Haberman v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Patrick Hinner v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Stanley Peltz v. El Paso Corporation, Ronald*

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Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Yolanda Cifarelli v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Andrew W. Albstein v. El Paso Corporation, William Wise; George S. Johnson v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, and D. Dwight Scott; Robert Corwin v. El Paso Corporation, Mark Leland, Brent Austin; Ronald Kuehn, Jr., D. Dwight Scott and William Wise; Michael Copland v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Leslie Turbowitz v. El Paso Corporation, Mark Leland, Brent Austin, Ronald Kuehn, Jr., D. Dwight Scott and William Wise; David Sadek v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott; Stanley Sved v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Nancy Gougler v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; William Sinnreich v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Joseph Fisher v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; and Glickenhaus & Co. v. El Paso Corporation, Rod Erskine, Ronald Kuehn, Jr., Brent Austin, William Wise, Douglas Foshee and D. Dwight Scott; Haberman v. El Paso Corporation et al and Thompson v. El Paso Corporation et al. The purported shareholder action filed in the Southern District of New York is *IRA F.B.O. Michael Conner et al v. El Paso Corporation, William Wise, H. Brent Austin, Jeffrey Beason, Ralph Eads, D. Dwight Scott, Credit Suisse First Boston, J.P. Morgan Securities,* filed October 25, 2002.

The stayed shareholder derivative actions filed in the United States District Court for the Southern District of Texas, Houston Division are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002, and *Russo v. William Wise, Brent Austin, Dwight Scott, Ralph Eads, Ronald Kuehn, Jr., Douglas Foshee, Rodney Erskine, PricewaterhouseCoopers and El Paso Corporation* filed in September 2004. The consolidated shareholder derivative action filed in Houston is *John Gebhart and Marilyn Clark v. El Paso Natural Gas, El Paso Merchant Energy, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, William Wise, Joe Wyatt, Ralph Eads, Brent Austin and John Somerhalder* filed in November 2002. The stayed shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

Environmental Proceedings

Kentucky PCB Project. In November 1988, the Kentucky Natural Resources and Environmental Protection Cabinet filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into interim agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the Environmental Protection Agency (EPA). Despite TGP s remediation efforts, the agency may raise additional technical issues or seek additional remediation work and/or penalties in the future.

Shoup Natural Gas Processing Plant. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to exceeding the emission limit, testing, reporting, and recordkeeping issues in 2001. On December 29, 2004, TCEQ issued an Executive Director s Preliminary Report and Petition revising the allegations from the past NOE and seeking a penalty of $419,650. Following discussions with TCEQ, we have executed an agreed order to resolve the allegations for $202,400, which includes a $106,459 penalty payment to TCEQ and a $95,961 payment for a supplemental environmental project. We will make these payments once TCEQ has executed the agreed order.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality issued an Executive Director s Preliminary Report and Petition seeking $645,477 in penalties relating to air violations alleged to have occurred at our former Corpus Christi, Texas refinery from 1996 to 2000. We filed a hearing request to protect our procedural rights. Pursuant to discussions on March 16, 2005,

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the parties have reached an agreement in principle to resolve the allegations for $272,097. The parties are drafting the final settlement document formalizing the agreement.

Coastal Eagle Point Air Issues. Pursuant to the EPA s Petroleum Refinery Initiative, our former Eagle Point refinery resolved certain claims of the U.S. and the State of New Jersey in a Consent Decree entered in December 2003. The Eagle Point refinery will invest an estimated $3 million to $7 million to upgrade the plant s environmental controls by 2008. The Eagle Point Refinery was sold in January 2004. We will share certain future costs associated with implementation of the Consent Decree pursuant to the Purchase and Sale Agreement. On April 1, 2004, the New Jersey Department of Environmental Protection issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking $183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003, prior to the sale. We have filed an administrative appeal contesting the penalty.

Natural Buttes. On May 19, 2003, we met with the EPA to discuss potential prevention of significant deterioration violations due to a de-bottlenecking modification at Colorado Interstate Gas Company s facility. The EPA issued an Administrative Compliance Order. We are in negotiations with the EPA as to the appropriate penalty and have reserved our anticipated settlement amount.

Air Permit Violation. In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. Pursuant to discussions with LDEQ, we have reached an agreement in principle to resolve the allegations for $77,287. The parties are drafting the final settlement document formalizing the agreement.

MARKET PRICE OF AND DIVIDENDS ON THE COMMON STOCK AND RELATED STOCKHOLDER MATTERS

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of July 5, 2005, we had 47,907 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

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

	High	Low	Dividends
		(Per share)	
2005			
Second Quarter	$ 11.87	$ 9.30	$ 0.04
First Quarter	13.15	10.01	0.04
2004			
Fourth Quarter	$ 11.85	$ 8.42	$ 0.04
Third Quarter	9.20	7.37	0.04
Second Quarter	7.95	6.58	0.04
First Quarter	9.88	6.57	0.04
2003			
Fourth Quarter	$ 8.29	$ 5.97	$ 0.04
Third Quarter	8.95	6.51	0.04
Second Quarter	9.89	5.85	0.04
First Quarter	10.30	3.33	0.04

Future dividends will be payable only when, as and if declared by our Board of Directors and will be dependent on business conditions, earnings, our cash requirements and other relevant factors.

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Odd-lot Sales Program

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

Equity Compensation Plan Information

The following table provides information concerning equity compensation plans as of December 31, 2004, that have been approved by stockholders and equity compensation plans that have not been approved by stockholders. The table includes (a) the number of securities to be issued upon exercise of options, warrants and rights outstanding under the equity compensation plans, (b) the weighted-average exercise price of all outstanding options, warrants and rights and (c) additional shares available for future grants under all of El Paso s equity compensation plans.

	(a)	(b)	(c)
Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (1)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by stockholders	6,624,686	$ 28.07	4,537,843(2)
Equity compensation plans not approved by stockholders	24,954,615	$ 47.00	25,804,722(3)
Total	31,579,301		30,342,565

(1) Column (a) does not include 2,344,277 shares with a weighted-average exercise price of $38.62 per share which were assumed by El Paso under the Executive Award Plan of Sonat Inc. as a result of the merger with Sonat in October 1999. The Executive Award Plan of Sonat Inc. has been terminated and no future awards can be made under it.

(2)

In column (c), equity compensation plans approved by stockholders include 2,831,050 shares available for future issuance under the Employee Stock Purchase Plan.

(3) In column (c), equity compensation plans not approved by stockholders include 77,568 shares available for future awards granted under the Restricted Stock Award Plan for Management Employees.

The Board s proposal to adopt the El Paso Corporation 2005 Omnibus Incentive Compensation Plan (the 2005 Plan) was approved by our stockholders effective May 26, 2005. The 2005 Plan replaces all existing stockholder approved and non-stockholder approved plans, which are reflected above in the equity compensation plan table and further described below. The Board s proposal to adopt the 2005 Compensation Plan for Non-Employee Directors was also approved by our stockholders effective May 26, 2005. This plan replaces the 1995 Compensation Plan for Non-Employee Directors. We have canceled all remaining shares available for grant under the prior plans and will not make any further grants from these plans.

Stockholder Approved Plans

El Paso 2005 Omnibus Incentive Compensation Plan. This plan provides for the grant to all salaried employees (other than an employee who is a member of a unit covered by a collective bargaining agreement) of El Paso and the members of our Board of Directors who are salaried officers of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, incentive

awards, cash awards and other stock-based awards. In addition, the plan administrator may grant awards to any person who, in the sole discretion of the plan administrator, holds a position of responsibility and is able to contribute substantially to the success of El Paso. The plan administrator also designates which employees are eligible to participate. Subject to any adjustments for a change in capitalization (as defined in the plan), a maximum of 35,000,000 shares in the aggregate may be subject to awards under the plan, provided however, that a maximum of 17,500,000 shares in the aggregate may be issued under the plan with respect to restricted stock, restricted stock units, performance shares, performance units and other stock-based awards. Except as otherwise provided in an award agreement, in the event of a participant s termination of employment without cause or by the participant for good reason (as defined in the plan), if applicable, within two years following a change in control (defined in substantially the same manner as under the 2004 Key Executive Severance Protection Plan) (1) all stock options and stock appreciation rights will become fully vested and exercisable, (2) the restriction periods applicable to all shares of restricted stock and restricted stock units will immediately lapse, (3) the performance periods applicable to any performance shares, performance units and incentive awards that have not ended will end and such awards will become vested and payable in cash in an amount equal to the target level thereof (assuming target levels of performance by both participants and El Paso have been achieved) within ten days following such termination and (4) any restrictions applicable to cash awards and other stock-based awards will immediately lapse and, if applicable, become payable within ten days following such termination. The plan generally may be amended at any time, provided that stockholder approval is required to the extent required by law, regulation or stock exchange, and no change in any award previously granted under the plan may be made without the consent of the participant if such change would impair the right of the participant to acquire or retain common stock or cash that the participant may have acquired as a result of the plan.

2005 Compensation Plan for Non-Employee Directors. This plan provides for the compensation of our non-employee directors. Each non-employee director is eligible to participate in the plan immediately upon his or her election to the Board of Directors. Subject to the terms of the plan, the plan is administered by the Management Committee. Subject to adjustment as provided in the plan (for example, in the event of a recapitalization, stock split, stock dividend, merger, reorganization or similar event), the maximum number of shares of common stock which may be awarded under the plan is 2,500,000. Our Board of Directors establishes, from time to time, the amount of each participant s compensation. For purposes of the plan, the term compensation means the participant s annual retainer and meeting fees, if any, for each regular or special meeting of the Board and any committee meetings attended. Each participant may elect to receive his or her compensation in any combination of cash, deferred cash or deferred shares of common stock. To the extent a participant receives deferred shares of common stock rather than cash, he or she is credited with deferred shares with a value representing a 25 percent premium to the cash retainer he or she would have otherwise received. Each participant is entitled to receive a long-term equity credit under the plan in the form of shares of deferred common stock (excluding any premium) equal to the amount of the annual retainer. Participants do not receive their deferred amounts until they cease to be a director of El Paso. If the Management Committee determines that the maximum number of shares of common stock which may be awarded under the plan has been issued, then phantom stock units which will have an accounting value equal to the fair market value of one share of common stock shall be awarded. If a participant ceases to continue to serve as a director after a change in control (defined in substantially the same manner as under the 2004 Key Executive Severance Protection Plan) of El Paso, all deferred cash and shares of deferred common stock will be paid and/ or distributed, as the case may be, to a participant (or to his or her beneficiary in the case of the participant s death) within 30 days after the date of the change in control. Subject to the Board of Directors, the Management Committee may from time to time amend the plan, provided that stockholder approval is required to the extent required by applicable law, regulation or stock exchange.

2001 Omnibus Incentive Compensation Plan, 1999 Omnibus Incentive Compensation Plan and 1995 Omnibus Compensation Plan Terminated Plans. These plans provided for the grant to eligible officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. These plans have been replaced by the 2005 Omnibus Incentive Compensation Plan. Although these plans have been terminated with respect to new grants, certain stock options and shares of restricted stock remain outstanding under them. If a change in

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control of El Paso occurs, all outstanding stock options become fully exercisable and restrictions placed on restricted stock lapse. For purposes of the plans, the term change in control has substantially the same meaning given such term in the Key Executive Severance Protection Plan.

Non-Stockholder Approved Plans

Strategic Stock Plan, Restricted Stock Award Plan for Management Employees and Omnibus Plan for Management Employees Terminated Plans. These equity compensation plans had not been approved by the stockholders. The Strategic Stock Plan provided for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to non-employee members of the Board of Directors, officers and key employees of El Paso and its subsidiaries primarily in connection with El Paso s strategic acquisitions. The Restricted Stock Award Plan for Management Employees provided for the grant of restricted stock to management employees (other than executive officers and directors) of El Paso and its subsidiaries for specific accomplishments beyond that which were normally expected and which had a significant and measurable impact on the long-term profitability of El Paso. The Omnibus Plan for Management Employees provided for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to salaried employees (other than employees covered by a collective bargaining agreement) of El Paso and its subsidiaries. These plans have been replaced by the 2005 Omnibus Incentive Compensation Plan. Although these plans have been terminated with respect to new grants, certain stock options and shares of restricted stock remain outstanding under them. If a change in control of El Paso occurs, outstanding stock options granted under the Strategic Stock Plan and Omnibus Plan for Management Employees become fully exercisable and restrictions placed on restricted stock lapse. For purposes of the Strategic Stock Plan and Omnibus Plan for Management Employees, the term change of control has substantially the same meaning given such term in the Key Executive Severance Protection Plan.

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DIRECTORS AND EXECUTIVE OFFICERS

Our directors and executive officers as of June 1, 2005, are listed below. Prior to August 1, 1998, all references to El Paso refer to positions held with El Paso Natural Gas Company.

Name	Office	Officer/ Director Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso, Director	2003	45
D. Dwight Scott	Executive Vice President and Chief Financial Officer of El Paso	2002	41
Robert W. Baker	Executive Vice President and General Counsel of El Paso	1996	48
Lisa A. Stewart	Executive Vice President of El Paso and President of El Paso Production and Non-Regulated Operations	2004	47
Ronald L. Kuehn, Jr.	Chairman of the Board	1999	69
Juan Carlos Braniff	Director	1997	47
James L. Dunlap	Director	2003	67
Robert W. Goldman	Director	2003	62
Anthony W. Hall, Jr.	Director	2001	60
Thomas R. Hix	Director	2004	57
William H. Joyce	Director	2004	69
J. Michael Talbert	Director	2003	58
Robert F. Vagt	Director	2005	58
John L. Whitmire	Director	2003	64
Joe B. Wyatt	Director	1999	69

Douglas L. Foshee has been President, Chief Executive Officer, and a Director of El Paso since September 2003. Mr. Foshee became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. In December 2003, several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, filed for bankruptcy protection, whereby the subsidiaries jointly resolved their asbestos claims. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer, and Chairman of the Board at Nuevo Energy Company. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Operating Officer and Chief Executive Officer.

D. Dwight Scott has been Executive Vice President and Chief Financial Officer of El Paso since October 2002. Mr. Scott served as Senior Vice President of Finance and Planning for El Paso from July 2002 to September 2002. Mr. Scott was Executive Vice President of Power for El Paso Merchant Energy from December 2001 to June 2002, and he served as Chief Financial Officer of El Paso Global Networks from October 2000 to November 2001. Prior to that, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

Robert W. Baker has been Executive Vice President and General Counsel of El Paso since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. He was Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time he held various positions in the legal department of Tenneco Energy and El Paso since 1983.

Lisa A. Stewart has been an Executive Vice President of El Paso since November 2004, and President of El Paso Production and Non-Regulated Operations since February 2004. Ms. Stewart was Executive Vice

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President of Business Development and Exploration and Production Services for Apache Corporation from 1995 to February 2004. From 1984 to 1995, Ms. Stewart worked in various positions for Apache Corporation.

Juan Carlos Braniff has served as a director since 1997. He is currently the Chairman of our Audit Committee and a member of our Finance Committee. Mr. Braniff has been a business consultant since January 2004. He served as Vice Chairman of Grupo Financíero BBVA Bancomer from October 1999 to January 2004, as Deputy Chief Executive Officer of Retail Banking from September 1994 to October 1999 and as Executive Vice President of Capital Investments and Mortgage Banking from December 1991 to September 1994.

James L. Dunlap has served as a director since 2003. He is currently a member of our Compensation Committee and of our Governance & Nominating Committee. Mr. Dunlap s primary occupation has been as a business consultant since 1999. He served as Vice Chairman, President and Chief Operating Officer of Ocean Energy/ United Meridian Corporation from 1996 to 1999. He was responsible for exploration and production and the development of the international exploration business. For 33 years prior to that date, Mr. Dunlap served Texaco, Inc. in various positions, including Senior Vice President, President of Texaco USA, President and Chief Executive Officer of Texaco Canada Inc. and Vice Chairman of Texaco Ltd., London. Mr. Dunlap is currently a member of the board of directors of Massachusetts Mutual Life Insurance Company, a trustee of the Nantucket Conservation Foundation, a trustee of the Culver Educational Foundation and a member of the Corporation of the Woods Hole Oceanographic Institution.

Robert W. Goldman has served as a director since 2003. He is currently the Chairman of our Finance Committee and a member of our Audit Committee. Mr. Goldman s primary occupation has been as a business consultant since October 2002. He served as Senior Vice President, Finance and Chief Financial Officer of Conoco Inc. from 1998 to 2002 and Vice President, Finance from 1991 to 1998. For more than five years prior to that date, he held various executive positions with Conoco Inc. and E.I. Du Pont de Nemours & Co., Inc. Mr. Goldman was also formerly Vice President and Controller of Conoco Inc. and Chairman of the Accounting Committee of the American Petroleum Institute. He is currently Vice President, Finance of the World Petroleum Council, and a member of the board of directors of Tesoro Corporation and the Executive Committee of the board of The Alley Theatre.

Anthony W. Hall, Jr. has served as a director since 2001. He is currently the Chairman of our Governance & Nominating Committee and a member of our Health, Safety & Environmental Committee. Mr. Hall has been Chief Administrative Officer of the City of Houston since January 2004. He served as the City Attorney for the City of Houston from March 1998 to January 2004. He served as a director of The Coastal Corporation from August 1999 to January 2001. Prior to March 1998, Mr. Hall was a partner in the Houston law firm of Jackson Walker, LLP. He is a director of Houston Endowment Inc. and Chairman of the Boulé Foundation.

Thomas R. Hix has served as a director since 2004. He is currently a member of our Audit Committee and of our Finance Committee. Mr. Hix has been a business consultant since January 2003. He served as Senior Vice President of Finance and Chief Financial Officer of Cooper Cameron Corporation from January 1995 to January 2003. From September 1993 to April 1995, Mr. Hix served as Senior Vice President of Finance, Treasurer and Chief Financial Officer of The Western Company of North America. Mr. Hix is a member of the board of directors of The Offshore Drilling Company and Health Care Service Corporation.

William H. Joyce has served as a director since 2004. He is currently a member of our Governance & Nominating Committee and of our Health, Safety & Environmental Committee. Dr. Joyce has been Chairman of the Board and Chief Executive Officer of Nalco Company since November 2003. From May 2001 to October 2003, he served as Chief Executive Officer of Hercules Inc. In 2001, Dr. Joyce served as Vice Chairman of the Board of Dow Chemical Corporation following its merger with Union Carbide Corporation. Dr. Joyce was named Chief Executive Officer of Union Carbide Corporation in 1995 and Chairman of the Board in 1996. Prior to 1995, Dr. Joyce served in various positions with Union Carbide. Dr. Joyce is a director of CVS Corporation and Celanese Corporation.

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Ronald L. Kuehn, Jr. is currently the Chairman of our Board of Directors. Mr. Kuehn was Chairman of the Board and Chief Executive Officer from March 2003 to September 2003. From September 2002 to March 2003, Mr. Kuehn was the Lead Director of El Paso. From January 2001 to March 2003, he was a business consultant. Mr. Kuehn served as non-executive Chairman of the Board of El Paso from October 25, 1999 to December 31, 2000. Mr. Kuehn served as President and Chief Executive Officer of Sonat Inc. from June 1984 until his retirement on October 25, 1999. He was Chairman of the Board of Sonat Inc. from April 1986 until his retirement. He is a director of AmSouth Bancorporation, Praxair, Inc. and The Dun & Bradstreet Corporation.

J. Michael Talbert has served as a director since 2003. He is currently a member of our Compensation Committee and of our Health, Safety & Environmental Committee. Mr. Talbert has been Chairman of the Board of Transocean Inc. since October 2002. He served as Chief Executive Officer of Transocean Inc. and its predecessor companies from 1994 until October 2002, and has been a member of its board of directors since 1994. He served as President and Chief Executive Officer of Lone Star Gas Company from 1990 to 1994. He served as President of Texas Oil & Gas Company from 1987 to 1990, and served in various positions at Shell Oil Company from 1970 to 1982. Mr. Talbert is a director of The Offshore Drilling Company. Mr. Talbert is a past Chairman of the National Ocean Industries Association and a member of the University of Akron s College of Engineering Advancement Council.

Robert F. Vagt has served as a director since May 2005. Mr. Vagt has been President of Davidson College since 1997. He served as President and Chief Operating Officer of Seagull Energy Corporation from 1996 to 1997. From 1992 to 1996, Mr. Vagt served as President, Chairman and Chief Executive Officer of Global Natural Resources. He served as President and Chief Operating Officer of Adobe Resources Corporation from 1989 to 1992. Prior to 1989, Mr. Vagt served in various positions with Adobe Resources Corporation and its predecessor entities. He is a member of the board of directors of Cornell Companies, Inc.

John L. Whitmire has served as a director since 2003. He currently serves as Chairman of our Health, Safety & Environmental Committee and as a member of our Audit Committee. Mr. Whitmire has been Chairman of CONSOL Energy, Inc. since 1999. He served as Chairman and Chief Executive Officer of Union Texas Petroleum Holdings, Inc. from 1996 to 1998, and spent over 30 years serving Phillips Petroleum Company in various positions including Executive Vice President of Worldwide Exploration and Production from 1992 to 1996 and Vice President of North American Exploration and Production from 1988 to 1992. He also served as a member of the Phillips Petroleum Company Board of Directors from 1994 to 1996. He is a member of the board of directors of GlobalSantaFe Inc.

Joe B. Wyatt has served as a director since 1999. He is currently the Chairman of our Compensation Committee and a member of our Governance & Nominating Committee. Mr. Wyatt has been Chancellor Emeritus of Vanderbilt University since August 2000. For eighteen years prior to that date, he served as Chancellor, Chief Executive Officer and Trustee of Vanderbilt University. Prior to joining Vanderbilt University, Mr. Wyatt was a member of the faculty and Vice President of Harvard University. From 1984 until October 1999, Mr. Wyatt was a director of Sonat Inc. He is a director of Ingram Micro, Inc. and Hercules, Inc. He is a principal of the Washington Advisory Group and Chairman of the Universities Research Association.

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EXECUTIVE COMPENSATION

This table and narrative text discusses the compensation paid in 2004, 2003 and 2002 to our Chief Executive Officer and our four other most highly compensated executive officers. The compensation reflected for each individual was for their services provided in all capacities to El Paso and its subsidiaries. This table also identifies the principal capacity in which each of the executives named in this prospectus served El Paso at the end of 2004.

Summary Compensation Table

					Long-Term Compensation			
		Annual Compensation			Awards		Payouts	
Name and Principal Position	Year	Salary ($)[1]	Bonus ($)	Other Annual Compensation ($)[2]	Restricted Stock Awards ($)[3]	Securities Underlying Options (#)	Long-Term Incentive Plan Payouts ($)[4]	All Other Compensation ($)[5]
Douglas L. Foshee[6] President and Chief Executive Officer	2004	$ 630,000	$ 1,250,000		$ 1,320,000	375,000	$ 180,500	$ 51,750
	2003	$ 297,115	$ 600,000		$	1,000,000	$	$ 1,758,913
John W. Somerhalder II[7] Executive Vice President	2004	$ 642,000	$ 684,735		$ 492,800	140,000	$	$ 46,500
	2003	$ 617,500	$ 750,000		$		$ 215,850	$ 14,250
	2002	$ 600,000	$		$		$	$ 81,926
Lisa A. Stewart[8] Executive Vice President	2004	$ 458,337	$ 441,604		$ 1,077,600	295,000	$	$ 316,250
D. Dwight Scott Executive Vice President and Chief Financial Officer	2004	$ 453,929	$ 498,644		$ 739,200	210,000	$ 261,300	$ 42,825
	2003	$ 517,504	$ 750,000		$		$	$ 511,775
	2002	$ 387,504	$		$		$	$ 71,108
Robert W. Baker Executive Vice President	2004	$ 404,004	$ 295,203		$ 492,800	140,000	$ 97,350	$ 25,658
	2003	$ 360,837	$ 350,000		$		$	$ 10,500

and General Counsel	2002	$ 250,008	$ 50,000	$ 36,000	$	$	$	21,857

(1) The amount in this column for 2004 for Messrs. Foshee and Scott reflects a voluntary reduction in annual base salary. For a one-year period beginning on January 1, 2004, Mr. Foshee voluntarily reduced his annual base salary by 30 percent to $630,000. Beginning on June 16, 2004, and for the remainder of 2004, Mr. Scott voluntarily reduced his annual base salary by 30 percent to $379,404. In addition, the amount reflected in this column for 2004, 2003 and 2002 for Messrs. Somerhalder and Baker includes an amount for El Paso mandated reductions to fund certain charitable organizations.

(2) There were no amounts paid for other annual compensation in 2004. The amount reflected for Mr. Baker in 2002 is a $36,000 perquisite and benefit allowance. During 2003, El Paso eliminated perquisite and benefit allowances for its officers and, except as noted, the total value of the perquisites and other personal benefits received by the other executives named in this prospectus in 2003 and 2002 are not included in this column since they were below the SEC s reporting threshold.

(3) In 2004, Ms. Stewart received a grant of 80,000 shares of restricted stock on the start date of her employment and the total value reflected in this column for Ms. Stewart includes the value of those shares on the date of grant. The remainder of the shares of restricted stock granted to the executives named in this prospectus during 2004 are annual grants pursuant to El Paso s long-term incentive compensation plan. The total number of shares and value of restricted stock granted (including the amount reflected in this column) held on December 31, 2004, is as follows:

Restricted Stock as of December 31, 2004

Name	Total Number of Restricted Stock (#)	Value of Restricted Stock ($)
Douglas L. Foshee	267,500	$ 2,782,000
John W. Somerhalder II	158,004	$ 1,643,242
Lisa A. Stewart	150,000	$ 1,560,000
D. Dwight Scott	113,444	$ 1,179,818
Robert W. Baker	102,511	$ 1,066,114

These shares are subject to a time-vesting schedule of three to five years from the date of grant. In addition, most of these shares were granted as a result of the achievement of certain performance measures. Any dividends awarded on the restricted stock are paid directly to the holder of the El Paso common stock. These total values can be realized only if the executives named in this prospectus remain employees of El Paso for the required vesting period.

(4) For 2004 and 2003, the amounts reflected in this column are the value of shares of performance-based restricted stock on the date they vested. These shares of performance-based restricted stock were originally reported, if required, in a long-term incentive table in

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El Paso s proxy statement for the year in which the shares of restricted stock were granted, along with the necessary performance measures for their vesting. No long-term incentive payouts were made in 2002. On the start date of his employment, Mr. Foshee was granted 200,000 shares of performance-based restricted stock. Based on El Paso s performance relative to its peer companies during the first year of Mr. Foshee s employment, 100,000 of the 200,000 shares vested and the remaining 100,000 shares were forfeited. The 100,000 shares that vested based on performance also time vest pro-rata over a five-year period. The first 20,000 shares of restricted stock vested based on time on October 11, 2004, and the value of the shares on the date they vested is reflected in this column for Mr. Foshee for 2004. On February 1, 2001, Mr. Scott was granted 50,000 shares of performance-based restricted stock. These shares time vested over a four-year period. Based on performance, 30,000 of the 50,000 shares vested on October 18, 2004, and the value of the 30,000 shares on the date they vested is reflected in this column for Mr. Scott for 2004. The remaining 20,000 shares were forfeited.

(5) The compensation reflected in this column for 2004 includes El Paso s contributions to the El Paso Retirement Savings Plan and supplemental company match for the Retirement Savings Plan under the Supplemental Benefits Plan and any other special payments, as follows:

El Paso s contributions to the Retirement Savings Plan and Supplemental Company Match under the Supplemental Benefits Plan and Other Special Payments for Fiscal Year 2004

Name	Retirement Savings Plan ($)	Supplemental Benefits Plan ($)	Other Special Payments ($)(a)
Douglas L. Foshee	$ 6,150	$ 45,600	$ 0
John W. Somerhalder II	$ 6,150	$ 40,350	$ 0
Lisa A. Stewart	$ 4,900	$ 11,350	$ 300,000(b)
D. Dwight Scott	$ 6,150	$ 36,675	$ 0
Robert W. Baker	$ 6,150	$ 19,508	$ 0

(a) El Paso does not have a deferred compensation plan for executives and, therefore, does not pay any interest on deferred amounts.

(b) The amount in this column reflects the value of Ms. Stewart s sign-on bonus which was paid to her when she joined El Paso on February 2, 2004.

(6) Mr. Foshee began his employment with El Paso on September 1, 2003.

(7) Mr. Somerhalder ceased to be an employee of El Paso on April 30, 2005.

(8) Ms. Stewart began her employment with El Paso on February 2, 2004.

2005 Compensation Adjustments

On March 28, 2005, our Compensation Committee approved a new annual base salary for three of our named executive officers. The Compensation Committee authorized these base salary adjustments based on competitive market data and commensurate with each executive s job responsibilities and the individual executive s performance.

The new annual base salaries are effective as of April 1, 2005, and are set forth in the table below for each of the named executive officers. The Compensation Committee also authorized the payment of annual cash incentive bonuses for 2004 performance to each of our executive officers based upon both El Paso s performance and that of each of the named executive officers. The Compensation Committee further authorized an annual grant of long-term incentive awards in the form of restricted stock and stock options for each of our named executive officers, which was granted on April 1, 2005. The reasons for the grants as well as the determination of the size of each grant are based upon the Compensation Committee s general executive compensation philosophy.

The following table sets forth information with respect to (i) 2004 annual base salaries and the new annual base salaries that became effective as of April 1, 2005, (ii) the annual cash incentive bonuses that were paid in April for 2004 performance, and (iii) the 2005 annual long-term incentive awards that were granted on April 1, 2005, for each of the following named executive officers.

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Name	2004 Base Salary ($)	2005 Base Salary ($)	Annual Cash Incentive Bonus for 2004 Performance ($)	2005 Annual Long-Term Incentive Award: Stock Options (#)	2005 Annual Long-Term Incentive Award: Restricted Stock (#)
Douglas L. Foshee	$ 900,000	$ 950,004	$ 1,250,000	403,950	194,301
John W. Somerhalder II	$ 642,000	$ 642,000	$ 684,735		
Lisa A. Stewart	$ 500,004	$ 520,008	$ 441,604	121,185	58,290
D. Dwight Scott	$ 542,004	$ 542,004	$ 498,644	121,185	58,290
Robert W. Baker	$ 410,004	$ 426,408	$ 295,203	121,185	58,290

Effective August 10, 2005, the Compensation Committee of our Board of Directors approved a new annual base salary for Mr. Leland payable at a rate of $450,000 and a new target annual cash incentive bonus opportunity for 2005 at a rate of 60% of base salary. Mr. Leland s annual cash incentive bonus may range from a minimum of 0% to a maximum of 135% of base salary depending on the level of both individual and company performance. The Compensation Committee also authorized a grant of long-term incentive awards in the form of stock options to purchase 50,000 shares of our common stock at a price equal to the fair market value of the stock on the date of grant and 25,000 shares of restricted common stock. The stock options will vest in four equal annual installments beginning one year from the date of grant. The restrictions on the shares of restricted stock will lapse in three equal annual installments beginning one year from the date of grant. In addition, Mr. Leland will be eligible to participate in all other plans and programs available to our executive officers, as further described in our 2005 proxy statement.

Stock Option Grants

This table sets forth the number of stock options granted at fair market value to the executives named in this prospectus during the fiscal year 2004. In satisfaction of applicable SEC regulations, the table further sets forth the potential realizable value of such stock options in the year 2014 (the expiration date of the stock options) at an assumed annualized rate of stock price appreciation of five percent and ten percent over the full ten-year term of the stock options. As the table indicates for the grant made on March 8, 2004, annualized stock price appreciation of five percent and ten percent would result in stock prices in the year 2014 of approximately $11.99 and $19.09, respectively. Further as the table indicates for the grant made on April 1, 2004, annualized stock price appreciation of five percent and ten percent would result in stock prices in the year 2014 of approximately $11.55 and $18.39, respectively. The amounts shown in the table as potential realizable values for all stockholders stock (approximately $3.0 billion and $7.6 billion for the March grant and approximately $2.9 billion and $7.3 billion for the April grant) represent the corresponding increases in the market value of 644,932,420 shares of the common stock outstanding as of December 31, 2004. No gain to the executive named in this prospectus is possible without an increase in stock price, which would benefit all stockholders. Actual gains, if any, on stock option exercises and common stock holdings are dependent on the future performance of the common stock and overall stock market conditions. There can be no assurances that the potential realizable values shown in this table will be achieved.

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Option Grants in 2004

	Individual Grants[1]				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
Name	Number of Securities Underlying Options Granted (#)	Percent of Total Options Granted to all Employees in 2004	Exercise Price ($/Share)	Expiration Date	If Stock Price at $11.98866 and $11.54886 in 2014 5% ($)	If Stock Price at $19.08994 and $18.38963 in 2014 10% ($)
Potential Increase in Value of All Common Stock Outstanding on December 31, 2004						
March 8, 2004 Grant	N/A	N/A	N/A	N/A	$ 2,985,175,767	$ 7,565,021,497
April 1, 2004 Grant	N/A	N/A	N/A	N/A	$ 2,875,665,243	$ 7,287,500,328
Douglas L. Foshee	375,000	7.76%	$ 7.09000	4/1/2014	$ 1,672,076	$ 4,237,363
John W. Somerhalder II	140,000	2.90%	$ 7.09000	4/1/2014	$ 624,241	$ 1,581,949
Lisa A. Stewart	155,000	3.21%	$ 7.36000	3/8/2014	$ 717,443	$ 1,818,141
	140,000	2.90%	$ 7.09000	4/1/2014	$ 624,241	$ 1,581,949
D. Dwight Scott	210,000	4.35%	$ 7.09000	4/1/2014	$ 936,361	$ 2,372,923
Robert W. Baker	140,000	2.90%	$ 7.09000	4/1/2014	$ 624,241	$ 1,581,949

[1] There were no stock appreciation rights granted in 2004. Any unvested stock options become fully exercisable in the event of a change in control of El Paso. See page 122 of this prospectus for a description of El Paso s 2001 Omnibus Incentive Compensation Plan and the definition of the term change in control. Under the terms of El Paso s 2001 Omnibus Incentive Compensation Plan, the Compensation Committee may, in its sole discretion and at any time, change the vesting of the stock options. Certain non-qualified stock options may be transferred to immediate family members, directly or indirectly or by means of a trust, corporate entity or partnership. Further, stock options are subject to forfeiture and/or time limitations on exercise in the event of termination of employment.

Option Exercises and Year-End Value Table

This table sets forth information concerning stock option exercises and the fiscal year-end values of the unexercised stock options, provided on an aggregate basis, for each of the executives named in this prospectus.

Aggregated Option Exercises in 2004
and Fiscal Year-End Option Values

Name	Shares Acquired on Exercise (#)[1]	Value Realized ($)[1]	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)[2]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Douglas L. Foshee	0	$ 0	200,000	1,175,000	$ 607,000	$ 3,661,750
John W. Somerhalder II	0	$ 0	439,250	140,000	$ 0	$ 460,600
Lisa A. Stewart	0	$ 0	0	295,000	$ 0	$ 928,700
D. Dwight Scott	0	$ 0	143,494	210,000	$ 8,280	$ 690,900
Robert W. Baker	11,333	$ 80,238	183,709	140,000	$ 0	$ 460,600

(1) The amounts in these columns represent the number of shares and the value realized upon conversion of stock options into shares of stock that occurred during 2004 based upon the achievement of certain performance targets established when they were originally granted in 1999.

(2) The figures presented in these columns have been calculated based upon the difference between $10.38, the fair market value of the common stock on December 31, 2004, for each in-the-money stock option, and its exercise price. No cash is realized until the shares received upon exercise of an option are sold. No executives named in this prospectus had stock appreciation rights that were outstanding on December 31, 2004.

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Pension Plans

Effective January 1, 1997, El Paso amended its Pension Plan to provide pension benefits under a cash balance plan formula that defines participant benefits in terms of a hypothetical account balance. Prior to adopting a cash balance plan, El Paso provided pension benefits under a plan (the Prior Plan) that defined monthly benefits based on final average earnings and years of service. Under the cash balance plan, an initial account balance was established for each El Paso employee who was a participant in the Prior Plan on December 31, 1996. The initial account balance was equal to the present value of Prior Plan benefits as of December 31, 1996.

At the end of each calendar quarter, participant account balances are increased by an interest credit based on 5-Year Treasury bond yields, subject to a minimum interest credit of four percent per year, plus a pay credit equal to a percentage of salary and bonus. The pay credit percentage is based on the sum of age plus service at the end of the prior calendar year according to the following schedule:

Age Plus Service	Pay Credit Percentage
Less than 35	4%
35 to 49	5%
50 to 64	6%
65 and over	7%

Under El Paso s Pension Plan and applicable Internal Revenue Code provisions, compensation in excess of $205,000 cannot be taken into account and the maximum payable benefit in 2004 was $165,000. Any excess benefits otherwise accruing under El Paso s Pension Plan are payable under El Paso s Supplemental Benefits Plan. Participants will receive benefits from the Supplemental Benefits Plan in the form of a lump sum payment unless a valid irrevocable election was made to receive payment in a form other than lump sum prior to June 1, 2004.

Participants with an initial account balance on January 1, 1997 are provided minimum benefits equal to the Prior Plan benefit accrued as of the end of 2001. Upon retirement, certain participants are provided pension benefits that equal the greater of the cash balance formula benefit or the Prior Plan benefit. For Mr. Somerhalder, the Prior Plan benefit reflects accruals through the end of 2001 and is computed as follows: for each year of credited service up to a total of 30 years, 1.1 percent of the first $26,800, plus 1.6 percent of the excess over $26,800, of the participant s average annual earnings during his five years of highest earnings.

Credited service as of December 31, 2001, for Mr. Somerhalder is reflected in the table below. Amounts reported under Salary and Bonus for each executive named in this prospectus approximate earnings as defined under the Pension Plan.

Estimated annual benefits payable from the Pension Plan and Supplemental Benefits Plan upon retirement at the normal retirement age (age 65) for each executive named in this prospectus is reflected below (based on assumptions that each executive receives base salary shown in the Summary Compensation Table with no pay increases, receives target annual bonuses beginning with bonuses earned for fiscal year 2005, and cash balances are credited with interest at a rate of four percent per annum):

Named Executive	Credited Service[1]	Pay Credit Percentage During 2004	Estimated Annual Benefits ($)[2]
Douglas L. Foshee	N/A	5%	$$330,053
John W. Somerhalder II	24	7%	$$402,152
Lisa A. Stewart	N/A	5%	$$140,639
D. Dwight Scott	N/A	5%	$$261,592
Robert W. Baker	N/A	7%	$$142,601

(1) For Mr. Somerhalder, credited service shown is as of December 31, 2001.

(2) The Prior Plan minimum benefit for Mr. Somerhalder is greater than his projected cash balance benefit at age 65. As of his termination date, Mr. Somerhalder s vested pension benefit amount under the Prior Plan is estimated to be $212,414, payable commencing at age 49 as an immediate lump sum. Mr. Somerhalder will receive his Supplemental Benefits Plan benefit in a lump sum of approximately $1.77 million, minus amounts withheld for taxes.

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Employment Contracts, Termination of Employment, Change in Control Arrangements, and Director and Officer Indemnification Agreements

Employment Agreements

Douglas L. Foshee entered into a letter agreement with El Paso effective September 1, 2003. Under this agreement, Mr. Foshee serves as President, Chief Executive Officer and a director of El Paso and receives an annual salary of $900,000 (which Mr. Foshee voluntarily reduced for 2004 to $630,000). Mr. Foshee is also eligible to earn a target bonus amount equal to 100 percent of his annual salary (a maximum bonus of 225 percent of salary) based on El Paso s and his performance as determined by the Compensation Committee. Mr. Foshee also receives the employee benefits which are available to senior executive officers. In addition, on the start date of his employment, Mr. Foshee was granted 1,000,000 options to purchase El Paso common stock and 200,000 shares of restricted stock. The options will time vest pro-rata over a five-year period. The shares of restricted stock have both time and performance vesting provisions. Based on El Paso s performance relative to its peer companies during the first year, 100,000 of the 200,000 shares of restricted stock vested and the remaining 100,000 shares were forfeited. The 100,000 shares that vested based on performance also time vest pro-rata over a five-year period. The first 20,000 shares of restricted stock vested based on time on October 11, 2004. In addition, on his start date, Mr. Foshee received common stock with a value of $875,000 and an additional cash payment of $875,000. Mr. Foshee may not pledge or sell the common stock received as part of the sign-on bonus for a period of two years from the grant date. If Mr. Foshee s employment is involuntarily terminated not for cause, Mr. Foshee will receive a lump sum payment of two years base pay and target bonus. In the event he is terminated within two years of a change in control (or terminates employment for good reason), Mr. Foshee will receive a lump sum payment of three years annual salary and target bonus (plus a pro-rated portion of his target bonus).

As part of the merger with Sonat, El Paso entered into a termination and consulting agreement with Ronald L. Kuehn, Jr., dated October 25, 1999. Under this agreement, and for the remainder of his life, Mr. Kuehn will receive certain ancillary benefits made available to him prior to the merger with Sonat, including the provision of office space and related services, and payment of life insurance premiums sufficient to provide a death benefit equal to four times his base pay as in effect immediately prior to October 25, 1999. Mr. Kuehn and his eligible dependents will also receive retiree medical coverage.

Effective April 30, 2005, John W. Somerhalder II entered into an agreement and general release, dated May 4, 2005, pursuant to which Mr. Somerhalder s separation of employment with El Paso became effective. Under this agreement, El Paso agreed to provide severance benefits to Mr. Somerhalder under El Paso s existing severance pay plan in the amount of $642,000. El Paso also agreed to provide Mr. Somerhalder with a prorationing of his incentive compensation for 2005, which included one third of his target 2005 annual cash incentive bonus in the amount of $203,300, a cash equivalent in the amount of $12,815 equal to the pro-rated value of his 2005 equity award had he received that grant, and eight months of continued medical coverage subject to the payment of the required contributions. Upon his departure, Mr. Somerhalder had 95,000 vested non-qualified stock options and 49,531 shares of vested restricted stock. These awards are subject to terms of the original grant and the plans under which the awards were granted. In addition, El Paso entered into a consulting agreement with Mr. Somerhalder pursuant to which Mr. Somerhalder will provide consulting services to El Paso on various pipeline projects for a fee of $41,000 per month for a period of 12 months, subject to certain earlier termination rights set forth in the consulting agreement.

Benefit Plans

Severance Pay Plan. The Severance Pay Plan is a broad-based employee plan providing severance benefits following a qualifying termination for all salaried employees of El Paso and certain of its subsidiaries. The plan also included an executive supplement, which provided enhanced severance benefits for certain executive officers of El Paso and certain of its subsidiaries, including all of the executives named in this prospectus. The enhanced severance benefits available under the supplement included an amount equal to two times the sum of the officer s annual salary, including annual target bonus amounts as specified in the plan. A qualifying termination included an involuntary termination of the officer as a result of the elimination of the

officer s position or a reduction in force and a termination for good reason (as defined under the plan). The executive supplement of the Severance Pay Plan terminated on January 1, 2005. Accordingly, the executives will receive severance pay pursuant to the Severance Pay Plan which covers all employees of El Paso and provides for severance benefits in a lesser amount than the executive supplement.

2004 Key Executive Severance Protection Plan. El Paso periodically reviews its benefit plans and engages an independent executive compensation consultant to make recommendations regarding its plans. Our executive compensation consultant recommended that El Paso adopt a new executive severance plan that more closely aligns with current market arrangements than El Paso s Key Executive Severance Protection Plan and Employee Severance Protection Plan (as described below). In light of this recommendation, El Paso adopted this plan in March 2004. This plan provides severance benefits following a change in control of El Paso for executives of El Paso and certain of its subsidiaries designated by the Board or the Compensation Committee, including Mr. Foshee, Ms. Stewart and Messrs. Scott and Baker. This plan is intended to replace the Key Executive Severance Protection Plan and the Employee Severance Protection Plan, and participants are required to waive their participation under those plans (if applicable) as a condition to becoming participants in this plan. The benefits of the plan include: (1) a cash severance payment in an amount equal to three times the annual salary and target bonus for Mr. Foshee, two times the annual salary and target bonus for executive vice presidents and senior vice presidents, including Ms. Stewart and Messrs. Scott and Baker, and one times the annual salary and target bonus for vice presidents; (2) a pro-rated portion of the executive s target bonus for the year in which the termination of employment occurs; (3) continuation of life and health insurance following termination for a period of 36 months for Mr. Foshee, 24 months for executive vice presidents and senior vice presidents, including Ms. Stewart and Messrs. Scott and Baker, and 12 months for vice presidents; (4) a gross-up payment for any federal excise tax imposed on an executive in connection with any payment or distribution made by El Paso or any of its affiliates under the plan or otherwise; provided that in the event a reduction in payments in respect of the executive of ten percent or less would cause no excise tax to be payable in respect of that executive, then the executive will not be entitled to a gross-up payment and payments to the executive shall be reduced to the extent necessary so that the payments shall not be subject to the excise tax; and (5) payment of legal fees and expenses incurred by the executive to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment of an executive in the plan within two years following the date of a change in control, except where termination is by reason of death, disability, for cause (as defined in the plan) or instituted by the executive other than for good reason (as defined in the plan). Benefits are also payable under the plan for terminations of employment prior to a change in control that arise in connection with, or in anticipation of, a change in control. Benefits are not payable for any termination of employment following a change in control if (i) the termination occurs in connection with the sale, divestiture or other disposition of designated subsidiaries of El Paso, (ii) the purchaser or entity subject to the transaction agrees to provide severance benefits at least equal to the benefits available under the plan, and (iii) the executive is offered, or accepts, employment with the purchaser or entity subject to the transaction. A change in control generally occurs if: (i) any person or entity becomes the beneficial owner of more than 20 percent of El Paso s common stock; (ii) a majority of the current members of the Board of Directors of El Paso or their approved successors cease to be directors of El Paso (or, in the event of a merger, the ultimate parent following the merger); or (iii) a merger, consolidation, or reorganization of El Paso, a complete liquidation or dissolution of El Paso, or the sale or disposition of all or substantially all of El Paso s and its subsidiaries assets (other than a transaction in which the same stockholders of El Paso before the transaction own 50 percent of the outstanding common stock after the transaction is complete). This plan generally may be amended or terminated at any time prior to a change in control, provided that any amendment or termination that would adversely affect the benefits or protections of any executive under the plan shall be null and void as it relates to that executive if a change in control occurs within one year of the amendment or termination. In addition, any amendment or termination of the plan in connection with, or in anticipation of, a change in control which actually occurs shall be null and void. From and after a change in control, the plan may not be amended in any manner that would adversely affect the benefits or protections provided to any executive under the plan.

Key Executive Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a change in control of El Paso for certain officers of El Paso and certain of its subsidiaries.

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The benefits of the plan include: (1) an amount equal to three times the participant s annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination; (3) a supplemental pension payment calculated by adding three years of additional credited pension service; (4) certain additional payments to the terminated employee to cover excise taxes if the payments made under the plan are subject to excise taxes on golden parachute payments; and (5) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control, except where termination is by reason of death, disability, for cause or instituted by the employee for other than good reason (as defined in the plan). A change in control occurs if: (i) any person or entity becomes the beneficial owner of 20 percent or more of El Paso s common stock; (ii) any person or entity (other than El Paso) purchases the common stock by way of a tender or exchange offer; (iii) El Paso stockholders approve a merger or consolidation, sale or disposition or a plan of liquidation or dissolution of all or substantially all of El Paso s assets; or (iv) if over a two year period a majority of the members of the Board of Directors at the beginning of the period cease to be directors. A change in control has not occurred if El Paso is involved in a merger, consolidation or sale of assets in which the same stockholders of El Paso before the transaction own 80 percent of the outstanding common stock after the transaction is complete. This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants rights under the plan or be made following the occurrence of a change in control. This plan is closed to new participants, unless the Board determines otherwise.

Employee Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a change in control (as defined in the Key Executive Severance Protection Plan) of El Paso for certain salaried, non-executive employees of El Paso and certain of its subsidiaries. The benefits of the plan include: (1) severance pay based on the formula described below, up to a maximum of two times the participant s annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination (plus an additional payment, if necessary, equal to any additional income tax imposed on the participant by reason of his or her continued life and health insurance coverage); and (3) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. The formula by which severance pay is calculated under the plan consists of the sum of: (i) one-twelfth of a participant s annual salary and maximum bonus for every $7,000 of his or her annual salary and maximum bonus, but no less than five-twelfths nor more than the entire salary and bonus amount, and (ii) one-twelfth of a participant s annual salary and maximum bonus for every year of service performed immediately prior to a change in control. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control, except where termination is by reason of death, disability, for cause or instituted by the employee for other than good reason (as defined in the plan). This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants rights under the plan or be made following the occurrence of a change in control. This plan is closed to new participants, unless the Board determines otherwise.

Supplemental Benefits Plan. This plan provides for certain benefits to officers and key management employees of El Paso and its subsidiaries. The benefits include: (1) a credit equal to the amount that a participant did not receive under El Paso s Pension Plan because the Pension Plan does not consider deferred compensation (whether in deferred cash or deferred restricted common stock) for purposes of calculating benefits and eligible compensation is subject to certain Internal Revenue Code limitations; and (2) a credit equal to the amount of El Paso s matching contribution to El Paso s Retirement Savings Plan that cannot be made because of a participant s deferred compensation and Internal Revenue Code limitations. The plan may not be terminated so long as the Pension Plan and/or Retirement Savings Plan remain in effect. The management committee of this plan designates who may participate and also administers the plan. Benefits under El Paso s Supplemental Benefits Plan are paid upon termination of employment in a lump-sum payment. In the event of a change in control (as defined under the Key Executive Severance Protection Plan)

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of El Paso, the supplemental pension benefits become fully vested and nonforfeitable. El Paso s payment obligations under the Supplemental Benefits Plan as of December 31, 2004, are as follows:

Payment Obligations under the Supplemental Benefits Plan as of December 31, 2004

Name	Retirement Savings Plan	Non-Qualified Pension Benefit[1]
Douglas L. Foshee	$ 48,513	$ 76,451
John W. Somerhalder II	$ 54,488	$ 1,774,503
Lisa A. Stewart	$ 11,350	$ 12,826
D. Dwight Scott	$ 48,450	$ 107,578
Robert W. Baker	$ 27,195	$ 114,818

(1) This amount is included in the calculation of the estimated annual benefits described under Pension Plans on page 131 of this prospectus.

Senior Executive Survivor Benefits Plan. This plan provides certain senior executives (including each of the executives named in this prospectus) of El Paso and its subsidiaries who are designated by the plan administrator with survivor benefit coverage in lieu of the coverage provided generally for employees under El Paso s group life insurance plan. The amount of benefits provided, on an after-tax basis, is two and one-half times the executive s annual salary. Benefits are payable in installments over 30 months beginning within 31 days after the executive s death, except that the plan administrator may, in its discretion, accelerate payments.

Benefits Protection Trust Agreement. El Paso maintains a trust for the purpose of funding certain of its employee benefit plans (including the severance protection plans described above). The trust consists of a trustee expense account, which is used to pay the fees and expenses of the trustee, and a benefit account, which is made up of three subaccounts and used to make payments to participants and beneficiaries in the participating plans. The trust is revocable by El Paso at any time before a threatened change in control (which is generally defined to include the commencement of actions that would lead to a change in control (as defined under the Key Executive Severance Protection Plan)) as to assets held in the trustee expense account, but is not revocable (except as provided below) as to assets held in the benefit account at any time. The trust generally becomes fully irrevocable as to assets held in the trust upon a threatened change in control. The trust is a grantor trust for federal tax purposes, and assets of the trust are subject to claims by El Paso s general creditors in preference to the claims of plan participants and beneficiaries. Upon a threatened change in control, El Paso must deliver $1.5 million in cash to the trustee expense account. Prior to a threatened change in control, El Paso may freely withdraw and substitute the assets held in the benefit account, other than the initially funded amount; however, no such assets may be withdrawn from the benefit account during a threatened change in control period. Any assets contributed to the trust during a threatened change in control period may be withdrawn if the threatened change in control period ends and there has been no threatened change in control. In addition, after a change in control occurs, if the trustee determines that the amounts held in the trust are less than designated percentages (as defined in the Trust Agreement) with respect to each subaccount in the benefit account, the trustee must make a written demand on El Paso to deliver funds in an amount determined by the trustee sufficient to attain the designed percentages. Following a change in control and if the trustee has not been requested to pay benefits from any subaccount during a determination period (as defined in the Trust Agreement), El Paso may make a written request to the trustee to withdraw certain amounts which were allocated to the subaccounts after the change in control occurred. The trust generally may be amended or terminated at any time, provided that no amendment or termination may result, directly or indirectly, in the return of any assets of the benefit account to El Paso prior to the satisfaction of

all liabilities under the participating plans (except as described above) and no amendment may be made unless El Paso, in its reasonable discretion, believes that such amendment would have no material adverse effect on the amount of benefits payable under the trust to participants. In addition, no amendment may be made after

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the occurrence of a change in control which would (i) permit El Paso to withdraw any assets from the trustee expense account, (ii) directly or indirectly reduce or restrict the trustee s rights and duties under the trust, or (iii) permit El Paso to remove the trustee following the date of the change in control.

Director and Officer Indemnification Agreements

El Paso has entered into indemnification agreements with each member of the Board of Directors and certain officers, including each of the executives named in this prospectus. These agreements reiterate the rights to indemnification that are provided to our Board of Directors and certain officers under El Paso s By-laws, clarify procedures related to those rights, and provide that such rights are also available to fiduciaries under certain of El Paso s employee benefit plans. As is the case under the By-laws, the agreements provide for indemnification to the full extent permitted by Delaware law, including the right to be paid the reasonable expenses (including attorneys fees) incurred in defending a proceeding related to service as a director, officer or fiduciary in advance of that proceedings final disposition. El Paso may maintain insurance, enter into contracts, create a trust fund or use other means available to provide for indemnity payments and advances. In the event of a change in control of El Paso (as defined in the indemnification agreements), El Paso is obligated to pay the costs of independent legal counsel who will provide advice concerning the rights of each director and officer to indemnity payments and advances.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions, we have been informed that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of May 15, 2005 (unless otherwise noted) regarding beneficial ownership of common stock by each director and nominee, our Chief Executive Officer, the other four most highly compensated executive officers in the last fiscal year, our directors and executive officers as a group and each person or entity known by El Paso to own beneficially more than five percent of its outstanding shares of common stock. No family relationship exists between any of the directors or executive officers of El Paso.

Title of Class	Name of Beneficial Owner	Beneficial Ownership (Excluding Options)[1]	Stock Options[2]	Total	Percent of Class
Common Stock	Pacific Financial Research Inc.(3) 9601 Wilshire Boulevard, Suite 800 Beverly Hills, CA 90210	78,130,889	0	78,130,889	12.10%
Common Stock	Brandes Investment Partners, L.L.C.(3) 11988 El Camino Real Suite 500 San Diego, CA 92130	71,441,912	0	71,441,912	11.06%
Common Stock	State Street Bank and Trust Company(3) P.O. Box 1389 Boston, MA 02104-1389	32,321,279	0	32,321,279	5.01%
Common Stock	J.M. Bissell	76,082	12,000	88,082	*
Common Stock	J.C. Braniff	74,834(4)	21,000	95,834	*
Common Stock	J.L. Dunlap	36,986(5)	8,000	44,986	*
Common Stock	R.W. Goldman	40,974	8,000	48,974	*
Common Stock	A.W. Hall, Jr.	50,614	12,000	62,614	*
Common Stock	T.R. Hix	17,226	0	17,226	*
Common Stock	W.H. Joyce	18,226	0	18,226	*
Common Stock	R.L. Kuehn, Jr.	325,362(6)	502,300	827,662	*
Common Stock	J.M. Talbert	29,084	8,000	37,084	*
Common Stock	R.F. Vagt	3,000	0	3,000	*
Common Stock	J.L. Whitmire	47,605	8,000	55,605	*
Common Stock	J.B. Wyatt	63,065	14,000	77,065	*
Common Stock	D.L. Foshee	573,431	293,750	867,181	*
Common Stock	J.W. Somerhalder II	357,154(7)	95,000	452,154	*
Common Stock	L.A. Stewart	196,212(8)	73,750	269,962	*
Common Stock	D.D. Scott	190,203	195,994	386,197	*
Common Stock	R.W. Baker	184,456	218,709	403,165	*
Common Stock	Directors, nominee and executive officers as a group (17 persons total), including those individuals listed above	2,284,514	1,470,503	3,755,017	0.58%

* Less than one percent

(1) The individuals named in the table have sole voting and investment power with respect to shares of El Paso common stock beneficially owned, except that Mr. Talbert shares with one or more other individuals voting and investment power with respect to 5,000 shares of common stock. This column also includes shares of common stock held in the El Paso Benefits Protection Trust (as of March 15, 2005) as a result of deferral elections made in accordance with El Paso s benefit plans. These individuals share voting power with the trustee under that plan and receive dividend equivalents on such shares, but do not have the power to dispose of, or direct the disposition of, such shares until such shares are distributed. In addition, some shares of common stock reflected in this column for certain individuals are subject to restrictions.

(2) The directors and executive officers have the right to acquire the shares of common stock reflected in this column within 60 days of March 15, 2005, through the exercise of stock options.

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(3) According to a Schedule 13G filed on February 11, 2005, as of December 31, 2004, Pacific Financial Research Inc. had sole voting power over 73,376,789 shares of common stock, no voting power over 4,754,100 shares of common stock and sole dispositive power of 78,130,889 shares of common stock. According to a Schedule 13G filed on February 14, 2005, as of December 31, 2004, Brandes Investment Partners, L.L.C. had shared voting power of 55,594,630 shares of common stock and shared dispositive power over 71,441,912 shares of common stock. According to a Schedule 13G/ A filed on February 18, 2005, as of December 31, 2004, State Street Bank and Trust Company had sole voting power over 17,728,241 shares of common stock, shared voting power over 14,593,038 shares of common stock and shared dispositive power of 32,321,279 shares of common stock.

(4) Mr. Braniff s beneficial ownership excludes 3,500 shares owned by his wife. Mr. Braniff disclaims any beneficial ownership in those shares.

(5) Mr. Dunlap s beneficial ownership excludes 900 shares held by his wife as trustee. Mr. Dunlap disclaims any beneficial ownership in those shares.

(6) Mr. Kuehn s beneficial ownership excludes 28,720 shares owned by his wife or children. Mr. Kuehn disclaims any beneficial ownership in those shares.

(7) Mr. Somerhalder s stock ownership is as of April 30, 2005, when he left the company.

(8) Ms. Stewart s beneficial ownership includes 216 shares held by her husband.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

See Executive Compensation Employment Contracts, Termination of Employment, Change in Control Arrangements, and Director and Officer Indemnification Agreements starting on page 132 of this prospectus.

DESCRIPTION OF EL PASO CAPITAL STOCK

General

As of August 2, 2005, there were 645,719,039 shares of our common stock issued and outstanding and 750,000 shares of our preferred stock issued and outstanding. The statements under this caption are brief summaries and are subject to, and are qualified in their entirety by reference to, the more complete descriptions contained in our Amended and Restated Certificate of Incorporation, which we refer to as our charter.

Common Stock

We are currently authorized by our Charter to issue up to 1,500,000,000 shares of common stock. The holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of stockholders. Holders of common stock do not have the right to cumulate votes in the election of directors. Subject to preferences that may be applicable to any outstanding preferred stock, holders of common stock are entitled to receive ratably dividends which are declared by our board of directors out of funds legally available for such a purpose. In the event of our liquidation, dissolution, or winding up, holders of common stock are entitled to share ratably in all assets remaining after payment of liabilities and liquidation preference of any outstanding preferred stock. Holders of common stock have no preemptive rights and have no rights to convert their common stock into any other securities. The common stock is not redeemable. All of the outstanding shares of common stock are fully paid and nonassessable upon issuance against full payment of the purchase price.

EquiServe Trust Company, N.A. is the transfer agent and registrar for our common stock.

Preferred Stock

Our board of directors, without any further action by our stockholders, is authorized to issue up to 50,000,000 shares of preferred stock, and to divide the preferred stock into one or more series. The Board may fix by resolution or resolutions any of the designations and the powers, preferences and rights, and the qualifications, limitations, or restrictions which are permitted by the General Corporation Law of the State of Delaware of the shares of each such series. Preferred stock, upon issuance against full payment of the

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purchase price therefor, will be fully paid and nonassessable. The issuance of preferred stock may have the effect of delaying, deterring or preventing a change in control of El Paso. The specific terms of a particular series of preferred stock will be described in the certificate of designation relating to that series. The designations, powers, preferences and rights, and the qualifications, limitations, or restrictions of the preferred stock will vary depending on the series, therefore reference to the certificate of designation relating to that particular series of preferred stock should be made for a complete description of terms.

As of the date of this prospectus, a total of 750,000 shares of our preferred stock is issued and outstanding.

On April 15, 2005, we issued 750,000 shares of 4.99% Convertible Perpetual Preferred Stock (the Preferred Stock). The Preferred Stock has a liquidation preference of $1,000 per share. Holders of the Preferred Stock are entitled to receive, when, as and if declared by our board of directors, out of funds legally available therefore, cash dividends at the rate of 4.99% per year, payable in arrears on January 1, April 1, July 1 and October 1 of each year, beginning on July 1, 2005. Dividends on the Preferred Stock will be cumulative from the date of issuance. Accumulated but unpaid dividends cumulate at the annual rate of 4.99%.

The Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion rate of 76.7754 shares of common stock per share of Preferred Stock, which represents an initial conversion price of approximately $13.03 per share of common stock, subject to specified adjustments. Upon the occurrence of certain events prior to April 1, 2015, holders of the Preferred Stock may, subject to certain conditions, require us to redeem any or all of their shares of Preferred Stock by paying cash in an amount equal to the liquidation preference, plus any accumulated and unpaid dividends, including liquidated damages, if any. In certain circumstances, a holder of Preferred Stock who elects to convert upon the occurrence of certain events prior to April 5, 2015 will be entitled to receive, in addition to the number of shares of common stock equal to the applicable conversion rate, an additional number of shares of common stock.

On or after April 5, 2010, if the closing price of our common stock equals or exceeds 130% of the then prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days, we will be able to cause the Preferred Stock to be converted into shares of common stock at the then prevailing conversion rate.

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, 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 the Preferred Stock (voting separately as a class with all other series of preferred stock on parity with the Preferred Stock upon which like voting rights have been conferred and are exercisable) will be entitled to vote for the election of two of the authorized number of our directors at the next annual meeting of shareholders and at each subsequent meeting until all accumulated and unpaid dividends or the redemption price on the Preferred Stock have been fully paid or set aside for payment. Each holder of Preferred Stock will have one vote for each share of Preferred Stock held. The term of office of all directors elected by the holders of the Preferred Stock will terminate immediately upon the termination of the right of holders of the Preferred Stock to vote for directors.

The Preferred Stock, with respect to dividend rights and upon liquidation, winding up and dissolution, ranks: junior to all of our existing and future debt obligations; junior to all classes 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

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effectively junior to all of our subsidiaries (1) existing and future liabilities and (2) capital stock held by others.

On April 14, 2005, the Company filed with the Secretary of State of the State of Delaware the Certificate of Designations of the Preferred Stock. A copy of the Certificate of Designations is included as Exhibit 4.B to the registration statement of which this prospectus is a part.

Section 203 of the Delaware General Corporation Law

We are a Delaware corporation subject to Section 203 of the Delaware General Corporation Law. Generally, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the time of the transaction in which the person became an interested stockholder, unless (1) prior to such time, either the business combination or such transaction which resulted in the stockholder becoming an interested stockholder is approved by the board of directors of the corporation, (2) upon consummation of the transaction which resulted in the stockholder becoming an interested stockholder, the interested stockholder owns at least 85% of the outstanding voting stock, or (3) at or subsequent to such time, the business combination is approved by the board of directors of the corporation and by the affirmative vote at least $66^2/3\%$ of the outstanding voting stock that is not owned by the interested stockholder. A business combination includes mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. An interested stockholder is a person who, together with affiliates and associates, owns, or, within three years, did own, 15% or more of the corporation s outstanding voting stock.

El Paso s Restated Certificate of Incorporation and By-laws

The following provisions in our charter or by-laws may make a takeover of El Paso more difficult:

- our charter prohibits the taking of any action by written stockholder consent in lieu of a meeting;
- our by-laws provide that special meetings of stockholders may be called only by a majority of the Board, the Chairman of the Board, the Chief Executive Officer, the President or the Vice Chairman of the Board; and
- our by-laws establish an advance notice procedure for stockholders to make nominations of candidates for election as directors or to bring other business before an annual meeting of stockholders.

DESCRIPTION OF THE EQUITY SECURITY UNITS

We summarize below the principal terms of the ESUs and the purchase contracts and senior notes which comprise the ESUs. The following description is only a summary. You should read these descriptions together with the purchase contract agreement, the senior indenture, the pledge agreement and the remarketing agreement, as well as the Trust Indenture Act, for a complete understanding of the provisions that may be important to you. See Where You Can Find More Information for more information about how to obtain a copy of those documents, as well as a form of certificate evidencing the ESUs, a form of certificate evidencing the stripped units (described below) and a form of senior note, all of which are included or incorporated by reference as exhibits to the registration statement of which this prospectus is a part.

Overview

We originally issued a total of 11,550,000 ESUs, of which 5,442,040 ESUs remain issued and outstanding. Each ESU, or normal unit, was issued at the stated amount of $50 and initially consisted of:

(1) a purchase contract under which:

holders agreed to purchase, and we agreed to sell, for $50, shares of our common stock on the stock purchase date, the number of which will be determined by the settlement rate described

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below, based on the average trading price of our common stock for a period preceding that date; and

we agreed to pay you quarterly contract adjustment payments at the annual rate of 2.86% of the $50 stated amount as further described below, subject to our right to deferral as described below; and

(2) a senior note due August 16, 2007 with a principal amount of $50, on which we pay interest quarterly at the annual rate of 6.14% until the earlier of the date of settlement of a successful remarketing of the senior notes (which is the third business day after such remarketing) and the stock purchase date, after which we will pay interest at the reset rate.

The senior notes that were initially held as part of the normal units were initially pledged to us as collateral to secure the holders obligations under the purchase contracts. Concurrently with the successful remarketing on July 1, 2005, the senior notes pledged as collateral were substituted and replaced with zero-coupon U.S. Treasury securities maturing on August 15, 2005 in the full amount of approximately $275.4 million. These U.S. Treasury securities are now pledged to us as collateral to secure the holders obligations under the purchase contracts.

A beneficial owner of ESUs is deemed to have:

irrevocably agreed to be bound by the terms of the purchase contract agreement, pledge agreement and purchase contract for so long as it remains a beneficial owner of such ESU; and

appointed the purchase contract agent under the purchase contract agreement as its agent and attorney-in-fact to enter into and perform the purchase contract on its behalf.

In addition, a beneficial owner of a normal unit, is deemed by its acceptance of the normal unit to have agreed to treat itself as the owner of the related senior notes (or after a successful remarketing (which is now the case), the specified portfolio of treasury securities, or tax event redemption, the specified tax event portfolio of treasury securities) and to treat the senior notes as our indebtedness.

At the closing of the offering of the normal units, the underwriters purchased the normal units. The purchase price of each normal unit was allocated by us between the related purchase contract and the related senior note. The senior notes were then pledged to the collateral agent to secure the holders obligations owed to us under the purchase contracts.

We entered into:

a purchase contract agreement with HSBC Bank USA, National Association (successor-in-interest to JPMorgan Chase Bank), as purchase contract agent, governing, among other things, the appointment of the purchase contract agent as the agent and attorney-in-fact for the holders of the ESUs, the purchase contracts, the transfer, exchange or replacement of certificates representing the ESUs and certain other matters relating to the ESUs; and

a pledge agreement with The Bank of New York Trust Company, N.A., as collateral agent and securities intermediary creating a pledge and security interest for our benefit to secure the obligations of holders of ESUs under the purchase contracts. The pledge agreement also provides for The Bank of New York to act as custodial agent with respect to the senior notes that are held separately and participating in a remarketing.

Quarterly Payments

Holders of normal units receive:

quarterly contract adjustment payments on the purchase contract at the annual rate of 2.86% of the $50 stated amount on all quarterly payment dates on or before the stock purchase date, subject to our right of deferral; and

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quarterly interest payments on the pledged senior note at the annual rate of 6.14% of the $50 principal amount for the quarterly interest payments that became due on or before May 16, 2005. However, because of the successful remarketing of the pledged notes, on July 1, 2005, the pledged notes were replaced as collateral by a portfolio of U.S. treasury obligations. Therefore, on August 16, 2005, you will now receive a quarterly payment on the pledged portfolio of treasury securities that were substituted for the senior note at an annual rate of 6.14%.

Holders of senior notes purchased in the remarketing of the pledged notes will receive quarterly interest at an annual rate of 7.625%, except for the interest payment due on August 16, 2005 which will be at the annual rate of 6.14% for the period from May 16, 2005 to but excluding July 1, 2005, and at the reset rate of 7.625% from and including July 1, 2005 to but excluding August 16, 2005. The remarketed notes will mature on August 16, 2007.

Our obligations with respect to the contract adjustment payments and the senior notes are unsecured and rank equally with all our other existing and future unsecured and unsubordinated indebtedness.

If the purchase contracts are settled early (at the holders option) or terminated (upon the occurrence of certain events of bankruptcy, insolvency or reorganization with respect to us), holders will have no right to receive any accumulated and unpaid contract adjustment payments or deferred contract adjustment payments.

Option to Defer Contract Adjustment Payments

We may, at our option and upon prior written notice to the holders of the ESUs and the purchase contract agent, defer the payment of contract adjustment payments on the related purchase contracts until no later than the stock purchase date. We will pay additional contract adjustment payments on any deferred installments of contract adjustment payments at the rate of 6.14% per year (compounded quarterly) until paid. However, if a purchase contract is settled early or terminated (upon the occurrence of certain events of bankruptcy, insolvency or reorganization with respect to us), the right to receive accumulated and unpaid contract adjustment payments and deferred contract adjustment payments will terminate. To date, we have not elected to exercise our deferral rights.

If we elect to defer the payment of contract adjustment payments on the purchase contracts until the stock purchase date, we may elect to pay each holder of ESUs on the stock purchase date in respect of the deferred contract adjustment payments, in lieu of a cash payment, a number of shares of our common stock equal to (a) the aggregate amount of deferred contract adjustment payments payable to the holder divided by (b) the applicable market value (as defined below under Description of the Purchase Contracts). If we elect to pay deferred contract adjustment payments on the stock purchase date in common stock, we will not issue any fractional shares of our common stock. In lieu of fractional shares otherwise issuable with respect to such payment of deferred contract adjustment payments, the holder will be entitled to receive an amount in cash equal to the fraction of a share times the applicable market value.

In general, if we exercise our option to defer the payment of contract adjustment payments, then until the deferred contract adjustment payments have been paid, we will not declare or pay dividends on, make distributions with respect to, or redeem, purchase or acquire, or make a liquidation payment with respect to, any class of our common stock, subject to specified exceptions.

Description of the Purchase Contracts

Each purchase contract underlying an ESU, unless earlier settled or terminated, will obligate the holder thereof to purchase, and us to sell, for $50, on the stock purchase date, a number of newly issued shares of our common stock equal to the settlement rate.

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The settlement rate, which is the number of newly issued shares of our common stock issuable upon settlement of a purchase contract on the stock purchase date, subject to adjustment under certain circumstances as described under Anti-dilution Adjustments below, will be as follows:

If the applicable market value of our common stock is equal to or greater than the threshold appreciation price of $23.94, which is approximately 20% above the reference price of $19.95, the settlement rate, which is equal to the stated amount of $50 divided by $23.94, will be 2.0886 shares of our common stock per purchase contract. Accordingly, if the market price for our common stock increases to an amount that is greater than $23.94 on the stock purchase date, the aggregate market value of the shares of common stock issued upon settlement of each purchase contract, assuming that this market value is the same as the applicable market value of our common stock, will be greater than $50, and if the market price equals $23.94, the aggregate market value of those shares, assuming that this market value is the same as the applicable market value of our common stock, will equal $50.

If the applicable market value of our common stock is less than $23.94 but greater than $19.95, the settlement rate will be equal to the stated amount of $50 divided by the applicable market value of our common stock per purchase contract. Accordingly, if the market price for our common stock increases, but that market price is less than $23.94 on the stock purchase date, the aggregate market value of the shares of common stock issued upon settlement of each purchase contract, assuming that this market value is the same as the applicable market value of our common stock, will equal $50.

If the applicable market value of our common stock is less than or equal to $19.95, the settlement rate, which is equal to the stated amount of $50 divided by $19.95, will be 2.5063 shares of our common stock per purchase contract. Accordingly, if the market price for our common stock decreases to an amount that is less than $19.95 on the stock purchase date, the aggregate market value of the shares of our common stock issued upon settlement of each purchase contract, assuming that the market value is the same as the applicable market value of our common stock, will be less than $50, and if the market price equals $19.95, the aggregate market value of those shares, assuming that this market value is the same as the applicable market value of our common stock, will equal $50.

The applicable market value of our common stock is the average of the closing prices per share of our common stock on each of the 20 consecutive trading days ending on the third trading day immediately preceding the stock purchase date; *provided,* that, in the case of a merger early settlement, the 20 consecutive trading days shall end on the date of completion of the cash merger.

Settlement

Settlement of the purchase contracts will occur on the stock purchase date, unless:

holders of the purchase contracts have settled the purchase contract not later than 11:00 a.m., New York City time, on the eleventh business day immediately preceding the stock purchase date through the early delivery of cash to the purchase contract agent, as described in Early Settlement;

we are involved in a merger prior to the stock purchase date in which at least 30% of the consideration for our common stock consists of cash or cash equivalents, and holders of the purchase contracts have settled the related purchase contract through an early settlement, as described in Early Settlement upon Cash Merger; or

an event described under Termination of Purchase Contracts has occurred.

The settlement of the purchase contracts on the stock purchase date will occur as follows:

for normal units, which now include the pledged specified portfolio of treasury securities, the cash received upon the maturity of the treasury securities will automatically be applied to satisfy in full the holder s obligation to purchase shares of our common stock under the purchase contracts and to pay an amount to such holder based on the initial annual rate on the senior notes; and

for normal units the holders of which have settled the purchase contracts by cash settlement through the delivery of cash not earlier than 9:00 a.m., New York City time, on the tenth business day

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immediately preceding the stock purchase date and not later than 11:00 a.m., New York City time, on the eighth business day immediately preceding the stock purchase date, the cash payments received will automatically be applied to satisfy in full such holder s obligation to purchase shares of our common stock under the purchase contracts.

Shares of our common stock will then be issued and delivered to holders of purchase contracts or their designee, upon payment of the applicable consideration, presentation and surrender of the certificate evidencing the normal units, if the normal units are held in certificated form, and payment by a holder of any transfer or similar taxes payable in connection with the issuance of our common stock to any person other than such holder. Prior to the date on which shares of our common stock are issued in settlement of purchase contracts, shares of our common stock underlying the related purchase contracts will not be deemed to be outstanding for any purpose and holders will have no rights with respect to the common stock, including voting rights, rights to respond to tender offers and rights to receive any dividends or other distributions on the common stock, by virtue of holding the purchase contracts.

Cash will be paid in lieu of fractional shares of common stock otherwise issuable pursuant to the purchase contracts.

Remarketing

The senior notes held as part of the normal units were successfully remarketed in the second remarketing on June 28, 2005. The closing of such successful remarketing occurred on July 1, 2005. The remarketed notes were sold in a confidential private placement to qualified institutional buyers and outside the United States to persons other than U.S. persons in reliance upon Regulation S under the Securities Act. The proceeds of such successful remarketing were used to purchase a specified portfolio of U.S. treasury securities, that were then pledged as collateral to secure the obligations of the holders of the normal units under the related purchase contracts. The proceeds received on the business day immediately preceding the stock purchase date when the pledged treasury securities then held as part of the normal units mature will be used to satisfy the holders obligation to purchase shares of our common stock on the stock purchase date.

Early Settlement

At any time not later than 11:00 a.m., New York City time, on the eleventh business day immediately preceding the stock purchase date, a holder of ESUs may settle the related purchase contracts by delivering the form of Election to Settle Early to the purchase contract agent accompanied by payment in immediately available funds in an amount equal to $50 multiplied by the number of related purchase contracts being settled; *provided,* that at that time, if so required under the United States federal securities laws, there is in effect a registration statement and a current prospectus is available covering the shares of common stock to be delivered in respect of the purchase contracts being settled. If such holder delivers the properly completed and executed form of Election to Settle Early (and the related units certificate, if applicable) and payment with respect to any purchase contract during the period from the close of business on any record date next preceding any payment date to the opening of business on such payment date, such holder must also deliver an amount equal to the quarterly contract adjustment payment payable on the payment date with respect to the purchase contract.

No later than the third business day after an early settlement, we will issue, and the holder will be entitled to receive, 2.0886 shares of our common stock for each purchase contract being settled, regardless of the market price of our common stock on the date of early settlement, subject to adjustment under the circumstances described under

Anti-dilution Adjustments below. At that time, the holder s right to receive future contract adjustment payments will terminate and such holder will not receive any accumulated and unpaid contract adjustment payments or deferred contract adjustment payments. The portfolio of treasury securities underlying those ESUs will also be transferred to the holder free and clear of our security interest.

So long as the ESUs are evidenced by one or more global security certificates deposited with the securities depositary, procedures for early settlement will also be governed by standing arrangements between the securities depositary and the purchase contract agent.

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We have agreed that, if required under the United States federal securities laws, we will use commercially reasonable efforts to (1) have in effect, subject to some exceptions, a registration statement covering the shares of common stock to be delivered in respect of the purchase contracts being settled and (2) provide a prospectus in connection therewith, in each case in a form that may be used in connection with the early settlement process.

Early Settlement upon Cash Merger

Prior to the stock purchase date, if we are involved in a merger in which at least 30% of the consideration for our common stock consists of cash or cash equivalents (cash merger), each holder of ESUs will have the right to accelerate and settle the related purchase contracts on the merger early settlement date at the settlement rate in effect immediately before the cash merger. We refer to this right as the merger early settlement right.

We will provide each holder with a notice of the completion of a cash merger within five business days thereof. The notice will specify a date, which shall not be less than 20 nor more than 30 days after the date of the notice, on which the optional early settlement will occur and a date by which the merger early settlement right must be exercised. The notice will set forth, among other things, the applicable settlement rate and the amount of the cash, securities and other consideration receivable by the holder upon settlement.

To exercise the merger early settlement right, holders of ESUs must deliver to the purchase contract agent not later than 5:00 p.m., New York City time, on the business day immediately preceding the merger early settlement date:

the form of Election to Settle Early, and

payment in immediately available funds in an amount equal to $50 multiplied by the number of purchase contracts being settled; *provided,* that, to the extent the merger consideration consists of cash, we may provide in the notice of cash merger that the $50 purchase price per purchase contract will be offset against the amount of cash that will be receivable by the holder upon settlement;

provided, that, at that time, if so required under the United States federal securities laws, there is in effect a registration statement and a current prospectus is available covering the shares of common stock to be delivered in respect of the purchase contracts being settled. If such holder delivers the properly completed and executed form of Election to Settle Early (and the related ESUs certificate, if applicable) and payment with respect to any purchase contract during the period from the close of business on any record date next preceding any payment date to the opening of business on such payment date, such holder must also deliver an amount equal to the quarterly contract adjustment payment payable on the payment date with respect to the purchase contract.

If a holder exercises the merger early settlement right, we will deliver to such holder on the merger early settlement date the kind and amount of securities, cash or other property that such holder would have been entitled to receive if such holder had settled the purchase contract immediately before the cash merger at the settlement rate in effect at such time. At that time, such holder s right to receive future contract adjustment payments will terminate and such holder will not receive any accumulated and unpaid contract adjustment payments or deferred contract adjustment payments. Holders will also receive the portfolio of treasury securities underlying those units free and clear of our security interest.

If a holder does not elect to exercise its merger early settlement right, its ESUs will remain outstanding and subject to normal settlement on the stock purchase date.

So long as the ESUs are evidenced by one or more global security certificates deposited with the securities depositary, procedures for cash merger early settlement will also be governed by standing arrangements between the securities depositary and the purchase contract agent.

We have agreed that, if required under the United States federal securities laws, we will use commercially reasonable efforts to (1) have in effect, subject to some exceptions, a registration statement covering the shares of common stock to be delivered in respect of the purchase contracts being settled and

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(2) provide a prospectus in connection therewith, in each case in a form that may be used in connection with the early settlement upon a cash merger.

Anti-dilution Adjustments

To maintain a holder s relative investment in our common stock upon the occurrence of certain events, the formula for determining the settlement rate may be adjusted if those events occur, including:

(1) the payment of dividends or other distributions of our common stock on our common stock;

(2) the issuance to all holders of our common stock of rights, warrants or options (other than any dividend reinvestment or share purchase or similar plans) entitling them to subscribe for or purchase our common stock at less than the current market price (as defined below) thereof;

(3) subdivisions, splits and combinations of our common stock;

(4) distributions to all holders of our common stock of evidences of our indebtedness, shares of capital stock, securities, cash or other assets (excluding any dividend or distribution covered by clause (1) or (2) above and any dividend or distribution paid exclusively in cash);

(5) distributions consisting exclusively of cash to all holders of our common stock in an aggregate amount that, when combined with:

(a) other all-cash distributions made within the preceding 12 months; and

(b) the cash and the fair market value, as of the date of expiration of the tender or exchange offer referred to below, of the consideration paid in respect of any tender or exchange offer by us or a subsidiary of ours for our common stock concluded within the preceding 12 months;

exceeds 15% of our aggregate market capitalization (such aggregate market capitalization being the product of the current market price of our common stock multiplied by the number of shares of common stock then outstanding) on the date fixed for the determination of shareholders entitled to receive such distribution; and

(6) the successful completion of a tender or exchange offer made by us or any subsidiary of ours for our common stock that involves an aggregate consideration that, when combined with:

(a) any cash and the fair market value of other consideration payable in respect of any other tender or exchange offer by us or a subsidiary of ours for our common stock concluded within the preceding 12 months; and

(b) the aggregate amount of any all-cash distributions to all holders of our common stock made within the preceding 12 months,

exceeds 15% of our aggregate market capitalization on the date of expiration of such tender or exchange offer.

With respect to an adjustment pursuant to clause (4) where there has been a payment of a dividend or other distribution on our common stock of shares of capital stock of any class or series, or similar equity interests, of or relating to a subsidiary or other business unit, which we refer to as a spin-off, the settlement rate in effect immediately before the close of business on the record date fixed for determination of stockholders entitled to receive that distribution will be increased by multiplying the settlement rate by a fraction:

the numerator of which is the current market price of our common stock plus the fair market value, determined as described below of the portion of those shares of capital stock or similar equity interests so distributed applicable to one share of common stock; and

the denominator of which is the current market price of our common stock.

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The adjustment to the settlement rate with respect to a spin-off will occur at the earlier of:

the tenth trading day from, and including, the effective date of the spin-off; and

the date of pricing of the securities being offered in the initial public offering of the spin-off, if that initial public offering is effected simultaneously with the spin-off.

For purposes of this section, initial public offering means the first time securities of the same class or type as the securities being distributed in the spin-off are bona fide offered to the public for cash.

If a spin-off is not effected simultaneously with an initial public offering of the securities being distributed in the spin-off, the fair market value of the securities to be distributed to holders of our common stock means the average of the sale prices of those securities over the first 10 trading days after the effective date of the spin-off. Also, for purposes of such a spin-off, the current market price of our common stock means the average of the sales prices of our common stock over the first 10 trading days after the effective date of the spin-off. If, however, an initial public offering of the securities being distributed in the spin-off is to be effected simultaneously with the spin-off, the fair market value of the securities being distributed in the spin-off means the initial public offering price, while the current market price our common stock means the sale price of our common stock on the trading day on which the initial public offering price of the securities being distributed in the spin-off is determined.

In the case of certain reclassifications, consolidations, mergers, sales or transfers of assets or other reorganization transactions pursuant to which our common stock is converted into the right to receive other securities, cash or property, each purchase contract then outstanding would, without the consent of the holders of the related ESUs, become a contract to purchase such other securities, cash or property (instead of shares of our common stock). The formula for determining the settlement rate will be adjusted accordingly at the time of the reorganization event to reflect the other securities, cash or property the holders of our common stock received in the reorganization event. On the stock purchase date, the adjusted settlement rate will be applied to determine what a holder of an ESU will receive in settlement of the purchase contract. Holders have the right to settle their obligations under the purchase contracts early in the event of certain cash mergers, as described under Early Settlement upon Cash Merger.

If at any time we make a distribution of property to our stockholders which would be taxable to stockholders as a dividend for U.S. federal income tax purposes (for example, distributions of evidences of indebtedness or assets, but generally not stock dividends or rights to subscribe for capital stock) and, pursuant to the settlement rate adjustment provisions of the purchase contract agreement, the settlement rate is increased, such increase may give rise to a taxable dividend to holders of ESUs.

In addition, we may increase the settlement rate if our board of directors deems it advisable, to avoid or diminish any income tax to holders of our common stock resulting from any dividend or distribution of common stock (or rights to acquire common stock) or from any event treated as a dividend or distribution for income tax purposes, or for any other reasons.

Adjustments to the settlement rate will be calculated to the nearest 1/10,000th of a share. No adjustment in the settlement rate will be required unless the adjustment would require an increase or decrease of at least 1% in the settlement rate. If any adjustment is not required to be made because it would not change the settlement rate by at least 1%, then the adjustment will be carried forward and taken into account in any subsequent adjustment.

We are required, within ten business days following an adjustment in the settlement rate, to provide written notice to the purchase contract agent and the holders of ESUs of the adjustment. We will also be required to deliver a statement setting forth in reasonable detail the method by which the adjustment to the settlement rate was determined and setting forth the revised settlement rate.

Each adjustment to the settlement rate will result in a corresponding adjustment to the number of shares of our common stock issuable upon early settlement of a purchase contract.

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If an adjustment is made to the settlement rate as a result of an event described in clauses (1) through (6) above, an adjustment will also be made to the applicable market value solely to determine which of the three clauses in the definition of settlement rate will be applicable on the stock purchase date.

Pledged Securities and Pledge Agreement

The specified portfolio of treasury securities was pledged to the collateral agent for our benefit. Under the pledge agreement, the pledged securities will secure the holders obligations to purchase shares of our common stock under the related purchase contracts. Holders cannot separate or separately transfer the purchase contracts from the pledged securities held as part of the ESUs. A holder s rights to the pledged securities are subject to our security interest created by the pledge agreement. Holders are not permitted to withdraw the pledged securities related to the ESUs from the pledge arrangement except for specified purposes or upon the occurrence of specified events.

Subject to our security interest and the terms of the purchase contract and the pledge agreements each holder of normal units will retain ownership of the specified portfolio of treasury securities.

We have no interest in the pledged securities other than our security interest.

Termination of Purchase Contracts

The purchase contracts, our related rights and obligations and those of the holders of the ESUs, including their rights to receive accumulated and unpaid contract adjustment payments or deferred contract adjustment payments and obligations to purchase shares of our common stock, will automatically terminate upon the occurrence of particular events of our bankruptcy, insolvency or reorganization.

Upon such a termination of the purchase contracts, the collateral agent will release the securities held by it to the purchase contract agent for distribution to the holders. If a holder would otherwise have been entitled to receive less than $1,000 principal amount at maturity of any treasury security upon termination of the purchase contract, the purchase contract agent will dispose of the security for cash and pay the cash to the holder. Upon termination, however, the release and distribution may be subject to a delay. If we become the subject of a case under the U.S. Bankruptcy Code, a delay in the release of the pledged senior notes or treasury securities may occur as a result of the automatic stay under the U.S. Bankruptcy Code and continue until the automatic stay has been lifted. The automatic stay will not be lifted until such time as the bankruptcy judge agrees to lift it and return the collateral to the holders.

The Purchase Contract Agreement

Distributions on the ESUs will be payable, purchase contracts will be settled and transfers of the ESUs will be registrable at the office of the purchase contract agent in the Borough of Manhattan, the City of New York. In addition, if the ESUs do not remain in book-entry form, payment of distributions on the ESUs may be made, at our option, by check mailed to the address of the persons shown on the ESUs registers.

If any quarterly payment date or the stock purchase date is not a business day, then any payment required to be made on that date must be made on the next business day (and so long as the payment is made on the next business day, without any interest or other payment on account of any such delay), except that if the next business day is in the next calendar year, the payment or settlement will be made on the prior business day with the same force and effect as if made on the payment date.

If a holder s ESUs are held in certificated form and such holder fails to surrender the certificate evidencing its ESUs to the purchase contract agent on the stock purchase date, the shares of our common stock issuable in settlement of the related purchase contracts will be registered in the name of the purchase contract agent. These shares, together with any distributions on them, will be held by the purchase contract agent as agent for the holder s benefit, until the certificate is presented and surrendered or the holder provides satisfactory evidence that the certificate has been destroyed, lost or stolen, together with any indemnity that may be required by the purchase contract agent and us.

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If a holder s ESUs are held in certificated form and:

the purchase contracts have terminated prior to the stock purchase date;

the related pledged securities have been transferred to the purchase contract agent for distribution to the holders; and

the holder fails to surrender the certificate evidencing its ESUs to the purchase contract agent,

the pledged securities that would otherwise be delivered to the holder and any related payments will be held by the purchase contract agent as agent for such holder s benefit, until the holder presents and surrenders the certificate or provides the evidence and indemnity described above.

The purchase contract agent will not be required to invest or to pay interest on any amounts held by it pending distribution.

No service charge will be made for any registration of transfer or exchange of the ESUs, except for any applicable tax or other governmental charge.

Modification

The purchase contract agreement, the pledge agreement and the purchase contracts may be amended with the consent of the holders of a majority of the ESUs at the time outstanding. However, no fundamental modification may be made without the consent of the holder of each outstanding ESU affected by the modification (in addition to the consent of the holders of at least a majority of the ESUs at the time outstanding).

Consolidation, Merger, Sale or Conveyance

We have agreed in the purchase contract agreement that we will not (1) merge with or into or consolidate with any other entity or (2) sell, assign, transfer, lease or convey all or substantially all of our properties and assets to any person, firm or corporation other than, with respect to clause (2), our direct or indirect wholly owned subsidiaries, unless:

we are the continuing corporation or the successor corporation is a corporation organized under the laws of the United States of America or any state or the District of Columbia;

the successor entity expressly assumes our obligations under the purchase contract agreement, the pledge agreement, the ESUs, the senior notes and the remarketing agreement; and

we or such corporation is not, immediately after such merger, consolidation, sale, assignment, transfer, lease or conveyance, in default in the performance of any of our or its obligations under the purchase contract agreement, the pledge agreement, the ESUs, the senior notes or the remarketing agreement.

Governing Law

The ESUs, the purchase contract agreement, the pledge agreement, the remarketing agreement, the senior indenture and the senior notes are governed by, and construed in accordance with, the laws of the State of New York.

Information Concerning the Purchase Contract Agent

HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank) acts as purchase contract agent. The purchase contract agent acts as the agent and attorney-in-fact for the holders of ESUs from time to time.

Information Concerning the Collateral Agent

The Bank of New York Trust Company, N.A. acts as collateral agent. The collateral agent acts solely as our agent and will not assume any obligation or relationship of agency or trust for or with any of the holders of

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ESUs except for the obligations owed by a pledgee of property to the owner thereof under the pledge agreement and applicable law.

The pledge agreement also provides for The Bank of New York Trust Company, N.A. to act as custodial agent with respect to senior notes that are held separately and participating in a remarketing.

Common Stock Transfer Agent and Registrar

The transfer agent and registrar for our common stock is EquiServe Trust Company, N.A.

Fees and Expenses

The purchase contract agreement provides that we will pay all fees and expenses related to:

the offering of the normal units;

the retention of the collateral agent and the purchase contract agent;

the enforcement by the purchase contract agent of the rights of the holders of ESUs; and

with certain exceptions, stock transfer and similar taxes attributable to the initial issuance and delivery of our common stock upon settlement of the purchase contracts.

Book-Entry System

DTC acts as securities depositary for the ESUs. The ESUs have been issued only as fully-registered securities registered in the name of Cede & Co., DTC s nominee. One or more fully-registered global security certificates, representing the total aggregate number of normal units or stripped units, has been issued and deposited with DTC and bears a legend regarding the restrictions on exchanges and registration of transfer referred to below.

LEGAL MATTERS

The validity of our common stock offered hereby will be passed upon by Andrews Kurth LLP, Houston, Texas.

EXPERTS

The consolidated financial statements of El Paso as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004 and management s assessment of the effectiveness of internal control over financial reporting (which is included in Management s Report on Internal Control over Financial Reporting) as of December 31, 2004 included in this Prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to the Company s restatements of its financial statements as described in Note 1 to the financial statements and an adverse opinion on the effectiveness of internal control over financial reporting), of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

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The consolidated financial statements of Midland Cogeneration Venture Limited Partnership as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004 and management s assessment of the effectiveness of internal control over financial reporting (which is included in Management s Report on Internal Control over Financial Reporting) as of December 31, 2004 included in this Prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

Information included in this prospectus related to the estimated reserves attributable to certain of our oil and natural gas properties was prepared by Ryder Scott Company, L.P., an independent petroleum engineering firm. The report of Ryder Scott Company for our reserves as of December 31, 2004 is referenced herein in reliance upon the authority of said firm as experts with respect to the matters covered by their report and the giving of their report.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)
(Unaudited)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Operating revenues	$ 1,224	$ 1,524	$ 2,366	$ 3,081
Operating expenses				
Cost of products and services	60	435	159	825
Operation and maintenance	438	373	880	774
Depreciation, depletion and amortization	294	263	574	538
Loss on long-lived assets	360	17	381	255
Taxes, other than income taxes	65	66	136	130
	1,217	1,154	2,130	2,522
Operating income (loss)	7	370	236	559
Earnings (loss) from unconsolidated affiliates	(19)	98	171	185
Other income, net	71	30	104	74
Interest and debt expense	(340)	(410)	(690)	(833)
Distributions on preferred interests of consolidated subsidiaries	(3)	(6)	(9)	(12)
Income (loss) before income taxes	(284)	82	(188)	(27)
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)
Preferred stock dividends	(8)		(8)	
Net income (loss) available to common stockholders	$ (246)	$ 5	$ (140)	$ (191)
Basic and diluted income (loss) per common share				
Income (loss) from continuing operations	$ (0.37)	$ 0.05	$ (0.22)	$ (0.13)
Discontinued operations, net of income taxes	(0.01)	(0.04)		(0.17)
Net income (loss) per common share	$ (0.38)	$ 0.01	$ (0.22)	$ (0.30)
Basic and diluted average common shares outstanding	641	639	640	639
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)
(Unaudited)

	June 30, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,540	$ 2,117
Accounts and notes receivable		
Customers, net of allowance of $77 in 2005 and $199 in 2004	975	1,388
Affiliates	90	133
Other	151	188
Assets from price risk management activities	576	601
Margin and other deposits held by others	328	79
Deferred income taxes	607	418
Other	539	708
Total current assets	4,806	5,632
Property, plant and equipment, at cost		
Pipelines	19,609	19,418
Natural gas and oil properties, at full cost	15,693	14,968
Power facilities	957	1,550
Gathering and processing systems	64	171
Other	629	882
	36,952	36,989
Less accumulated depreciation, depletion and amortization	18,265	18,177
Total property, plant and equipment, net	18,687	18,812
Other assets		
Investments in unconsolidated affiliates	2,275	2,614
Assets from price risk management activities	1,203	1,584
Goodwill and other intangible assets, net	422	428
Other	2,283	2,313
	6,183	6,939
Total assets	$ 29,676	$ 31,383

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)
(In millions, except share amounts)
(Unaudited)

	June 30, 2005	December 31, 2004
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 792	$ 1,052
Affiliates	8	21
Other	399	483
Short-term financing obligations, including current maturities	1,099	955
Liabilities from price risk management activities	920	852
Margin and other deposits	342	131
Western Energy Settlement		44
Accrued interest	281	333
Other	818	701
Total current liabilities	4,659	4,572
Long-term financing obligations, less current maturities	16,379	18,241
Other		
Liabilities from price risk management activities	1,390	1,026
Deferred income taxes	1,528	1,312
Western Energy Settlement		351
Other	1,861	2,076
	4,779	4,765
Commitments and contingencies		
Securities of subsidiaries	59	367
Stockholders equity		
4.99% Convertible perpetual preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares in 2005; stated at liquidation value	750	
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 653,065,090 shares in 2005 and 651,064,508 shares in 2004	1,959	1,953
Additional paid-in capital	4,431	4,538
Accumulated deficit	(2,941)	(2,809)
Accumulated other comprehensive income (loss)	(183)	1
Treasury stock (at cost); 7,361,325 shares in 2005 and 7,767,088 shares in 2004	(189)	(225)
Unamortized compensation	(27)	(20)

Total stockholders equity	3,800	3,438
Total liabilities and stockholders equity	$ 29,676	$ 31,383

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Six Months Ended June 30,	
	2005	**2004**
Cash flows from operating activities		
Net loss	$ (132)	$ (191)
Less loss from discontinued operations, net of income taxes	(1)	(106)
Net loss from continuing operations	(131)	(85)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	574	538
Loss on long-lived assets	381	255
Earnings from unconsolidated affiliates, adjusted for cash distributions	(24)	(27)
Deferred income taxes	4	37
Other non-cash items	35	53
Other asset and liability changes	(812)	(636)
Cash provided by continuing operations	27	135
Cash provided by (used in) discontinued operations	(17)	161
Net cash provided by operating activities	10	296
Cash flows from investing activities		
Additions to property, plant and equipment	(806)	(782)
Purchases of interests in equity investments	(15)	(21)
Net proceeds from the sale of assets and investments	834	165
Proceeds from settlement of a foreign currency derivative	131	
Cash paid for acquisitions, net of cash acquired	(178)	2
Net change in restricted cash	62	447
Net change in notes receivable from unconsolidated affiliates	5	98
Other	47	
Cash provided by (used in) continuing operations	80	(91)
Cash provided by discontinued operations	70	1,113
Net cash provided by investing activities	150	1,022
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,563)	(1,024)
Net proceeds from the issuance of long-term debt and other financing obligations	458	50
Net proceeds from the issuance of preferred stock	723	
Redemption of preferred stock of subsidiary	(300)	

Dividends paid	(51)	(49)
Contributions from discontinued operations	53	909
Issuances of common stock, net		73
Other	(4)	(21)
Cash used in continuing operations	(684)	(62)
Cash used in discontinued operations	(53)	(1,274)
Net cash used in financing activities	(737)	(1,336)
Change in cash and cash equivalents	(577)	(18)
Cash and cash equivalents		
Beginning of period	2,117	1,429
End of period	$ 1,540	$ 1,411

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net income (loss)	$ (238)	$ 5	$ (132)	$ (191)
Foreign currency translation adjustments (net of income taxes of $6 and $7 in 2005 and $14 and $51 in 2004)	(4)	(24)	7	(20)
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $13 and $89 in 2005 and $2 and $12 in 2004)	17	(4)	(172)	(23)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 and $12 in 2005 and $7 and $15 in 2004)	2	24	(19)	39
Other comprehensive income (loss)	15	(4)	(184)	(4)
Comprehensive income (loss)	$ (223)	$ 1	$ (316)	$ (195)

See accompanying notes.

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EL PASO CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared the accompanying condensed consolidated financial statements and related notes under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read this these consolidated interim financial statements along with our 2004 consolidated financial statements, included herein, beginning on page F-37, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2005, and for the quarters and six months ended June 30, 2005 and 2004, are unaudited. We derived the balance sheet as of December 31, 2004, from the audited balance sheet included herein, beginning on page F-38. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of the results of operations for the entire year. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. 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 were not material to prior period results or historical trends. Additionally, our financial statements for prior periods include reclassifications to conform to the current period presentation. These reclassifications had no effect on our previously reported net income (loss) or stockholders equity.

Significant Accounting Policies

Our significant accounting policies are discussed in our 2004 Annual Report on Form 10-K, as amended. The information below provides updating information, disclosure where these policies have changed or required interim disclosures with respect to those policies.

Variable Interest Entities

In 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which we adopted on January 1, 2004. This interpretation defined a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity s losses or income, including fees paid by the entity.

In conjunction with our application of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity s two 274 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $27 million to $32 million per year related to its power plants. The following is a summary of the financial statement impacts of our transactions

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with this entity for the six months ended June 30, 2005 and 2004 and as of June 30, 2005 and December 31, 2004:

	2005	2004
	(In millions)	
Operating revenues	$ (111)	$ (3)
Current liabilities from price risk management activities	21	20
Non-current liabilities from price risk management activities	127	29

As of December 31, 2004, our financial statements included two consolidated entities that own a 238 MW power facility and a 158 MW power facility in Manaus, Brazil. In January 2005, these entities entered into agreements with Manaus Energia, under which Manaus Energia will supply substantially all of the fuel consumed and will purchase all of the power generated by the projects through January 2008, at which time Manaus Energia will assume ownership of the plants. We deconsolidated these two entities in January 2005 because Manaus Energia will absorb a majority of the potential losses of the entities under the new agreements and will assume ownership of the plants at the end of the agreements. The impact of this deconsolidation was an increase in investments in unconsolidated affiliates of $103 million, a decrease in property, plant and equipment of $74 million, a decrease in other assets of $32 million and a decrease in other liabilities of $3 million.

Stock-Based Compensation

We account for our stock-based compensation plans using the intrinsic value method under the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. Had we accounted for our stock option grants using Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the loss and per share impacts of stock-based compensation on our financial statements would have been different. The following table shows the impact on net income (loss) and income (loss) per share had we applied SFAS No. 123:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Net income (loss) available to common stockholders as reported	$ (246)	$ 5	$ (140)	$ (191)
Add: Stock-based compensation expense in net income (loss), net of taxes	3	7	5	11
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	5	11	10	21
Net income (loss) available to common stockholders, pro forma	$ (248)	$ 1	$ (145)	$ (201)
Income (loss) per share:				
Basic and diluted, as reported	$ (0.38)	$ 0.01	$ (0.22)	$ (0.30)
Basic and diluted, pro forma	$ (0.39)	$	$ (0.23)	$ (0.31)

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2005, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95.* This standard requires that companies measure and record the fair value of their stock based compensation awards at fair value on the date they are granted to employees. This fair value is determined using a variety of assumptions, including those related to

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volatility rates, forfeiture rates and the option pricing model used (e.g. binomial or Black Scholes). These assumptions could differ from those we have utilized in determining our proforma compensation expense (indicated above). This standard will also impact the manner in which we recognize the income tax impacts of our stock compensation programs in our financial statements. This standard is required to be adopted beginning January 1, 2006. Upon adoption, we will apply the standard prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We are currently evaluating the impact of this adoption on our consolidated financial statements.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. 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 have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Asset Retirement Obligations. In March 2005, the FASB Issued FIN Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing and/or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, *Accounting for Asset Retirement Obligations*, which we adopted on January 1, 2003. FIN No. 47 will require us to accrue a liability when a range of scenarios indicates that the potential timing and/or settlement amounts of our conditional asset retirement obligations can be determined. We will adopt the provisions of this standard in the fourth quarter of 2005 and have not yet determined the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Pipeline Integrity Costs. In June 2005, the Federal Energy Regulatory Commission (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.

2. Acquisitions

In July 2005, we announced that our subsidiary, El Paso Production Holding Company (EPPH), will acquire Medicine Bow Energy Corporation for $814 million in cash. This transaction is expected to close during the third quarter of 2005.

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3. Divestitures

Sales of Assets and Investments

During the six months ended June 30, 2005 and 2004, we completed the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	2005	2004
	(In millions)	
Regulated		
Pipelines	$ 35	$ 50
Non-regulated		
Power	176	99
Field Services	501	
Other		
Corporate	121	16
Total continuing	833[1]	165
Discontinued	85	1,261
Total	$ 918	$ 1,426

(1) Proceeds exclude returns of capital from unconsolidated affiliates and cash transferred with the assets sold and include costs incurred for disposal. These increased our sales proceeds by $1 million for the six months ended June 30, 2005.

The following table summarizes the significant assets sold during the six months ended June 30:

	2005	2004
Pipelines	Facilities located in the southeastern U.S.	Australia pipeline Aircraft
Power	Cedar Brakes I and II Interest in a power plant in India Interest in a power plant in England 4 domestic power facilities Power turbine	Mohawk River Funding IV Utility Contract Funding (UCF) Bastrop Company equity investment
Field Services	9.9% interest in general partner of Enterprise Products Partners, L.P. 13.5 million common units in Enterprise Interest in Indian Springs natural gas gathering system and processing facility	None
Corporate	Lakeside Technology Center	Aircraft
Discontinued		

Interest in Paraxylene facility	Natural gas and oil production properties in Canada
MTBE processing facility	Aruba and Eagle Point refineries and other petroleum assets
International natural gas and oil production properties	

In the third quarter of 2005, we also completed the sale of our 50 percent interest in the Korean Independent Energy Corporation power facility. We will record the receipt of $284 million in proceeds and a $109 million gain in the third quarter of 2005 related to this sale in our Power segment. Additionally, in the second and third quarters of 2005, we announced the sales of substantially all of our other Asia power assets. We expect to receive total proceeds of approximately $180 million for these assets.

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Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. As of June 30, 2005, we had assets held for sale of $5 million related to two Asian power plants and a domestic power asset, which was fully impaired in previous years. We expect to sell these assets within the next twelve months. As of December 31, 2004, we had assets held for sale of $75 million related to our Indian Springs natural gas gathering system and processing facility which was sold in the first quarter of 2005 and certain domestic power assets.

Discontinued Operations

South Louisiana Gathering and Processing Operations. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. This sale is expected to be completed by the end of 2005.

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we had completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. We completed the sale of substantially all of our remaining properties in 2005 for total proceeds of approximately $6 million.

Petroleum Markets. During 2003, our Board of Directors approved the sales of our petroleum markets businesses and operations. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million.

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The petroleum markets, other international natural gas and oil production operations, and south Louisiana gathering and processing operations discussed above are classified as discontinued operations in our financial statements. As of June 30, 2005 and December 31, 2004, the total assets of our discontinued operations were $193 million and $106 million, and our total liabilities were $121 million and $12 million. These amounts are classified in other current assets and liabilities. The assets and liabilities of our south Louisiana gathering and processing operations as of December 31, 2004, and the results of its operations for periods prior to January 1, 2005, were not reclassified to discontinued operations, as these operations were not material to prior period results or historical trends. The summarized operating results of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Operating Results Data				
Quarter Ended June 30, 2005				
Revenues	$ 30	$	$ 90	$ 120
Costs and expenses	(33)	(1)	(79)	(113)
Loss on long-lived assets		(4)		(4)
Other expense	(4)			(4)
Income (loss) before income taxes	(7)	(5)	11	(1)
Income taxes	1	(2)	5	4
Income (loss) from discontinued operations, net of income taxes	$ (8)	$ (3)	6	$ (5)
Quarter Ended June 30, 2004				
Revenues	$ 54	$ 1	$	$ 55
Costs and expenses	(77)	(3)		(80)
Gain on long-lived assets	4			4
Other income	2			2
Loss before income taxes	(17)	(2)		(19)
Income taxes	(3)	13		10
Loss from discontinued operations, net of income taxes	$ (14)	$ (15)	$	$ (29)
Six Months Ended June 30, 2005				
Revenues	$ 74	$ 2	$ 177	$ 253
Costs and expenses	(86)	(2)	(157)	(245)
Gain (loss) on long-lived assets	3	(5)		(2)
Other income	11			11

Income (loss) before income taxes	2	(5)	20	17
Income taxes	13	(3)	8	18
Income (loss) from discontinued operations, net of income taxes	$ (11)	$ (2)	12	$ (1)

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	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Six Months Ended June 30, 2004				
Revenues	$ 693	$ 28	$	$ 721
Costs and expenses	(730)	(47)		(777)
Loss on long-lived assets	(38)	(16)		(54)
Interest and debt expense	(3)	1		(2)
Other expense	(8)			(8)
Loss before income taxes	(86)	(34)		(120)
Income taxes	(9)	(5)		(14)
Loss from discontinued operations, net of income taxes	$ (77)	$ (29)	$	$ (106)

4. Restructuring Costs

During 2004 and 2005, we incurred organizational restructuring costs included in our operation and maintenance expenses as part of our ongoing liquidity enhancement and cost reduction efforts. The discussion below provides additional details of these costs.

Office relocation and consolidation. As of December 31, 2004, we had a liability related to our remaining lease obligations associated with the consolidation of our Houston based operations. This liability was discounted, net of estimated sub-lease 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. In June 2005, we signed a termination agreement releasing us from this lease obligation, which resulted in an additional charge of $10 million. As of June 30, 2005, our total liability was $114 million.

Employee severance, retention, and transition costs. During the six months ended June 30, 2004, we incurred $33 million of employee severance costs, which included severance payments and costs for pension benefits settled under existing benefit plans. During this period, we eliminated approximately 350 full-time positions from our continuing business and approximately 1,100 positions related to businesses we discontinued. During the six months ended June 30, 2005, severance costs were not significant. Substantially all of our employee severance costs have been paid as of June 30, 2005.

5. Loss on Long-Lived Assets

Our loss on long-lived assets consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets. During each of the periods ended June 30, our loss on long-lived assets was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004

		(In millions)		
Net realized gain	$ (6)	$ (6)	$ (13)	$ (14)
Asset impairments	366	23	394	269
Loss on long-lived assets	360	17	381	255
(Gain) loss on investments in unconsolidated affiliates [1]	87	18	(32)	42
Loss on long-lived assets and investments	$ 447	$ 35	$ 349	$ 297

[1] See Note 14 on page F-32 for a further description of these gains and losses.

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Net Realized Gain

Our 2005 net realized gains are primarily related to a $9 million gain on the sale of facilities located in the southeastern United States in our Pipelines segment. Also, during the second quarter of 2005, our corporate operations recorded a $5 million gain on the sale of our Lakeside Technology Center, which was previously impaired in 2003. Our 2004 net realized gains are primarily related to a gain on aircraft sales associated with our corporate activities.

Asset Impairments

In 2005, our Power segment recorded approximately $388 million of asset impairments. During the quarter ended June 30, 2005, we recorded a $276 million impairment of our long-lived assets associated with the Macae power project in Brazil as a result of ongoing negotiations with Petrobras related to the plant. See Note 10 for a further discussion of these matters. Our Power segment also recorded impairments of $14 million during the first quarter of 2005 and $83 million during the second quarter of 2005 related to our Asian and Central American assets based on additional information received about the value we may receive upon the sale of these assets. Finally, in the first quarter of 2005, we recorded a $15 million impairment of our power turbines based on further information we received about their fair value.

Our 2004 asset impairments primarily occurred in our Power segment, including a $151 million impairment during the first quarter of 2004 related to our Manaus and Rio Negro power plants in Brazil based on the status of our negotiations to extend the power contracts at these plants, which was negatively impacted by changes in the Brazilian political environment. In addition, our Power segment recorded a $98 million impairment charge during the first quarter of 2004 related to the sale of our subsidiary, Utility Contract Funding, which owned a restructured power contract, and $10 million of impairments in the second quarter of 2004 on our domestic power plants to adjust the carrying value of these plants to their expected sales price. Finally, our Field Services segment recorded $7 million of impairments in the second quarter of 2004, primarily related to the abandonment of miscellaneous assets.

6. Income Taxes

Income taxes included in our income (loss) from continuing operations for the periods ended June 30 were as follows:

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

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs. During 2005, our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to:

Impairments of certain foreign investments for which there was only a partial corresponding income tax benefit, as well as foreign income taxed at different rates;

Benefits recorded on book versus tax differences related to certain of our Asian and Indian power assets as further described below;

A reduction of our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 Coastal Corporation income tax returns of $33 million, expiration of a tax indemnity claim, and approval of a 1986 refund claim; and

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Other items including (i) state income taxes (including valuation allowances) and state tax adjustments to reflect income tax returns as filed, net of federal income tax effects; (ii) earnings/losses from unconsolidated affiliates where we anticipate receiving dividends; and (iii) non-deductible dividends on the preferred stock of subsidiaries.

We have not historically recorded U.S. deferred tax assets or liabilities on book versus tax basis differences for a substantial portion of our international investments based on our intent to indefinitely reinvest earnings from these investments outside the U.S. However, based on current sales negotiations on certain of our Asian power assets, we currently expect to receive these sales proceeds within the U.S. During the six months ended June 30, 2005, our effective tax rate was impacted upon recording net deferred tax assets on book versus tax basis differences in these investments based on the status of these negotiations. We also recorded deferred tax benefits on the sale of an Indian power asset. As of June 30, 2005, and December 31, 2004, we have deferred tax assets of $97 million and $6 million and deferred tax liabilities of $39 million in both periods related to these investments.

In 2004, our overall effective tax rate on continuing operations was impacted by impairments of certain of our foreign investments for which there was either a partial or no corresponding tax benefit. Additionally, for the six month period ended June 30, 2004, income tax expense in a period in which there was a pre-tax loss resulted in a negative effective tax rate.

7. Earnings Per Share

We have excluded 73 million and 16 million of potentially dilutive securities for the quarters and six months ended June 30, 2005 and 2004, from the determination of diluted earnings per share (as well as their related income statement impacts) due to their antidilutive effect on income (loss) per common share. The excluded securities included convertible preferred stock and restricted stock in 2005 and stock options, trust preferred securities and convertible debentures in 2005 and 2004.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of June 30, 2005 and December 31, 2004. In the table, derivatives designated as hedges primarily consist of instruments used to hedge our natural gas and oil 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. Interest rate and foreign currency hedging derivatives consist of instruments to hedge our interest rate and currency risks on long-term debt.

	June 30, 2005	December 31, 2004
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (640)	$ (536)
Derivatives from power contract restructuring activities [1]	60	665
Other commodity-based derivative contracts[1]	36	(61)
Total commodity-based derivatives	(544)	68
Interest rate and foreign currency hedging derivatives [2]	13	239
Net assets (liabilities) from price risk management activities[3]	$ (531)	$ 307

[1] Derivatives from power contract restructuring activities as of December 31, 2004 includes $596 million of derivative contracts sold in connection with the sale of Cedar Brakes I and II in March 2005. In connection with this sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of

$240 million as of December 31, 2004.

(2) In March 2005, we repurchased approximately 528 million of debt, of which 375 million was hedged with interest rate and foreign currency derivatives. As a result of the repurchase, we removed the hedging designation on these derivatives and cancelled

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substantially all of the contracts. We recorded a gain of approximately $2 million during the first quarter of 2005 upon the reversal of the related accumulated other comprehensive income associated with these derivatives.

(3) Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivative contracts. Prior to April 2005, we used commodity prices from market-based sources such as the New York Mercantile Exchange for forward pricing data within two years. For forecasted settlement prices beyond two years, we used a combination of commodity pricing data from market-based sources and other independent pricing sources to develop price curves. These curves were then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discounted these estimated settlement values using a LIBOR curve for the majority of our derivative contracts or by using an adjusted risk free rate for our restructured power contracts.

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.

9. Debt, Other Financing Obligations and Other Credit Facilities

We had the following long-term and short-term borrowings and other financing obligations:

	June 30, 2005	December 31, 2004
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,099(1)	$ 955
Long-term financing obligations	16,379	18,241
Total	$ 17,478	$ 19,196

(1) Includes $599 million of zero coupon debentures that the holders may require us to redeem in February 2006, prior to their stated maturities.

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Long-Term Financing Obligations

From January 1, 2005 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value	Cash Received/ Paid
			(In millions)	
Issuances				
Colorado Interstate Gas Company (CIG)	Senior Notes due 2015	5.95%	$ 200	$ 197
Cheyenne Plains Gas Pipeline Company[1]	Non-recourse term loan due 2015	Variable	266	261
	Increases through June 30, 2005		$ 466	$ 458
Repayments, repurchases, retirements and other				
El Paso	Zero coupon debenture[2]		$ 236	$ 237
El Paso	Notes	6.88%	167	167
Cedar Brakes I[3]	Non-recourse notes	8.5%	241	15
Cedar Brakes II[3]	Non-recourse notes	9.88%	334	14
El Paso[4]	Euro notes	5.75%	695	722
CIG	Debentures	10.00%	180	180
Other	Long-term debt	Various	331	228
	Decreases through June 30, 2005		$ 2,184	$ 1,563
Other	Long-term debt		5	5
	Decreases through filing date		$ 2,189	$ 1,568

(1) In addition to the borrowing, we have an associated letter of credit facility for $12 million, under which we issued $6 million of letters of credit in May 2005. We also concurrently entered into swaps to convert the variable interest rate on approximately $213 million of this debt to a current fixed rate of 5.94 percent.

(2) This security has a yield-to-maturity of approximately four percent.

(3) Prior to the sale of Cedar Brakes I and II, we made $29 million of scheduled principal repayments. Upon the sale of these entities in March 2005, the remaining balance of the debt was eliminated.

(4) We recorded a $26 million loss on the early extinguishment of this debt.

On July 1, 2005, we remarketed our $272 million, 6.14% Senior Notes that were due August 16, 2007. The remarketed notes bear interest at 7.625% and are due August 16, 2007. The proceeds from the offering are being held by a collateral agent in connection with our 9.0% equity security units. For a further discussion of our equity security units, Notes to Consolidated Financial Statements, Note 15, on page F-79. The equity security unit holders are

obligated to fulfill their commitment to purchase approximately 13.6 million shares of our common stock on August 16, 2005. At that time, we will issue the common stock and will receive approximately $272 million in cash.

We recorded accretion expense on our zero coupon bonds of $6 million and $9 million during the second quarter of 2005 and 2004, and $13 million and $18 million during the six months ended June 30, 2005 and 2004. These amounts are added to the principal balance each period and are included in our long term debt. We account for redemption of zero coupon debentures as a financing activity in our statement of cash flows, which included this accretion. During the six months ended June 30, 2005 we redeemed $236 million of our zero coupon debentures of which $34 million represented increased principal due to the accretion of interest on the debentures.

Credit Facilities

As of June 30, 2005, we had borrowing capacity under our $3 billion credit agreement of $0.4 billion. Amounts outstanding under the credit agreement were a $1.2 billion term loan and $1.4 billion of letters of

credit. For a further discussion of our $3 billion credit agreement, our other credit facilities and their related restrictive covenants, see Notes to Consolidated Financial Statements, Note 15, on page F-79.

The availability of borrowings under our $3 billion credit agreement and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. There have been no substantial changes to our restrictive covenants from those described in our Annual Report of Form 10-K, as amended. However, El Paso CGP Company is no longer required to maintain a minimum net worth of $850 million due to the repayment of the debt covered by the indenture.

Letters of Credit

As of June 30, 2005, we had outstanding letters of credit of approximately $1.5 billion, of which $1.4 billion was outstanding under our $3 billion credit agreement and $102 million was supported with cash collateral. Included in our outstanding letters of credit were approximately $1.0 billion of letters of credit securing our recorded obligations related to price risk management activities.

10. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2003, we entered into various agreements to resolve the principal litigation, investigations, claims, and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western United States (the Western Energy Settlement). In April 2005, we paid the remaining $442 million due under a 20 year cash payment obligation that arose under certain of these agreements and recorded an additional $59 million charge in the first quarter of 2005 resulting from this prepayment. These agreements also included a Joint Settlement Agreement or JSA where we agreed to certain conditions regarding service and facilities on El Paso Natural Gas Company (EPNG). In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA with the Federal Energy Regulatory Commission (FERC). In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC s ruling to the U.S. Court of Appeals for the District of Columbia, where this matter is pending. This appeal has been fully briefed but has not yet been set for oral argument.

Shareholder/ Derivative/ ERISA Litigation

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. This consolidated lawsuit, which alleges violations of federal securities laws against us and several of our current and former officers and directors, includes allegations regarding the accuracy or completeness of press releases and other public statements made during the class period from 2001 through early 2004 related to wash trades, mark-to-market accounting, off-balance sheet debt, the overstatement of oil and gas reserves and manipulation of the California energy market. Discovery in the consolidated lawsuit is currently stayed.

Derivative Litigation. Since 2002, six shareholder derivative actions have also been filed. Three of the actions allege the same claims as in the consolidated shareholder class action suit described above, with one of the actions including a claim for compensation disgorgement against certain individuals. Discovery in two of those three lawsuits are stayed in federal court in Houston, Texas. The third, originally pending in Delaware, was voluntarily dismissed by the plaintiffs in July 2005. The Delaware plaintiffs claims will be pursued with two other actions consolidated in state court in Houston, Texas. The state court lawsuits generally allege that the manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value and are set for trial in January 2006. The sixth derivative action, *Laties v. El Paso, et al.* was filed in Delaware in April 2005 against our former Chief Executive Officer, William Wise and current and former members of our Board of Directors. This derivative action seeks restitution of the 2001 incentive compensation paid to William Wise due to the Company s restatement of its financial statements for that year.

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ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. Discovery in this lawsuit is currently stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits. There are certain deductibles and co-pay obligations under some of those insurance coverages for which we have established certain accruals we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Company and Case Corporation.* The suit alleges, among other things, that El Paso and Case violated ERISA, and that they should be required to pay all amounts above the cap. Although such amounts will vary over time, the amounts above the cap have recently been approximately $1.8 million per month. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend, and hold Case harmless for the amounts it would be required to pay. In February 2004, a judge ruled that Case would be required to pay the amounts incurred above the cap. Furthermore, in September 2004, a judge ruled that pending resolution of this matter, El Paso must indemnify and reimburse Case for the monthly amounts above the cap. These rulings have been appealed. In the meantime, El Paso will indemnify Case for any payments Case makes above the cap. While we believe we have meritorious defenses to the plaintiffs claims and to Case s crossclaim, if we were required to ultimately pay for all future amounts above the cap, and if Case were not found to be responsible for these amounts, our exposure could be as high as $400 million, on an undiscounted basis.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. In January 2005, a purported class action lawsuit styled *Leggett et al. v Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of all residential and commercial purchasers of natural gas in the state of Tennessee. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing

false

price reporting information to industry trade publications that published gas indices. We have also had similar purported class claims filed in the U.S. District Court for the Eastern District of California by and on behalf of commercial and residential customers in that state. The case of *Texas-Ohio Energy, Inc. v. CenterPoint Energy, Inc., et al.* was filed in November 2003; *Fairhaven Power v. El Paso Corporation, et al.* was filed in September 2004; *Utility Savings and Refund Services, et al. v. Reliant Energy, et al.* was filed in December 2004; *Abelman Art Glass, et al. v. Encana Corporation, et al.* was filed in December 2004; and *Ever-Bloom Inc. v. AEP Energy Services Inc. et al* was filed in June 2005, and *FLI Liquidating Trust v. Oneok Inc.* was filed in July 2005. The defendants motion to dismiss in the *Texas-Ohio* matter has been granted and similar motions are anticipated in the other cases. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties due to the alleged mismeasurement. The plaintiff seeks royalties along with interest, expenses, and punitive damages. The plaintiff also seeks injunctive relief with regard to future gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss were argued before a representative appointed by the court. In May 2005, the representative issued its recommendation, which if adopted by the district court judge, will result in the dismissal on jurisdictional grounds of six of the seven *Qui Tam* actions filed by Grynberg against El Paso subsidiaries. The seventh case involves only a few midstream entities owned by El Paso, which have meritorious defenses to the underlying claims. If the district court judge adopts the representative s recommendations, an appeal by the plaintiff of the district court s order is likely. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has since been filed as to the heating content claims. Motions for class certification have been briefed and argued in both proceedings, and the parties are awaiting the court s ruling. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs have filed reports alleging damages of approximately $480 million which includes alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in Oklahoma, plus interest from the time such amounts were allegedly due. The plaintiffs have also requested punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners. The consolidated class action has been set for trial in the fourth quarter of 2005. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Resources, Inc., and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third

action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed by agreement of the parties. We believe we have substantial defenses to the plaintiffs claims as well as to the claims for indemnity by Burlington. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA, which is scheduled for hearing in the first quarter of 2006. A Curitiba court has ruled that the arbitration clause in the PPA is invalid. The project company is appealing this ruling. Our investment in the Araucaria project was $187 million at June 30, 2005. We have political risk insurance that covers a substantial portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are paid by Petrobras until August 2007 under a participation agreement. Petrobras has filed a notice of arbitration with an international arbitration institution that effectively seeks rescission of the participation agreement and reimbursement of a portion of the capacity payments that it has made. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras obligation to provide a firm gas supply to the project through 2012. Beginning in December 2004, and continuing through the second quarter of 2005, Petrobras has failed to make payments that were due under the participation agreement. Various actions have been filed in Brazilian courts and before the arbitration panel to address Petrobras payment obligations during the pendency of the arbitration proceedings. Although various appellate proceedings in such actions are outstanding, currently the arbitration panel has required Petrobras to pay past due amounts and additional amounts owed during the arbitration process, subject to Macae s obligation to post a bank guarantee as security for any repayment obligation if Petrobras were to prevail on the merits. Due to this ongoing dispute, during the first six months of 2005 we have not recognized approximately $99 million of revenues under our participation agreement, because of the uncertainty about their collectibility. We believe we have substantial defenses to the claims of Petrobras and will vigorously defend our legal rights. In addition, we will continue to seek reasonable negotiated settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $276 million at June 30, 2005, and Petrobras non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $276 million of debt as current. We also have restricted cash balances of approximately $14 million as of June 30, 2005, which are reflected in current assets, related to required debt service reserve balances, debt service payment accounts and funds held for future distribution by Macae. We have also issued cash collateralized letters of credit of approximately $47 million as part of funding the required debt service reserve accounts. The restricted cash related to these letters of credit has also been classified as a current asset. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise certain remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

In light of the pending arbitration proceedings, and as a result of continued negotiations and discussions with Petrobras regarding this dispute, we may sell our investment in the Macae power facility to Petrobras in

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connection with the eventual resolution of this dispute or exchange our interest in the plant for Brazilian production properties owned by Petrobras. We recorded a $276 million impairment charge on our investment and also reserved $18 million of related receivables in the second quarter of 2005 based on information regarding the potential value we may receive from the resolution of this matter. In the event that the lenders call the loans and ultimately foreclose on the project, we may incur additional losses of up to approximately $204 million. As new information becomes available or future material developments occur, we will reassess the carrying value of our interests in this project.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE s potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney s fees, and court costs. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. On April 20, 2005, the judge denied a motion by defendants to dismiss the lawsuits. In that opinion the Court recognized, for certain states, a potential commingled product market share basis for collective liability. Our costs and legal exposure related to these lawsuits are not currently determinable.

Wise Arbitration. William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached his employment agreement, as well as several other alleged agreements by failing to make certain payments to him following his departure from El Paso in 2003. Although Mr. Wise initially sought approximately $20 million in additional compensation, Mr. Wise revised his claims and sought cash compensation in excess of $15 million, as well as injunctive relief that would require us to make certain future payments. The arbitration panel issued an interim decision in July 2005 generally finding that Mr. Wise was not entitled to any payments other than those set forth in his employment agreement that governed his post employment compensation. A final decision will be issued following additional briefings.

Government Investigations

Power Restructuring. El Paso has cooperated with the SEC with regard to an investigation of our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including, in particular, the Eagle Point restructuring transaction completed in 2002. In July 2005, we were informed by the staff of the SEC that they do not intend to recommend any enforcement action concerning this investigation.

Wash Trades. In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning round trip or wash trades. We have complied with those requests. We have also cooperated with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production and the restatement of such hedges. On May 24, 2005, we received a subpoena from the SEC requesting the production of documents related to such production hedges. We are cooperating with the SEC investigation.

Price Reporting. In October 2002, the FERC issued data requests regarding price reporting of transactional data to the energy trade press. We provided information to the FERC, the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney s investigation of this matter.

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Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand jury subpoenas for documents with regard to these reserve revisions and we cooperated with the U.S. Attorney s investigation related to this matter. In June 2005, we were informed that the U.S. Attorney s office closed this investigation and will not pursue prosecution at this time. We will continue to cooperate with the SEC in its investigation related to such reserve revisions.

Iraq Oil Sales. In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records related to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with The Coastal Corporation s and El Paso s participation in the Oil for Food Program. In June 2005, we received an additional request for documents and information from the SEC. We have also received informal requests for information and documents from the United States Senate s Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to Coastal s purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney s, the SEC s, the Senate Subcommittee s, and the House Committee s investigations of this matter.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation s Office of Pipeline Safety (DOT) issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. In April 2003, the National Transportation Safety Board (NTSB) issued its final report on the rupture, finding that the rupture was probably caused by internal corrosion that was not detected by EPNG s corrosion control program. In December 2003, this matter was referred by the DOT to the Department of Justice (DOJ). We recently entered into a tolling agreement with the DOJ to attempt to reach resolution of this civil proceeding. In addition, we, EPNG and several of its current and former employees had received several federal grand jury subpoenas for documents or testimony related to the Carlsbad rupture. In July 2005, we were informed by the DOJ that the United States is not pursuing any criminal prosecutions associated with the rupture.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

Rates and Regulatory Matters

Selective Discounting Notice of Inquiry (NOI). In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. In May 2005, the FERC issued an order reaffirming its prior practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons when the discount is given to meet competition from another natural gas pipeline.

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, 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 our 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

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the technical conference within 150 days of the order and held the hearing pending resolution of the various matters identified for consideration at the technical conference. We anticipate continued discussions with intervening parties and are uncertain of the settlement of this rate case.

SNG Rate Case. 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 29, 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 our 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.

Other Contingencies

Navajo Nation. Nearly 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on property inside the Navajo Nation. We currently pay approximately $2 million per year for the real property interests, such as easements, leases and rights-of-way located on Navajo Nation trust lands. These real property interests are scheduled to expire in October 2005. We are in negotiations with the Navajo Nation to obtain their consent to renew these interests, but the Navajo Nation has made a demand of more than ten times the existing fee. We will continue to negotiate in order to reach an agreement on a renewal, but we are also exploring other options including potentially developing collaborative projects to benefit the Navajo Nation in lieu of cash payments. If we are unable to reach a new consent agreement with the Navajo Nation (which is arguably required for renewal of the U.S. Department of the Interior s extension of EPNG s current easement across trust lands) the impact is uncertain. Historically, we have continued renewal negotiations with the Navajo Nation substantially beyond the prior easement s expiration, without litigation or interruption to our operations. As our renewal efforts continue, we may incur litigation and other costs and, ultimately, higher consent fees. Although the FERC has rejected a request made 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 the Navajo right-of-way, the FERC did invite EPNG to seek permission to include the cost of the right-of-way 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.

Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil, including our Macae project discussed previously. Our total investment in Brazil was approximately $1.3 billion as of June 30, 2005. In a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. In addition, although the Macae power plant is currently dispatching only small quantities of electricity, a recent rupture in the local distribution company s pipeline that supplies it gas has resulted in the plant temporarily being unable to generate electricity. We are currently assessing the time it will take for the pipeline to be repaired. We also own an investment in the Porto Velho power plant. The Porto Velho project is in the process of negotiating certain provisions of its power purchase agreements (PPA) with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant s capacity. The project expects to repair the steam

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turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the ongoing contract negotiations do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was approximately $316 million at June 30, 2005.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of June 30, 2005, we had approximately $172 million accrued, net of related insurance receivables, for all outstanding legal and other contingent matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2005, we had accrued approximately $371 million, including approximately $358 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $13 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $371 million accrual, $100 million was reserved for facilities we currently operate, and $271 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $371 million to approximately $531 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 ($289 million to $449 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	June 30, 2005	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 100	$ 111
Non-operating	244	374
Superfund	27	46
Total	$ 371	$ 531

Below is a reconciliation of our accrued liability from January 1, 2005, to June 30, 2005 (in millions):

Balance as of January 1, 2005	$ 380
Additions/adjustments for remediation activities	15
Payments for remediation activities	(26)
Other changes, net	2
Balance as of June 30, 2005	$ 371

For the last six months of 2005, we estimate that our total remediation expenditures will be approximately $43 million. In addition, we expect to make capital expenditures for environmental matters of approximately $92 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

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Polychlorinated Biphenyls (PCB) Cost Recoveries. Pursuant to a consent order executed by Tennessee Gas Pipeline (TGP), our subsidiary, in May 1994, with the EPA, TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCBs, and certain other hazardous materials. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its PCB remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of June 30, 2005, TGP had pre-collected PCB costs by approximately $129 million. The pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of June 30, 2005, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $102 million for the estimated future refund obligations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 48 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of June 30, 2005, we have estimated our share of the remediation costs at these sites to be between $27 million and $46 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. See our 2004 Notes to Consolidated Financial Statements, Note 15, on page F-79, for a description of these commitments. As of June 30, 2005, we had approximately $28 million of both financial and performance guarantees not otherwise reflected in our financial statements. We also periodically provide indemnification arrangements related to assets or businesses we have sold. As of June 30, 2005, we had accrued $56 million related to these arrangements.

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11. Retirement Benefits

The components of net benefit cost for our pension and postretirement benefit plans for the periods ended June 30 are as follows:

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004	2005	2004	2005	2004
	(In millions)				(In millions)			
Service cost	$ 6	$ 8	$	$	$ 12	$ 16	$	$
Interest cost	29	30	8	8	58	61	15	16
Expected return on plan assets	(42)	(47)	(3)	(3)	(84)	(95)	(6)	(6)
Amortization of net actuarial loss	16	12		1	32	24		2
Amortization of transition obligation			2	2			4	4
Amortization of prior service cost [1]	(1)	(1)			(2)	(2)		
Net benefit cost	$ 8	$ 2	$ 7	$ 8	$ 16	$ 4	$ 13	$ 16

[1] As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

In 2004, we adopted FSP No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $49 million. In addition, it reduced our net periodic benefit cost by approximately $3 million for the first six months of 2005. Our actual and expected contributions for 2005 were not reduced by subsidies under this legislation.

We made $33 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the six months ended June 30, 2005 and 2004. We expect to contribute an additional $2 million to the SERP and $34 million to our other postretirement plans for the remainder of 2005. Contributions to our other retirement benefit plans will be less than $1 million in 2005.

12. Capital Stock

Convertible Perpetual Preferred Stock

In April 2005, we issued $750 million of convertible perpetual preferred stock. Cash dividends on the preferred stock are paid quarterly at the rate of 4.99% per annum. Each share of the preferred stock is convertible at the holder s option, at any time, subject to adjustment, into 76.7754 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately $13.03 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or adjustments to the current rate of dividends on our common stock. We will be able to cause the preferred stock to be converted into common stock after five years if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds of $723 million from the issuance of the preferred stock, together with cash on hand, was used to prepay our Western Energy Settlement of approximately $442 million in April 2005, and to pay the redemption price (an aggregate of $300 million plus accrued dividends of $3 million) of the 6,000,000 outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co., (EPTP) in May 2005.

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Dividends

During the six months ended June 30, 2005, we paid dividends of approximately $51 million to common stockholders. The dividends on our common stock were treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We have also paid dividends of approximately $26 million subsequent to June 30, 2005. On July 28, 2005, the Board of Directors declared a quarterly dividend of $0.04 per share on the company s outstanding common stock. The dividend will be payable on October 3, 2005 to shareholders of record on September 2, 2005.

On May 26, 2005 and July 28, 2005, the Board of Directors declared quarterly dividends of $10.53 and $12.47 per share on our 4.99% convertible perpetual preferred stock. The first dividend was paid on July 1, 2005 to stockholders of record on June 15, 2005. The second dividend will be payable on October 3, 2005 to stockholders of record on September 15, 2005.

We expect dividends paid on our common and preferred stock in 2005 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

13. Business Segment Information

Our regulated business consists of our Pipelines segment, while our non-regulated 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 operations include our general and administrative functions, as well as a telecommunications business and various other contracts and assets, all of which are immaterial. During the second quarter of 2005, we reclassified our south Louisiana gathering and processing assets, which were part of our Field Services segment, as discontinued operations. 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 substantial 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 operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Total EBIT	$ 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)

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The following tables reflect our segment results as of and for the periods ended June 30:

	Regulated		Non-regulated				
Quarter Ended June 30,	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$ 634	$ 171[2]	$ 240	$ 112	$ 23	$ 24	$ 1,204
Intersegment revenues	19	281[2]	(261)	(3)	5	(21)	20[3]
Operation and maintenance	214	99	9	78	4	34	438
Depreciation, depletion and amortization	108	157	1	10	1	17	294
(Gain) loss on long-lived assets	(3)			361	6	(4)	360
Operating income (loss)	$ 262	$ 175	$ (32)	$ (357)	$ (5)	$ (36)	$ 7
Earnings (losses) from unconsolidated affiliates	38			(59)	2		(19)
Other income, net	9	1	2	35		24	71
EBIT	$ 309	$ 176	$ (30)	$ (381)	$ (3)	$ (12)	$ 59
2004							
Revenues from external customers	$ 595	$ 144[2]	$ 187	$ 202	$ 375	$ 29	$ 1,532
Intersegment revenues	22	286[2]	(328)	34	53	(75)	(8)[3]
Operation and maintenance	172	77	10	97	25	(8)	373
Depreciation, depletion and amortization	101	131	3	12	4	12	263
(Gain) loss on long-lived assets				16	6	(5)	17
Operating income (loss)	$ 260	$ 202	$ (154)	$ 56	$ 7	$ (1)	$ 370
Earnings from unconsolidated affiliates	41	2		24	31		98
Other income (expense), net	7		2	22	(11)	10	30
EBIT	$ 308	$ 204	$ (152)	$ 102	$ 27	$ 9	$ 498

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the quarters ended June 30, 2005 and 2004, we recorded an intersegment revenue elimination of $39 million and $75 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the Corporate column, to remove intersegment transactions.

(2)

Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

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Six Months Ended June 30,	Regulated Pipelines	Non-regulated Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$ 1,382	$ 302[2]	$ 333	$ 191	$ 65	$ 51	$ 2,324
Intersegment revenues	39	589[2]	(529)	(5)	11	(63)	42[3]
Operation and maintenance	417	183	19	129	3	129	880
Depreciation, depletion and amortization	219	303	2	22	2	26	574
(Gain) loss on long-lived assets	(10)			388	7	(4)	381
Operating income (loss)	$ 624	$ 355	$ (218)	$ (395)	$ (3)	$ (127)	$ 236
Earnings (losses) from unconsolidated affiliates	76			(87)	182		171
Other income, net	21	4	3	51		25	104
EBIT	$ 721	$ 359	$ (215)	$ (431)	$ 179	$ (102)	$ 511
2004							
Revenues from external customers	$ 1,293	$ 277[2]	$ 368	$ 351	$ 720	$ 72	$ 3,081
Intersegment revenues	45	599[2]	(668)	92	95	(163)	
Operation and maintenance	352	162	23	194	51	(8)	774
Depreciation, depletion and amortization	201	271	6	28	7	25	538
(Gain) loss on long-lived assets	(1)			256	8	(8)	255
Operating income (loss)	$ 608	$ 405	$ (329)	$ (148)	$ 17	$ 6	$ 559
Earnings from unconsolidated affiliates	74	3		40	68		185
Other income (expense), net	12		13	41	(22)	30	74
EBIT	$ 694	$ 408	$ (316)	$ (67)	$ 63	$ 36	$ 818

[1] Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the six months ended June 30, 2005 and 2004, we recorded an intersegment revenue elimination of $103 million and $163 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the Corporate column, to remove intersegment transactions.

[2] Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which

is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

Total assets by segment are presented below:

	June 30, 2005	December 31, 2004
	(In millions)	
Regulated		
Pipelines	$ 16,056	$ 15,988
Non-regulated		
Production	4,518	4,080
Marketing and Trading	2,718	2,404
Power	2,348	3,599
Field Services	121	686
Total segment assets	25,761	26,757
Corporate	3,722	4,520
Discontinued operations	193	106
Total consolidated assets	$ 29,676	$ 31,383

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14. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines and power generation plants. Our income statement reflects our share of net earnings from unconsolidated affiliates, which includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments. In addition, for investments we are in the process of selling, or for those that have been previously impaired, we evaluate the income generated by the investment and record an amount that we believe is realizable. For losses, we assess whether such amounts have already been considered in a related impairment. Our net ownership interest and earnings (losses) from our unconsolidated affiliates are as follows:

	Net Ownership Interest	Earnings (Losses) from Unconsolidated Affiliates		Earnings (Losses) from Unconsolidated Affiliates	
		Quarter Ended June 30,		Six Months Ended June 30,	
	June 30, 2005	2005	2004	2005	2004
	(Percent)	(In millions)			
Domestic:					
Enterprise Products Partners, L.P.[1]		$	$	$ 183	$
GulfTerra Energy Partners, L.P.[1]			29		63
Citrus	50	18	21	33	28
Midland Cogeneration Venture (MCV)[2]	44	(4)	(2)	(3)	3
Great Lakes Gas Transmission	50	14	16	31	36
Other Domestic Investments	various	4	8	6	9
Total domestic		32	72	250	139
Foreign:					
Asia Investments[3]	various		20	(68)	41
Central American Investments[4]	various	(55)		(49)	3
PPN[5]				22	
Other Foreign Investments	various	4	6	16	2
Total foreign		(51)	26	(79)	46
Total earnings from unconsolidated affiliates		$ (19)	$ 98	$ 171	$ 185

(1) In January 2005, we sold all of these remaining interests to Enterprise and recognized a $183 million gain.

(2) Our proportionate share of MCV s losses, after intercompany eliminations, was $14 million during the second quarter of 2005. We did not record our remaining proportionate share of MCV s losses as these losses resulted

primarily from changes in the fair value of their derivative contracts, which we believe did not affect the value of our investment and would not be realized. We did not recognize substantially all of our proportionate share of MCV s earnings, after intercompany eliminations, of approximately $58 million during the six months ended June 30, 2005 for the same reasons.

(3) Consists of our investments in 12 power plants, including Korea Independent Energy Corporation, Meizhou Wan Generating, Habibullah Power and Saba Power Company. Our proportionate share of earnings reported by our Asia investments was $19 million and $44 million, for the quarter and six months ended June 30, 2005. We decreased our proportionate share of equity earnings for our Asia investments by $8 million and $19 million, for the quarter and six months ended June 30, 2005, to reflect the amount of earnings we believe will be realized.

(4) Consists of our investments in 6 power plants. Our proportionate share of earnings reported by our Central American investments was $2 million and $8 million for the quarter and six months ended June 30, 2005. We recorded an impairment of $57 million during the quarter ended June 30, 2005 related to these investments.

(5) We sold our interest in March 2005 and recorded a $22 million gain.

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The table below reflects our recognized impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates for the periods ended June 30:

Investment	Quarter Ended June 30,	Six Months Ended June 30,
	Pre-tax Gain (Loss)	
	(In millions)	
2005		
Impairments		
Asia power investments[1]	$ (11)	$ (93)
Central American power investments[1]	(57)	(57)
Other foreign investments[1]	(16)	(17)
Midland Cogeneration Venture[2]	(4)	(4)
Gain on sale of PPN		22
Gain on sale of Enterprise		183
Other	1	(2)
	$ (87)	$ 32
2004		
Impairments		
Milford power facility[1]	$	$ (2)
Power plants held for sale[1]	(19)	(35)
Other	1	(5)
	$ (18)	$ (42)

(1) We impaired our interests in these investments based on information received regarding the potential value we may receive when we sell the investments.

(2) We impaired our investment in this power facility due to delays in the timing of expected cash flow receipts from this investment.

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The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates, including affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest for the periods ended June 30:

	Quarter Ended June 30,			Six Months Ended June 30,		
	MCV	Other Investments	Total	MCV	Other Investments	Total
		(In millions)			(In millions)	
2005						
Operating results data						
Revenues	$ 62	$ 342	$ 404	$ 127	$ 625	$ 752
Operating expenses	69	208	277	34	384	418
Income (loss) from continuing operations	(17)	67	50	75	134	209
Net income (loss)[1]	(17) [2]	67	50	75	134	209
2004						
Operating results data						
Revenues	$ 69	$ 558	$ 627	$ 139	$ 1,072	$ 1,211
Operating expenses	60	359	419	113	691	804
Income (loss) from continuing operations	(2)	107	105	3	214	217
Net income (loss)[1]	(2)	112	110	3	216	219

[1] Includes net income of $10 million and $7 million for the quarters ended June 30, 2005 and 2004, and $14 million and $21 million for the six months ended June 30, 2005 and 2004, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

[2] Includes $3 million of losses during the second quarter of 2005 and $17 million of earnings during the six months ended June 30, 2005 attributable to transactions with El Paso which were eliminated.

We received distributions and dividends from our investments of $64 million and $72 million for each of the quarters ended June 30, 2005 and 2004, and $147 million and $168 million for the six months ended June 30, 2005 and 2004.

Related Party Transactions

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows the income statement impact on transactions with our affiliates for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
			(In millions)	
Operating revenue	$ 43	$ 68	$ 92	$ 118
Cost of sales	2	38	6	60

Reimbursement for operating expenses		34	1	65
Other income	5	4	9	9

GulfTerra Energy Partners, L.P.

Prior to the sale of our interests in GulfTerra to Enterprise in September 30, 2004, our Field Services segment managed GulfTerra s daily operations and performed all of GulfTerra s administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributed to our income through our general partner interest and our ownership of common and preference units. We did not have any loans to or from GulfTerra.

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In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge and form the second largest publicly traded energy partnership in the United States. On July 29, 2004, GulfTerra s unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004. In January 2005, we sold our remaining 9.9 percent interest in the general partner of Enterprise and approximately 13.5 million common units in Enterprise for $425 million, which resulted in a gain of approximately $183 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, which resulted in a loss of approximately $1 million.

During 2004, our segments conducted transactions in the ordinary course of business with GulfTerra, including operational services and sales of natural gas under transportation contracts, the net financial impact of which are included in revenues. We incurred losses on our transportation contracts with GulfTerra, net of other revenues, of $4 million for the quarter and six months ended June 30, 2004. Expenses paid to GulfTerra were $36 million and $56 million and reimbursements from GulfTerra were $23 million and $45 million for the quarter and six months ended June 30, 2004.

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $60 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. The country is emerging from an economic crisis that developed in 2003 resulting in a significant devaluation of the Dominican peso. As a result of these economic conditions, combined with the high prices on imported fuels, and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities were delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic. The government of the Dominican Republic has signed an agreement with the IMF and World Bank that restores lending programs and provides for the recovery of the power sector. This led to the government s agreement to keep payments current and address the arrears to the generating companies. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales, which may affect CEPP s ability to operate. The local court decision has been stayed pending our appeal to the Supreme Court of the Dominican Republic. We continue to monitor the economic and payment situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that future impairments of these investments may occur.

Bolivia. We own an eight percent interest in the Bolivia to Brazil pipeline in which we have approximately $96 million of exposure, including guarantees, as of June 30, 2005. During the second quarter of 2005, political disputes in Bolivia related to pressure to nationalize the energy industry led to the resignation of the president of Bolivia. Additionally, recent changes in Bolivian law also increased the combined rate of production taxes and royalties to 50 percent and required that existing exploration contracts be renegotiated. Further deterioration of the political environment in Bolivia could potentially lead to a disruption or cessation of the supply of gas from Bolivia and impact the payments that the Bolivia to Brazil pipeline receives from Petrobras. We continue to monitor the political situation in Bolivia and as new information becomes available or future material developments arise, it is possible that a future impairment of our investment may occur.

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Berkshire Power Project. We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. Berkshire s lenders have asserted that Berkshire is in default on its loan agreement (but no remedies have been exercised at this point). We supply natural gas to Berkshire under a fuel management agreement. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of delayed payments based on Berkshire s inability to generate adequate cash flows related to 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 fuel deliveries are not paid for under this agreement because of Berkshire s inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders.

Brazil. For contingent matters that could impact our investments in Brazil, see Note 10.

Duke Litigation. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus), in which we own a 50 percent equity interest, has filed suit against Duke Energy LNG Sales, Inc. (Duke) and PanEnergy Corp., an affiliate of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. Duke has filed in federal court an amended counter claim joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke s motion, which is currently pending before the court. An unfavorable outcome on this matter could impact the value of our investment in Citrus.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,		
	2004 (Restated)	2003 (Restated)	2002 (Restated)
Operating revenues			
Pipelines	$ 2,651	$ 2,647	$ 2,610
Production	1,735	2,141	1,931
Marketing and Trading	(508)	(635)	(1,324)
Power	795	1,176	1,672
Field Services	1,362	1,529	2,029
Corporate and eliminations	(161)	(190)	(37)
	5,874	6,668	6,881
Operating expenses			
Cost of products and services	1,363	1,818	2,468
Operation and maintenance	1,872	2,010	2,091
Depreciation, depletion and amortization	1,088	1,176	1,159
Loss on long-lived assets	1,108	860	181
Western Energy Settlement		104	899
Taxes, other than income taxes	253	295	254
	5,684	6,263	7,052
Operating income (loss)	190	405	(171)
Earnings (losses) from unconsolidated affiliates	546	363	(214)
Other income	193	203	197
Other expenses	(99)	(202)	(239)
Interest and debt expense	(1,607)	(1,791)	(1,297)
Distributions on preferred interests of consolidated subsidiaries	(25)	(52)	(159)
Loss before income taxes	(802)	(1,074)	(1,883)
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)
Basic and diluted loss per common share			
Loss from continuing operations	$ (1.30)	$ (0.99)	$ (2.22)
Discontinued operations, net of income taxes	(0.18)	(2.14)	(0.76)

Cumulative effect of accounting changes, net of income taxes		(0.02)	(0.37)
Net loss	$ (1.48)	$ (3.15)	$ (3.35)
Basic and diluted average common shares outstanding	639	597	560

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31,	
	2004 (Restated)	**2003 (Restated)**
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,117	$ 1,429
Accounts and notes receivable		
Customer, net of allowance of $199 in 2004 and $273 in 2003	1,388	2,039
Affiliates	133	189
Other	188	245
Inventory	168	181
Assets from price risk management activities	601	706
Margin and other deposits held by others	79	203
Assets held for sale and from discontinued operations	181	2,538
Restricted cash	180	590
Deferred income taxes	418	593
Other	179	210
Total current assets	5,632	8,923
Property, plant and equipment, at cost		
Pipelines	19,418	18,563
Natural gas and oil properties, at full cost	14,968	14,689
Power facilities	1,550	1,660
Gathering and processing systems	171	334
Other	882	998
	36,989	36,244
Less accumulated depreciation, depletion and amortization	18,177	18,049
Total property, plant and equipment, net	18,812	18,195
Other assets		
Investments in unconsolidated affiliates	2,614	3,409
Assets from price risk management activities	1,584	2,338
Goodwill and other intangible assets, net	428	1,082
Other	2,313	2,996
	6,939	9,825
Total assets	$ 31,383	$ 36,943

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS (Continued)
(In millions, except share amounts)

	December 31, 2004 (Restated)	December 31, 2003 (Restated)
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,052	$ 1,552
Affiliates	21	26
Other	483	438
Short-term financing obligations, including current maturities	955	1,457
Liabilities from price risk management activities	852	734
Western Energy Settlement	44	633
Liabilities related to assets held for sale and discontinued operations	12	933
Accrued interest	333	391
Other	820	910
Total current liabilities	4,572	7,074
Long-term financing obligations, less current maturities	18,241	20,275
Other		
Liabilities from price risk management activities	1,026	781
Deferred income taxes	1,312	1,558
Western Energy Settlement	351	415
Other	2,076	2,047
	4,765	4,801
Commitments and contingencies		
Securities of subsidiaries		
Securities of consolidated subsidiaries	367	447
Stockholders equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 651,064,508 shares in 2004 and 639,299,156 shares in 2003	1,953	1,917
Additional paid-in capital	4,538	4,576
Accumulated deficit	(2,809)	(1,862)
Accumulated other comprehensive income (loss)	1	(40)
Treasury stock (at cost); 7,767,088 shares in 2004 and 7,097,326 shares in 2003	(225)	(222)
Unamortized compensation	(20)	(23)
Total stockholders equity	3,438	4,346

Total liabilities and stockholders equity	$ 31,383	$ 36,943

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2004 (Restated)[1]	**2003 (Restated)[1]**	**2002 (Restated)[1]**
Cash flows from operating activities			
Net loss	$ (947)	$ (1,883)	$ (1,875)
Less loss from discontinued operations, net of income taxes	(114)	(1,279)	(425)
Net loss before discontinued operations	(833)	(604)	(1,450)
Adjustments to reconcile net loss to net cash from operating activities			
Depreciation, depletion and amortization	1,088	1,176	1,159
Western Energy Settlement		94	899
Deferred income tax benefit	(32)	(614)	(685)
Cumulative effect of accounting changes		9	208
Loss on long-lived assets	1,108	785	181
Losses (earnings) from unconsolidated affiliates, adjusted for cash distributions	(211)	(17)	521
Other non-cash income items	447	399	255
Asset and liability changes			
Accounts and notes receivable	471	2,552	(629)
Inventory	9	76	248
Change in non-hedging price risk management activities, net	191	85	1,074
Accounts payable	(295)	(2,127)	(114)
Broker and other margins on deposit with others	121	623	(257)
Broker and other margins on deposit with us	(24)	32	(647)
Western Energy Settlement liability	(626)		
Other asset and liability changes			
Assets	(20)	(267)	54
Liabilities	(301)	102	(139)
Cash provided by continuing activities	1,093	2,304	678
Cash provided by (used in) discontinued activities	223	25	(242)
Net cash provided by operating activities	1,316	2,329	436
Cash flows from investing activities			
Additions to property, plant and equipment	(1,782)	(2,328)	(3,243)

Purchases of interests in equity investments	(34)	(33)	(299)
Cash paid for acquisitions, net of cash acquired	(47)	(1,078)	45
Net proceeds from the sale of assets and investments	1,927	2,458	2,779
Net change in restricted cash	578	(534)	(260)
Net change in notes receivable from affiliates	120	(43)	4
Other	(1)		22
Cash provided by (used in) continuing activities	761	(1,558)	(952)
Cash provided by (used in) discontinued activities	1,142	369	(303)
Net cash provided by (used in) investing activities	1,903	(1,189)	(1,255)

(1) Only individual line items in cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
(In millions)

	Year Ended December 31,		
	2004 (Restated)[1]	2003 (Restated)[1]	2002 (Restated)[1]
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	1,300	3,633	4,294
Payments to retire long-term debt and other financing obligations	(2,306)	(2,824)	(1,777)
Net borrowings/(repayments) under revolving and other short-term credit facilities	(850)	(650)	154
Net proceeds from issuance of notes payable		84	
Repayment of notes payable	(214)	(8)	(94)
Payments to minority interest and preferred interest holders	(35)	(1,277)	(861)
Issuances of common stock	73	120	1,053
Dividends paid	(101)	(203)	(470)
Other	(33)	(177)	(476)
Contributions from (distributions to) discontinued operations	1,000	394	(1,106)
Cash provided by (used in) continuing activities	(1,166)	(908)	717
Cash provided by (used in) discontinued activities	(1,365)	(394)	555
Net cash provided by (used in) financing activities	(2,531)	(1,302)	1,272
Change in cash and cash equivalents	688	(162)	453
Less change in cash and cash equivalents related to discontinued operations			10
Change in cash and cash equivalents from continuing operations	688	(162)	443
Cash and cash equivalents			
Beginning of period	1,429	1,591	1,148
End of period	$ 2,117	$ 1,429	$ 1,591
Supplemental Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 1,536	$ 1,657	$ 1,291
Income tax payments (refunds)	68	23	(106)

(1) Only individual line items in cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In millions except for per share amounts)

	For the Years Ended December 31,					
	2004 (Restated)		2003 (Restated)		2002 (Restated)	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	639	$ 1,917	605	$ 1,816	538	$ 1,615
Equity offering					52	155
Exchange of equity security units			15	45		
Western Energy Settlement equity offerings	9	26	18	53		
Other, net	3	10	1	3	15	46
Balance at end of year	651	1,953	639	1,917	605	1,816
Additional paid-in capital:						
Balance at beginning of year		4,576		4,444		3,130
Compensation related issuances		15		8		57
Tax effects of equity plans		5		(26)		15
Equity offering						846
Exchange of equity security units				189		
Conversion of FELINE PRIDES[SM]						423
Western Energy Settlement equity offerings		46		67		
Dividends ($0.16 per share)		(104)		(96)		
Other				(10)		(27)
Balance at end of year		4,538		4,576		4,444
Accumulated deficit (Restated):						
Balance at beginning of year		(1,862)		21		2,387
Net loss		(947)		(1,883)		(1,875)
Dividends ($0.87 per share)						(491)
Balance at end of year		(2,809)		(1,862)		21
Accumulated other comprehensive income (loss)						
Balance at beginning of year		(40)		(235)		(18)
Other comprehensive income (loss)		41		195		(217)
Balance at end of year		1		(40)		(235)

Treasury stock, at cost:						
Balance at beginning of year	(7)	(222)	(6)	(201)	(8)	(261)
Compensation related issuances		9			3	79
Other	(1)	(12)	(1)	(21)	(1)	(19)
Balance at end of year	(8)	(225)	(7)	(222)	(6)	(201)
Unamortized compensation:						
Balance at beginning of year		(23)		(95)		(187)
Issuance of restricted stock		(28)		(1)		(36)
Amortization of restricted stock		23		60		73
Forfeitures of restricted stock		9		15		15
Other		(1)		(2)		40
Balance at end of year		(20)		(23)		(95)
Total stockholders equity	643	$ 3,438	632	$ 4,346	599	$ 5,750

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2004 (Restated)	**2003 (Restated)**	**2002 (Restated)**
Net loss	$ (947)	$ (1,883)	$ (1,875)
Foreign currency translation adjustments (net of income tax of $38 in 2004 and $51 in 2003)	11	108	(20)
Minimum pension liability accrual (net of income tax of $11 in 2004, $7 in 2003 and $20 in 2002)	(22)	11	(35)
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $8 in 2004, $50 in 2003 and $53 in 2002)	22	101	(90)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $8 in 2004, $11 in 2003 and $40 in 2002)	30	(25)	(73)
Other			1
Other comprehensive income (loss)	41	195	(217)
Comprehensive loss	$ (906)	$ (1,688)	$ (2,092)

See accompanying notes.

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EL PASO CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our results for all periods presented reflect our Canadian and certain other international natural gas and oil production operations, petroleum markets and coal mining businesses as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications did not impact our reported net loss or stockholders equity.

Restatements

Overview. The financial statements in this prospectus have been restated for several matters. As originally filed in our 2004 Form 10-K, our 2002 financial statements were restated to reflect a correction in the manner in which we adopted SFAS No. 141, *Business Combinations*, and SFAS No. 142 *Goodwill and Other Intangible Assets*. Our 2003 financial statements were initially restated to record the tax benefit of our Canadian exploration and production operations as discontinued operations rather than continuing operations as originally presented. We further restated our financial statements in 2003 and restated our financial statements in 2004 to correct the accounting for currency translation adjustments (CTA) and related income taxes. Each of these restatements is explained more fully below.

Goodwill. 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 Statement of Financial Accounting Standards (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 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 related 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. Below are the effects of our restatements:

	For the Year Ended December 31, 2002	
	As Reported	As Restated
	(In millions except per common share amounts)	
Income Statement:		
Earnings (losses) from unconsolidated affiliates	$ (226)	$ (214)
Income taxes (benefit)	(621)	(641)
Cumulative effect of accounting changes, net of income taxes	(54)	(208)
Net loss	(1,753)	(1,875)
Basic and diluted net loss per share:		

Cumulative effect of accounting changes, net of income taxes	(0.10)	(0.37)
Net loss	(3.13)	(3.35)

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	As of December 31,			
	2002		2003	
	As Reported	As Restated	As Reported	As Restated
Balance Sheet:				
Investments in unconsolidated affiliates	$ 4,891	$ 4,749	$ 3,551	$ 3,409
Non-current deferred income tax liabilities	2,094	2,074	1,571	1,551
Stockholders equity	5,872	5,750	4,474	4,352

The restatement did not impact 2003 and 2004 reported income amounts, except that we recorded an adjustment related to these periods of $(19) million in the fourth quarter of 2004. The components of this adjustment were immaterial to all previously reported interim and annual periods.

Income Taxes. In our discontinued Canadian exploration and production operations, we had previously recorded deferred tax benefits of $82 million in continuing operations that should have been reflected in discontinued operations. As a result, we were required to restate our 2003 financial statements, and related quarterly financial information, to reclassify this amount from continuing operations to discontinued operations. This restatement, which we originally reported in Amendment No. 1 to our 2004 Form 10-K, did not impact our reported net loss, balance sheet amounts or cash flows as of and for the year ended December 31, 2003.

Cumulative Foreign Currency Translation Adjustments (CTA). We determined that our CTA balances contained amounts related to businesses and investments that had been previously sold or abandoned. These businesses and investments primarily included our discontinued Canadian exploration and production operations and certain of our discontinued petroleum markets activities, foreign plants in our Power segment, and certain foreign operations in our Marketing and Trading segment and in our corporate activities. The adjustment of these CTA balances also affected losses we recorded in 2004 on several of these assets and investments, including impairment charges.

In conjunction with the revisions for CTA, we also determined that upon initially recognizing U.S. deferred income taxes on investments in certain of our foreign operations, we did not properly allocate taxes to CTA. As a result, we should have allocated additional income tax amounts to CTA in 2003 and 2004 in our discontinued Canadian exploration and production operations and on investments in Korea and Australia. These allocated amounts then impacted losses recorded on the sale of our Canadian operations and our Australian investment in 2004.

The overall impact of these adjustments for CTA and their related tax impact was a $1 million reduction in our net loss in 2004. In 2003, the overall impact of these adjustments was a reduction in our net loss of $45 million. The income effects in both years impacted the results of both continuing and discontinued operations. As of December 31, 2004, the effect of these adjustments to total stockholders equity was a $1 million decrease, resulting from a decrease in accumulated deficit of $46 million and a decrease in accumulated other comprehensive income of $47 million.

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Below are the effects of the restatements related to income taxes and CTA on our income statements, balance sheets and statements of comprehensive income. We have reflected the effects of these restatements in Notes 3, 5, 6, 7, 10, 21 and 22, on pages F-60, F-66, F-67, F-68, F-71, F-103 and F-108.

	For the Year Ended December 31,				
	2004		2003		
	As Reported	As Restated	As Reported	As Restated[1]	As Further Restated[2]
	(In millions, except per share amounts)				
Income Statement:					
Loss on long-lived assets	$ 1,092	$ 1,108	$ 860	$ 860	$ 860
Operating income	206	190	405	405	405
Earnings from unconsolidated affiliates	559	546	363	363	363
Other income	189	193	203	203	203
Loss before income taxes	(777)	(802)	(1,074)	(1,074)	(1,074)
Income taxes	25	31	(551)	(469)	(479)
Loss from continuing operations	(802)	(833)	(523)	(605)	(595)
Discontinued operations, net of income taxes	(146)	(114)	(1,396)	(1,314)	(1,279)
Net loss	(948)	(947)	(1,928)	(1,928)	(1,883)
Basic and diluted loss per share:					
Loss from continuing operations	$ (1.25)	$ (1.30)	$ (0.87)	$ (1.01)	$ (0.99)
Discontinued operations, net of income taxes	(0.23)	(0.18)	(2.34)	(2.20)	(2.14)
Cumulative effect of accounting changes, net of income taxes			(0.02)	(0.02)	(0.02)
Net loss	$ (1.48)	$ (1.48)	$ (3.23)	$ (3.23)	$ (3.15)
Statement of Comprehensive Income					
Foreign currency translation adjustments	$ 7	$ 11	$ 159	$ 159	$ 108
Other comprehensive income	37	41	246	246	195

(1) Amounts restated reflect the effects of reclassifying deferred income tax benefits from continuing operations to discontinued operations as originally reported in our Form 10-K/ A (Amendment No. 1) filed on April 8, 2005. This restatement is further described on page F-45 under the heading Income Taxes.

(2) Amounts further restated reflect the effects of adjusting CTA and related income taxes on certain of our foreign investments with CTA balances as further described on page F-45 under the heading Cumulative Foreign Currency Translation Adjustments (CTA).

	As of December 31,

	2004		2003	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Balance Sheet:				
Deferred income tax assets, current	$ 418	$ 418	$ 592	$ 593
Deferred income tax liabilities, non-current	1,311	1,312	1,551	1,558
Accumulated deficit	(2,855)	(2,809)	(1,907)	(1,862)
Accumulated other comprehensive income (loss)	48	1	11	(40)
Total stockholders equity	3,439	3,438	4,352	4,346

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Principles of Consolidation

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity s losses and/or returns through our variable interests in that entity. The determination of our ability to control or exert significant influence over an entity and if we are allocated a majority of the entity s losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the policies and decisions of an entity and where we are not allocated a majority of the entity s losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity. See Note 2, on page F-56, for a discussion of our adoption of an accounting standard that impacted our consolidation principles in 2004.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Of our regulated pipelines, TGP, EPNG, SNG, CIG, WIC, CPG and MPC follow the regulatory accounting principles prescribed under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. ANR discontinued the application of SFAS No. 71 in 1996. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, postretirement employee benefit plans, and other costs included in, or expected to be included in, future rates. Effective December 31, 2004, ANR Storage began re-applying the provisions of SFAS No. 71.

We perform an annual review to assess the applicability of the provisions of SFAS No. 71 to our financial statements, the outcome of which could result in the re-application of this accounting in some of our regulated systems or the discontinuance of this accounting in others.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of December 31, 2004, we had $180 million of restricted cash in current assets, and $180 million in other non-current assets. As of December 31, 2003, we had $590 million of restricted cash in current assets and $349 million in other non-current assets. Of the 2003 amounts, $468 million was related to funds escrowed for our Western Energy Settlement discussed in Note 17, on page F-87.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts and notes receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

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Inventory

Our inventory consists of spare parts, natural gas in storage, optic fiber and power turbines. We classify all inventory as current or non-current based on whether it will be sold or used in the normal operating cycle of the assets, to which it relates, which is typically within the next twelve months. We use the average cost method to account for our inventories. We value all inventory at the lower of its cost or market value.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates. The following table presents our property, plant and equipment by type, depreciation method and depreciable lives:

Type	Method	Depreciable Lives (In years)
Regulated interstate systems		
SFAS No. 71	Composite [1]	1-63
Non-SFAS No. 71	Composite [1]	1-64
Non-regulated systems		
Transmission and storage facilities	Straight-line	35
Power facilities	Straight-line	3-30
Gathering and processing systems	Straight-line	3-33
Buildings and improvements	Straight-line	5-40
Office and miscellaneous equipment	Straight-line	1-10

[1] For our regulated interstate systems, we use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our rate settlements to the total cost of the group until its net book value equals its salvage value. We re-evaluate depreciation rates each time we redevelop our transportation rates when we file with the FERC for an increase or decrease in rates.

When we retire regulated property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost to remove, sell or dispose, less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income.

We capitalize a carrying cost on funds related to our construction of long-lived assets. This carrying cost consists of (i) an interest cost on our debt that could be attributed to the assets, which applies to all of our regulated transmission businesses and (ii) a return on our equity, that could be attributed to the assets, which only applies to regulated transmission businesses that apply SFAS No. 71. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized during the years ended December 31, 2004, 2003 and 2002, were $39 million, $31 million and $28 million. These amounts are included as a reduction of interest expense in our income statements. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized during the years ended December 31, 2004, 2003 and 2002 were $22 million, $19 million and $8 million. These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity-financed construction are reflected as an increase in the cost of the asset on our balance sheet.

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Asset and Investment Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* and Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock,* to account for asset and investment impairments. Under these standards, we evaluate an asset or investment for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset s ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investment in unconsolidated affiliates. If an impairment is indicated or if we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors. We also reclassify the asset or assets as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have any continuing involvement in the cash flows of those assets after they are sold.

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. This method differs from the successful efforts method of accounting for these activities. The primary differences between these two methods are the treatment of exploratory dry hole costs. These costs are generally expensed under successful efforts when the determination is made that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is then periodically assessed for recoverability as discussed below.

We amortize capitalized costs using the unit of production method over the life of our proved reserves. Capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in the amortizable base. Beginning January 1, 2003, we began capitalizing asset retirement costs associated with proved developed natural gas and oil reserves into our full cost pool, pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations* as discussed below.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices 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. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

When we sell or convey interests (including net profits interests) in our natural gas and oil properties, we reduce our reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of our natural gas and oil properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves. We treat sales proceeds on non-significant sales as an adjustment to the cost of our properties.

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Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. We apply SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* to account for these intangibles. Under these standards, goodwill and intangibles that have indefinite lives are not amortized, but instead are periodically tested for impairment, at least annually, and whenever an event occurs that indicates that an impairment may have occurred. We amortize all other intangible assets on a straight-line basis over their estimated useful lives.

The net carrying amounts of our goodwill as of December 31, 2004 and 2003, and the changes in the net carrying amounts of goodwill for the years ended December 31, 2004 and 2003 for each of our segments are as follows:

	Pipelines	Field Services	Power	Corporate & Other	Total
			(In millions)		
Balances as of January 1, 2003	$ 413	$ 483	$ 3	$ 205	$ 1,104
Additions to goodwill			22		22
Impairments of goodwill			(22)	(163)	(185)
Dispositions of goodwill				(42)	(42)
Other changes		(3)			(3)
Balances as of December 31, 2003	413	480	3		896
Impairments of goodwill		(480)			(480)
Other changes			(3)		(3)
Balances as of December 31, 2004	$ 413	$	$	$	$ 413

Our Field Services impairments resulted from the sale of substantially all of its interests in GulfTerra Energy Partners, as well as certain processing assets in our Field Services segment, to affiliates of Enterprise Products Partners L.P. As a result of these sales, we determined that the remaining assets in our Field Services segment could not support the goodwill in this segment. See Note 22, on page F-108, for a further discussion of the Enterprise transactions.

Our Power segment recorded $22 million of goodwill in May 2003 in connection with the acquisition of Chaparral. In December 2003, we determined that we would sell substantially all of Chaparral s power plants and, based on the bids received, we determined that this goodwill was not recoverable and we fully impaired this amount.

Our Corporate and Other impairments resulted from weak industry conditions in our telecommunications operations. We also disposed of $42 million of goodwill related to our financial services businesses in 2003, which we had previously impaired by $44 million in 2002 based on weak industry conditions and our decision not to invest further capital in those businesses.

In addition to our goodwill, we had a $181 million intangible asset as of December 31, 2003, related to our excess investment in our general partnership interest in GulfTerra. We disposed of this asset as a part of the Enterprise sales described above. We also had other intangible assets of $15 million and $5 million as of December 31, 2004 and 2003, primarily related to customer lists and other miscellaneous intangible assets.

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense related to these plans in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee s salary, the level of benefits provided under the plan,

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actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

We compare the benefits earned, or the accumulated benefit obligation, to the plan s fair value of assets on an annual basis. To the extent the plan s accumulated benefit obligation exceeds the fair value of plan assets, we record a minimum pension liability in our balance sheet equal to the difference in these two amounts. We do not record an additional minimum liability if it is less than the liability already accrued for the plan. If this difference is greater than the pension liability recorded on our balance sheet, however, we record an additional liability and an amount to other comprehensive loss, net of income taxes, on our financial statements.

In 2004, we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $49 million, which is deferred as an actuarial gain in our postretirement benefit liabilities as of December 31, 2004. We expect that the adoption of this guidance will reduce our postretirement benefit expense by approximately $6 million in 2005.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. Our revenue recognition policies by segment are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services. We also derive revenue from sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity over the contract period regardless of the amount that is actually used. For interruptible or volumetric based services and for revenues under natural gas sales contracts, we record revenues when we complete the delivery of natural gas to the agreed upon delivery point and when natural gas is injected or withdrawn from the storage facility. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract or tariff. We are subject to FERC regulations and, as a result, revenues we collect may be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We establish reserves for these potential refunds.

Production revenues. Our Production segment derives revenues primarily through the physical sale of natural gas, oil, condensate and natural gas liquids. Revenues from sales of these products are recorded upon the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. When actual natural gas sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. Costs associated with the transportation and delivery of production are included in cost of sales.

Field Services revenues. Our Field Services segment derives revenues primarily from gathering and processing services and through the sale of commodities that are retained from providing these services. There are two general types of services: fee-based and make-whole. For fee-based services we recognize revenues at the time service is rendered based upon the volume of gas gathered, treated or processed at the contracted fee. For make-whole services, our fee consists of retainage of natural gas liquids and other by-products that are a result of processing, and we recognize revenues on these services at the time we sell these products, which generally coincides with when we provide the service.

Power and Marketing and Trading revenues. Our Power and Marketing and Trading segments derive revenues from physical sales of natural gas and power and the management of their derivative contracts. Our derivative transactions are recorded at their fair value, and changes in their fair value are reflected in operating revenues. See a discussion of our income recognition policies on derivatives below under *Price Risk*

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Management Activities. Revenues on physical sales are recognized at the time the commodity is delivered and are based on the volumes delivered and the contractual or market price.

Corporate. Revenue producing activities in our corporate operations primarily consist of revenues from our telecommunications business. We recognize revenues for our metro transport, collocation and cross-connect services in the month that the services are actually used by the customer.

Environmental Costs and Other Contingencies

We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal or regulatory guidelines dictate otherwise. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by the EPA or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage or government sponsored programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

Our price risk management activities consist of the following activities:

- derivatives entered into to hedge the commodity, interest rate and foreign currency exposures primarily on our natural gas and oil production and our long-term debt;

- derivatives related to our power contract restructuring business; and

- derivatives related to our trading activities that we historically entered into with the objective of generating profits from exposure to shifts or changes in market prices.

We account for all derivative instruments under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Under SFAS No. 133, derivatives are reflected in our balance sheet at their fair value as assets and liabilities from price risk management activities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. See Note 10, on page F-71, for a further discussion of our price risk management activities.

Prior to 2002, we also accounted for other non-derivative contracts, such as transportation and storage capacity contracts and physical natural gas inventories and exchanges, that were used in our energy trading business at their fair values under Emerging Issues Task Force (EITF) Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. In 2002, we adopted EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involving Energy Trading and Risk Management Activities*. As a result, we adjusted the carrying value of these non-derivative instruments to zero and now account for them on an accrual basis of accounting. We also adjusted the physical natural gas inventories used in our historical trading business to their cost (which was lower than market) and our physical natural gas exchanges to their expected settlement amounts and reclassified these amounts to inventory and accounts

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receivable and payable on our balance sheet. Upon our adoption of EITF Issue No. 02-3, we recorded a net loss of $343 million ($222 million net of income taxes) as a cumulative effect of an accounting change in our income statement, of which $118 million was the net adjustment to our natural gas inventories and exchanges and $225 million which was the net adjustment for our other non-derivative instruments.

Our income statement treatment of changes in fair value and settlements of derivatives depends on the nature of the derivative instrument. Derivatives used in our hedging activities are reflected as either revenues or expenses in our income statements based on the nature and timing of the hedged transaction. Derivatives related to our power contract restructuring activities are reflected as either revenues (for settlements and changes in the fair values of the power sales contracts) or expenses (for settlements and changes in the fair values of the power supply agreements). The income statement presentation of our derivative contracts used in our historical energy trading activities is reported in revenue on a net basis (revenues net of the expenses of the physically settled purchases).

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables and payables in our balance sheet.

During 2002, we also adopted Derivatives Implementation Group (DIG) Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed-price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one of its fuel supply contract upon adoption of these new rules, and we recorded our proportionate share of this gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement.

Income Taxes

We record current income taxes based on our current taxable income, and we provide for deferred income taxes to reflect estimated future tax payments and receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

We maintain a tax accrual policy to record both regular and alternative minimum taxes for companies included in our consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. We pay all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, we may bill or refund our subsidiaries for their portion of these income tax payments.

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. These gains and losses were insignificant in 2004, 2003 and 2002. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component of other expense. For the years ended December 31, 2004, 2003 and 2002, we recorded net foreign currency losses of $13 million, $100 million and $91 million primarily

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related to currency losses on our Euro-denominated debt. The U.S. dollar is the functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and the translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholders equity. The net cumulative currency translation gain (loss) recorded in accumulated other comprehensive income was $5 million and $(6) million at December 31, 2004 and 2003. Revenues and expenses are translated at average exchange rates prevailing during the year.

Treasury Stock

We account for treasury stock using the cost method and report it in our balance sheet as a reduction to stockholders equity. Treasury stock sold or issued is valued on a first-in, first-out basis. Included in treasury stock at both December 31, 2004, and 2003, were approximately 1.6 million shares and 1.7 million shares of common stock held in a trust under our deferred compensation programs.

Stock-Based Compensation

We account for our stock-based compensation plans using the intrinsic value method under the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. We have both fixed and variable compensation plans, and we account for these plans using fixed and variable accounting as appropriate. Compensation expense for variable plans, including restricted stock grants, is measured using the market price of the stock on the date the number of shares in the grant becomes determinable. This measured expense is amortized into income over the period of service in which the grant is earned. Our stock options are granted under a fixed plan at the market value on the date of grant. Accordingly, no compensation expense is recognized. Had we accounted for our stock-based compensation using SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the income (loss) and per share impacts on our financial statements would have been different. The following shows the impact on net loss and loss per share had we applied SFAS No. 123:

	Year Ended December 31,		
	2004 (Restated)	2003 (Restated)	2002 (Restated)
	(In millions, except per common share amounts)		
Net loss, as reported	$ (947)	$ (1,883)	$ (1,875)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	14	38	47
Deduct: Total stock-based employee compensation determined under fair value-based method for all awards, net of taxes	(35)	(88)	(169)
Pro forma net loss	$ (968)	$ (1,933)	$ (1,997)
Loss per share:			
Basic and diluted, as reported	$ (1.48)	$ (3.15)	$ (3.35)
Basic and diluted, pro forma	$ (1.51)	$ (3.24)	$ (3.57)

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, which requires that we record a liability for retirement and removal costs of long-lived assets used in our business. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times, generally over the next fifteen years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells.

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In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates, projected inflation rates, and the estimated timing and amounts of settling our obligations, which are based on internal models and external quotes. The following is a summary of our asset retirement liabilities and the significant assumptions we used at December 31:

	2004	2003
	(In millions, except for rates)	
Current asset retirement liability	$ 28	$ 26
Non-current asset retirement liability[1]	$ 244	$ 192
Discount rates	6-8%	8- 10%
Inflation rates	2.5%	2.5%

[1] We estimate that approximately 61 percent of our non-current asset retirement liability as of December 31, 2004 will be settled in the next five years.

Our asset retirement liabilities are recorded at their estimated fair value utilizing the assumptions above, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $9 million, net of income taxes, related to our adoption of SFAS No. 143.

The net asset retirement liability as of December 31, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the year ended December 31, were as follows (in millions):

	2004	2003
Net asset retirement liability at January 1	$ 218	$ 209
Liabilities settled	(34)	(39)
Accretion expense	24	22
Liabilities incurred	34	13
Changes in estimate	30	13
Net asset retirement liability at December 31	$ 272	$ 218

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our aggregate current and non-current retirement liabilities on that date would have been approximately $187 million and our income from continuing operations and net income for the year ended December 31, 2002 would have been lower by $15 million. Basic and diluted earnings per share for the year ended December 31, 2002 would not have been materially affected.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the

classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. On July 1, 2003, we adopted the provisions of SFAS No. 150, and reclassified $625 million of our Capital Trust I and Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement. These dividends were $40 million in both 2004 and 2003. These dividends were recorded in interest and debt expense in 2004,

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and $20 million of our 2003 dividends were recorded in interest expense and $20 million were recorded as distributions on preferred interests in our income statement in 2003.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2004, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95.* This standard requires that companies measure and record the fair value of their stock based compensation awards at fair value on the date they are granted to employees. This fair value is determined based on a variety of assumptions, including volatility rates, forfeiture rates and the option pricing model used (e.g. binomial or Black Scholes). These assumptions could significantly differ from those we currently utilize in determining the proforma compensation expense included in our disclosures required under SFAS No. 123. This standard will also impact the manner in which we recognize the income tax impacts of our stock compensation programs in our financial statements. This standard is effective for interim periods beginning after June 15, 2005, at which time companies can select whether they will apply the standard retroactively by restating their historical financial statements or prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We will adopt this pronouncement in the third quarter of 2005 and are currently evaluating its impact on our consolidated financial statements.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

2. Acquisitions and Consolidations

Acquisitions

During 2003, we acquired the remaining third party interests in our Chaparral and Gemstone investments and began consolidating them in the first and second quarters of 2003, respectively. We historically accounted for these investments using the equity method of accounting. Each of these acquisitions is discussed below.

Chaparral. We entered into our Chaparral investment in 1999 to expand our domestic power generation business. Chaparral owned or had interests in 34 power plants in the United States that have a total generating capacity of 3,470 megawatts (based on Chaparral s interest in the plants). These plants were primarily concentrated in the Northeastern and Western United States. Chaparral also owned several companies that own long-term derivative power agreements.

At December 31, 2002, we owned 20 percent of Chaparral and the remaining 80 percent was owned by Limestone Electron Trust (Limestone). During 2003, we paid $1,175 million to acquire Limestone s 80 percent interest in Chaparral. Limestone used $1 billion of these proceeds to retire notes that were previously guaranteed by us. We have reflected Chaparral s results of operations in our income statement as though we acquired it on January 1, 2003. Had we acquired Chaparral effective January 1, 2002, the net

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increases (decreases) to our income statement for the year ended December 31, 2002, would have been as follows (in millions):

		(Unaudited)
Revenues	$	223
Operating income		(119)
Net income		19
Basic and diluted earnings per share	$	0.03

During the first quarter of 2003, we recorded an impairment of our investment in Chaparral of $207 million before income taxes as further discussed in Note 22, on page F-108.

The following table presents our allocation of the purchase price of Chaparral to its assets and liabilities prior to its consolidation and prior to the elimination of intercompany transactions. This allocation reflects the allocation of (i) our purchase price of $1,175 million; (ii) the carrying value of our initial investment of $252 million; and (iii) the impairment of $207 million (in millions):

Total assets		
Current assets	$	312
Assets from price risk management activities, current		190
Investments in unconsolidated affiliates		1,366
Property, plant and equipment, net		519
Assets from price risk management activities, non-current		1,089
Goodwill		22
Other assets		467
Total assets		3,965
Total liabilities		
Current liabilities		908
Liabilities from price risk management activities, current		19
Long-term debt, less current maturities[(1)]		1,433
Liabilities from price risk management activities, non-current		34
Other liabilities		351
Total liabilities		2,745
Net assets	$	1,220

(1) This debt is recourse only to the project, contract or plant to which it relates.

Our allocation of the purchase price was based on valuations performed by an independent third party consultant, which were finalized in December 2003 with no significant changes to the initial purchase price allocation. These valuations were derived using discounted cash flow analyses and other valuation methods. These valuations indicated that the fair value of the net assets purchased from Chaparral was less than the purchase price we paid for Chaparral by $22 million, which we recorded as goodwill in our financial statements. See Note 1, on page F-44, for a discussion of the subsequent impairment of this goodwill.

Gemstone. We entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. Gemstone had investments in three power projects (Macae, Porto Velho and Araucaria) and also owned a preferred interest in two of our consolidated power projects, Rio Negro and Manaus. In 2003, we acquired the third-party investor s (Rabobank) interest in Gemstone for approximately $50 million. Gemstone s results of operations have been included in our consolidated financial statements since April 1, 2003. Had we acquired Gemstone effective January 1, 2003, our net income and basic and diluted earnings per share for the year ended December 31, 2003 would not have been affected, but our revenues and operating income would have been higher by $58 million and $41 million (amounts unaudited). Had the acquisition been effective January 1, 2002, our 2002 net income and our basic and diluted earnings per share

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would not have been affected, but our revenues and operating income would have been higher by $187 million and $134 million (amounts unaudited).

Our allocation of the purchase price to the assets acquired and liabilities assumed upon our consolidation of Gemstone was as follows (in millions):

Fair value of assets acquired		
Note and interest receivable	$	122
Investments in unconsolidated affiliates		892
Other assets		3
Total assets		1,017
Fair value of liabilities assumed		
Note and interest payable		967
Total liabilities		967
Net assets acquired	$	50

Our allocation of the purchase price was based on valuations performed by an independent third party consultant, which were finalized in December 2003 with no significant changes to the initial purchase price allocation. These valuations were derived using discounted cash flow analyses and other valuation methods.

Prior to our acquisitions of Chaparral and Gemstone, we had other balances, including loans and notes with Chaparral and Gemstone, which were eliminated upon consolidation. As a result, the overall impact on our consolidated balance sheet from acquiring these investments was different than the individual assets and liabilities acquired. The overall impact of these acquisitions on our consolidated balance sheet was an increase in our consolidated assets of $2.1 billion, an increase in our consolidated liabilities of approximately $2.4 billion (including an increase in our consolidated debt of approximately $2.2 billion) and a reduction of our preferred interests in consolidated subsidiaries of approximately $0.3 billion.

Consolidations

Variable Interest Entities. In 2003, the FASB issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity s losses or returns, including fees paid by the entity.

On January 1, 2004, we adopted this standard. Upon adoption, we consolidated Blue Lake Gas Storage Company and several other minor entities and deconsolidated a previously consolidated entity, EMA Power Kft. The overall impact of these actions is described in the following table:

	Increase/(Decrease)
	(In millions)
Restricted cash	$ 34
Accounts and notes receivable from affiliates	(54)
Investments in unconsolidated affiliates	(5)
Property, plant, and equipment, net	37
Other current and non-current assets	(15)

Long-term financing obligations	15
Other current and non-current liabilities	(4)
Minority interest of consolidated subsidiaries	(14)

Blue Lake Gas Storage owns and operates a 47 Bcf gas storage facility in Michigan. One of our subsidiaries operates the natural gas storage facility and we inject and withdraw all natural gas stored in the facility. We own a 75 percent equity interest in Blue Lake. This entity has $8 million of third party debt as of

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December 31, 2004 that is non-recourse to us. We consolidated Blue Lake because we are allocated a majority of Blue Lake s losses and returns through our equity interest in Blue Lake.

EMA Power Kft owns and operates a 69 gross MW dual-fuel-fired power facility located in Hungary. We own a 50 percent equity interest in EMA. Our equity partner has a 50 percent interest in EMA, supplies all of the fuel consumed and purchases all of the power generated by the facility. Our exposure to this entity is limited to our equity interest in EMA, which was approximately $43 million as of December 31, 2004. We deconsolidated EMA because our equity partner is allocated a majority of EMA s losses and returns through its equity interest and its fuel supply and power purchase agreements with EMA.

We have significant interests in a number of other variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of December 31, 2004, these entities consisted primarily of 20 equity and cost investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 7,300 gross MW. We operate many of these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. The long-term debt issued by these entities is recourse only to the power project. As a result, our exposure to these entities is limited to our equity investments in and advances to the entities ($1.1 billion as of December 31, 2004) and our guarantees and other agreements associated with these entities (a maximum of $80 million as of December 31, 2004).

During our adoption of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity s two 274 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $27 million to $32 million per year related to its power plants. The following is a summary of the financial statement impacts of our transactions with this entity for the year ended December 31, 2004 and 2003, and as of December 31, 2004 and December 31, 2003:

	2004	2003
	(In millions)	
Operating revenues	$ (36)	$ 75
Current liabilities from price risk management activities	(20)	(28)
Non-current liabilities from price risk management activities	(29)	(6)

As of December 31, 2004, our financial statements included two consolidated entities that own a 238 MW power facility and a 158 MW power facility in Manaus, Brazil. In January 2005, we entered into agreements with Manaus Energia, under which Manaus Energia will supply substantially all of the fuel consumed and will purchase all of the power generated by the projects through January 2008, at which time Manaus Energia will assume ownership of the plants. We deconsolidated these two entities in January 2005 because Manaus Energia will assume ownership of the plants and since they will absorb a majority of the potential losses of the entities under the new agreements. The impact of this deconsolidation will be an increase in investments in unconsolidated affiliates of $103 million, a decrease in property, plant and equipment of $74 million and a net decrease in other assets and liabilities of $29 million in the first quarter of 2005.

Lakeside. In 2003, we amended an operating lease agreement at our Lakeside Technology Center to add a guarantee benefiting the party who had invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under our previous $3 billion revolving credit facility. This guarantee reduced the investor s risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor. The consolidation of Lakeside Technology Center resulted in an increase in our property, plant and equipment of approximately $275 million and an increase in our long-term debt of approximately $275 million. In 2004, we repaid the $275 million that was scheduled to mature in 2006. Additionally, upon its

consolidation, we recorded an asset impairment charge of

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approximately $127 million representing the difference between the facility s estimated fair value and the residual value guarantee under the lease. Prior to its consolidation, this difference was being periodically expensed as part of operating lease expense over the term of the lease.

Clydesdale. In 2003, we modified our Clydesdale financing arrangement to convert a third-party investor s (Mustang Investors, L.L.C.) preferred ownership interest in one of our consolidated subsidiaries into a term loan that matures in equal quarterly installments through 2005. We also acquired a $10 million preferred interest in Mustang and guaranteed all of Mustang s equity holder s obligations. As a result, we consolidated Mustang which increased our long-term debt by $743 million and decreased our preferred interests of consolidated subsidiaries by $753 million. The $10 million preferred interest we acquired in Mustang was eliminated upon its consolidation. In December 2003, we repaid the remaining Clydesdale debt obligation (see Notes 15 and 16, on pages F-79 and F-86).

3. Divestitures

Sales of Assets and Investments

During 2004, 2003 and 2002, we completed and announced the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	2004	2003	2002
		(In millions)	
Regulated			
Pipelines	$ 59	$ 145	$ 303
Non-regulated			
Production	24	673	1,248
Power	884	768	90
Field Services	1,029	753	1,513
Other			
Corporate	16	149	
Total continuing[1]	2,012	2,488	3,154
Discontinued	1,295	808	177
Total	$ 3,307	$ 3,296	$ 3,331

[1] Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $85 million, $30 million, and $25 million for the years ended December 31, 2004, 2003 and 2002. Proceeds also exclude any non-cash consideration received in these sales, such as the receipt of $350 million of Series C units in GulfTerra from the sale of assets in our Field Services segment in 2002.

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The following table summarizes the significant assets sold:

	2004	2003	2002
Pipelines	Australian pipelines Interest in gathering systems	2.1% interest in Alliance pipeline Equity interest in Portland Natural Gas Transmission System Horsham pipeline in Australia	Natural gas and oil properties located in TX, KS, and OK 12.3% equity interest in Alliance pipeline Typhoon natural gas pipeline
Production	Brazilian exploration and production acreage	Natural gas and oil properties in NM, TX, LA, OK and the Gulf of Mexico	Natural gas and oil properties located in TX, CO and Utah
Power	Utility Contract Funding 31 domestic power plants and several turbines	Interest in CE Generation L.L.C. Mt. Carmel power plant CAPSA/CAPEX investments East Coast Power	40% equity interest in Samalayuca Power II power project in Mexico
Field Services	Remaining general partnership interest, common units and Series C units in GulfTerra South TX processing plants Dauphin Island and Mobile Bay investments	Gathering systems located in WY Midstream assets in the north LA and Mid-Continent regions Common and Series B preference units in GulfTerra 50% of GulfTerra General Partnership	TX & NM midstream assets Dragon Trail gas processing plant San Juan basin gathering, treating and processing assets Gathering facilities in Utah
Corporate	Aircraft	Aircraft Enerplus Global Energy Management Company and its financial operations EnCap funds management business and its investments	None
Discontinued	Natural gas and oil production properties in Canada and other international production assets Aruba and Eagle Point refineries and other petroleum assets	Corpus Christi refinery Florida petroleum terminals Louisiana lease crude Coal reserves Canadian natural gas and oil properties Asphalt facilities	Coal reserves and properties and petroleum assets Natural gas and oil properties located in Western Canada

See Note 5, on page F-66, for a discussion of gains, losses and asset impairments related to the sales above.

During 2005, we have either completed or announced the following sales:

Remaining 9.9% membership interest in the general partner of Enterprise and approximately 13.5 million units in Enterprise for $425 million;

Interests in Cedar Brakes I and II for $94 million;

Interest in a paraxylene plant for $74 million;

Interest in a natural gas gathering system and processing facility for $75 million;

Pipeline facilities for $31 million;

Interest in an Indian power plant for $20 million;

MTBE processing facility for $5 million;

Eagle Point power facility for $3 million; and

Interest in the Rensselaer power facility and its obligations.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. These assets consist of certain of our domestic power plants and natural gas gathering and processing assets in our Field Services segment. As of December 31, 2004, we had assets held for sale of $75 million related to our Indian Springs natural gas gathering and processing facility, which was sold in January 2005, and four domestic power assets, which were impaired in previous years and which we expect to sell within the next

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twelve months. The following table details the items which are reflected as current assets and liabilities held for sale in our balance sheet as of December 31, 2003 (in millions).

Assets Held for Sale		
Current assets	$	46
Investments in unconsolidated affiliates		480
Property, plant and equipment, net		477
Other assets		136
Total assets	$	1,139
Current liabilities	$	54
Long-term debt, less current maturities		169
Other liabilities		13
Total liabilities	$	236

Discontinued Operations

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During 2004, we recognized approximately $22 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties by mid-2005.

Petroleum Markets. During 2003, the sales of our petroleum markets businesses and operations were approved. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax impairment charges during 2003 of approximately $1.5 billion related to these assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately $59 million in 2003 from the sale of our Corpus Christi refinery, our asphalt assets and our Florida terminalling and marine assets.

In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million and used a portion of the proceeds to repay $370 million of debt associated with the Aruba refinery. We recorded realized losses of approximately $32 million in 2004, primarily from the sale of our Aruba and Eagle Point refineries. In addition, in 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing operations in our financial statements based on our decision to retain these operations. Our financial statements for all periods presented reflect this change.

Coal Mining. In 2002, our Board of Directors authorized the sale of our coal mining operations and we recorded an impairment of $185 million. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. The sale of these operations was completed in 2003 for $92 million in cash and $24 million in notes receivable, which were settled in the second quarter of 2004. We did not record a significant gain or loss on these sales.

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The petroleum markets, coal mining and our other international natural gas and oil production operations discussed above, are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of December 31, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
		(In millions)		
Operating Results Data				
Year Ended December 31, 2004 (Restated)[1]				
Revenues	$ 787	$ 31	$	$ 818
Costs and expenses	(839)	(53)		(892)
Loss on long-lived assets	(36)	(22)		(58)
Other income	15			15
Interest and debt expense	(3)	1		(2)
Loss before income taxes	(76)	(43)		(119)
Income taxes	2	(7)		(5)
Loss from discontinued operations, net of income taxes	$ (78)	$ (36)	$	$ (114)
Year Ended December 31, 2003 (Restated)[1]				
Revenues	$ 5,652	$ 88	$ 27	$ 5,767
Costs and expenses	(5,793)	(129)	(13)	(5,935)
Loss on long-lived assets	(1,404)	(89)	(9)	(1,502)
Other income	(10)		1	(9)
Interest and debt expense	(11)	4		(7)
Gain (loss) before income taxes	(1,566)	(126)	6	(1,686)
Income taxes	(262)	(150)	5	(407)
Gain (loss) from discontinued operations, net of income taxes	$ (1,304)	$ 24	$ 1	$ (1,279)
Year Ended December 31, 2002				
Revenues	$ 4,788	$ 71	$ 309	$ 5,168
Costs and expenses	(4,916)	(172)	(327)	(5,415)
Loss on long-lived assets	(97)	(4)	(184)	(285)
Other income	20		5	25
Interest and debt expense	(12)	4		(8)

Loss before income taxes	(217)	(101)	(197)	(515)
Income taxes	16	(33)	(73)	(90)
Loss from discontinued operations, net of income taxes	$ (233)	$ (68)	$ (124)	$ (425)

(1) For 2004, amounts related to Petroleum Markets and Canadian Natural Gas and Oil Production Operations were restated. For 2003, amounts related to Canadian Natural Gas and Oil Production Operations were restated. See Note 1, on page F-44, to the consolidated financial statements for a further discussion of the restatements.

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	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Financial Position Data			
December 31, 2004			
Assets of discontinued operations			
Accounts and notes receivable	$ 39	$ 2	$ 41
Inventory	8		8
Other current assets	3	1	4
Property, plant and equipment, net	14	6	20
Other non-current assets	33		33
Total assets	$ 97	$ 9	$ 106
Liabilities of discontinued operations			
Accounts payable	$ 5	$ 1	$ 6
Other current liabilities	3		3
Other non-current liabilities	3		3
Total liabilities	$ 11	$ 1	$ 12
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivable	$ 259	$ 22	$ 281
Inventory	385	3	388
Other current assets	131	8	139
Property, plant and equipment, net	521	399	920
Other non-current assets	70	6	76
Total assets	$ 1,366	$ 438	$ 1,804
Liabilities of discontinued operations			
Accounts payable	$ 172	$ 39	$ 211
Other current liabilities	86		86
Long-term debt	374		374
Other non-current liabilities	26	3	29
Total liabilities	$ 658	$ 42	$ 700

4. Restructuring Costs

As a result of actions taken in 2002, 2003, and 2004, we incurred certain organizational restructuring costs included in operation and maintenance expense. On January 1, 2003, we adopted the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, and recognized restructuring costs applying the provisions of that standard. Prior to this date, we had recognized restructuring costs according to the provisions of EITF Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and*

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Other Costs to Exit an Activity. By segment, our restructuring costs for the years ended December 31, were as follows:

	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate and Other	Total
				(In millions)			
2004							
Employee severance, retention and transition costs	$ 5	$ 14	$ 2	$ 5	$ 1	$ 11	$ 38
Office relocation and consolidation						80	80
	$ 5	$ 14	$ 2	$ 5	$ 1	$ 91	$ 118
2003							
Employee severance, retention and transition costs	$ 2	$ 6	$ 12	$ 5	$ 4	$ 47	$ 76
Contract termination and other costs			4			44	48
	$ 2	$ 6	$ 16	$ 5	$ 4	$ 91	$ 124
2002							
Employee severance, retention and transition costs	$ 1	$	$ 10	$ 14	$ 1	$ 11	$ 37
Transaction costs						40	40
	$ 1	$	$ 10	$ 14	$ 1	$ 51	$ 77

During the period from 2002 to 2004, we incurred substantial restructuring charges as part of our ongoing liquidity enhancement and cost reduction efforts. Below is a summary of these costs:

Employee severance, retention, and transition costs. During 2002, 2003, and 2004, we incurred employee severance costs, which included severance payments and costs for pension benefits settled under existing benefit plans. During this period, we eliminated approximately 1,900 full-time positions from our continuing business and approximately 1,200 positions related to businesses we discontinued in 2004, 900 full-time positions from our continuing businesses and approximately 1,800 positions related to businesses we discontinued in 2003, and 900 full-time positions through terminations in 2002. As of December 31, 2004, all but $15 million of the total employee severance, retention and transition costs had been paid.

Office relocation and consolidation. In May 2004, we announced that we would begin consolidating our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004, we had established an accrual totaling $80 million to record the discounted liability, net of estimated sub-lease rentals, for our obligations under our existing lease terms. These leases expire at various times through 2014. Of the approximate 888,000 square feet of office space that we lease, we have vacated approximately 741,000 square feet as of December 31, 2004. In addition, we have subleased approximately 238,000 square feet of this space in the third and fourth quarters of 2004. Actual moving expenses related to the relocation were insignificant and were expensed in the period that they were incurred. All amounts related to the relocation are expensed in our corporate operations.

Other. In 2003, our contract termination and other costs included charges of approximately $44 million related to amounts paid for canceling or restructuring our obligations to transport LNG from supply areas to domestic and international market centers. In 2002, we incurred and paid fees of $40 million to eliminate stock price and credit rating triggers related to our Chaparral and Gemstone investments.

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5. Loss on Long-Lived Assets

Loss on long-lived assets from continuing operations consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets including goodwill and other intangibles. During each of the three years ended December 31, our losses on long-lived assets were as follows:

	2004 (Restated)	2003	2002 (Restated)
		(In millions)	
Net realized (gain) loss	$ (16)	$ 69	$ (259)
Asset impairments			
Power			
Domestic assets and restructured power contract entities	397	147	
International assets	213		
Turbines	1	33	162
Field Services			
South Texas processing assets		167	
North Louisiana gathering facility			66
Indian Springs processing assets	13		
Goodwill impairment	480		
Other	11	4	
Production			
Other	8	10	
Corporate			
Telecommunications assets		396	168
Other	1	34	44
Total asset impairments	1,124	791	440
Loss on long-lived assets	1,108	860	181
(Gain) loss on investments in unconsolidated affiliates [1]	(124)	176	612
Loss on assets and investments	$ 984	$ 1,036	$ 793

[1] See Note 22, on page F-108, for a further description of these gains and losses.

Net Realized (Gain) Loss

Our 2004 net realized gain was primarily related to $10 million of gains in our Power segment and $8 million of gains in our Corporate operations from the disposition of assets offset by the $11 million loss on the sale of our South Texas assets in our Field Services segment.

Our 2003 net realized loss was primarily related to a $74 million loss on an agreement to reimburse GulfTerra for a portion of future pipeline integrity costs on previously sold assets. We reduced this accrual by $9 million in 2004 (see Note 22, on page F-108). We also recorded a $67 million gain on the release of our purchase obligation for the Chaco facility and a $14 million gain on the sale of our north Louisiana and Mid-Continent midstream assets in our Field Services segment as well as a $75 million loss on and the termination of our Energy Bridge contracts in the Corporate and other segment and a $10 million loss on the sale of Mohawk River Funding I in our Power segment.

Our 2002 net realized gain was primarily related to $245 million of net gains on the sales of our San Juan gathering assets, our Natural Buttes and Ouray gathering systems, our Dragon Trail gas processing plant and our Texas and New Mexico assets in our Field Services segment. See Note 3, on page F-60, for a further discussion of these divestitures.

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Asset Impairments

Our impairment charges for the years ended December 31, 2004, 2003 and 2002, were recorded primarily in connection with our intent to dispose of, or reduce our involvement in, a number of assets.

Our 2004 Power segment charges include a $227 million impairment on the sale of our domestic equity interests in Cedar Brakes I and II, which closed in the first quarter of 2005, a $183 million impairment of our Manaus and Rio Negro power facilities in Brazil as a result of renegotiating and extending their power purchase agreements, and a $30 million impairment on our consolidated Asian assets in connection with our decision to sell these assets. In addition, in 2004, we impaired UCF prior to its sale by $98 million and recorded impairments of $73 million related to the sales of various other power assets and turbines. Our 2003 and 2002 Power segment impairment charges were primarily a result of our planned sale of domestic power assets (including our turbines classified in long-term assets).

Our Field Services charges include a $480 million impairment of the goodwill associated with the Enterprise sale in 2004 on which we realized an offsetting pretax gain of $507 million recorded in earnings from unconsolidated affiliates, a $24 million impairment on the sales or abandonment of assets in 2004, an impairment of our south Texas processing facilities of $167 million in 2003 based on our planned sale of these facilities to Enterprise (see Note 22, on page F-108), and a $66 million impairment that resulted from our decision to sell our north Louisiana gathering facilities in 2002.

Our corporate telecommunications charge includes an impairment of our investment in the wholesale metropolitan transport services, primarily in Texas, of $269 million in 2003 (including a writedown of goodwill of $163 million) and a 2003 impairment of our Lakeside Technology Center facility of $127 million based on an estimate of what the asset could be sold for in the current market. In 2002, we incurred $168 million of corporate telecommunication charges related to the impairment of our long-haul fiber network and right-of-way assets.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 3 and 22 on pages F-60 and F-108. For additional discussion on goodwill and other intangibles, see Note 1, on page F-44.

6. Other Income and Other Expenses

The following are the components of other income and other expenses from continuing operations for each of the three years ended December 31:

	2004 (Restated)	2003	2002
		(In millions)	
Other Income			
Interest income	$ 93	$ 83	$ 84
Allowance for funds used during construction	23	19	7
Development, management and administrative services fees on power projects from affiliates	21	18	21
Re-application of SFAS No. 71 (CIG and WIC)		18	
Net foreign currency gain	13	12	
Favorable resolution of non-operating contingent obligations		9	38
Gain on early extinguishment of debt			21
Other	43	44	26
Total	$ 193	$ 203	$ 197

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	2004 (Restated)	2003	2002
		(In millions)	
Other Expenses			
Net foreign currency losses[1]	$ 26	$ 112	$ 91
Loss on early extinguishment of debt	12	37	
Loss on exchange of equity security units		12	
Impairment of cost basis investment[2]		5	56
Minority interest in consolidated subsidiaries	41	1	58
Other	20	35	34
Total	$ 99	$ 202	$ 239

(1) Amounts in 2004, 2003 and 2002 were primarily related to losses on our Euro-denominated debt.
(2) We impaired our investment in our Costañera power plant in 2002.

7. Income Taxes

The historical financial information in this note has been restated, as further described in Note 1, on page F-44, of the consolidated financial statements.

Our pretax loss from continuing operations is composed of the following for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
U.S.	$ (721)	$ (1,330)	$ (2,282)
Foreign	(81)	256	399
	$ (802)	$ (1,074)	$ (1,883)

The following table reflects the components of income tax expense (benefit) included in loss from continuing operations for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
Current			
Federal	$ (15)	$ 36	$ (15)
State	39	58	27
Foreign	39	41	32
	63	135	44
Deferred			

Federal	(57)	(566)	(679)
State	(5)	(55)	(11)
Foreign	30	7	5
	(32)	(614)	(685)
Total income taxes	$ 31	$ (479)	$ (641)

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Our income taxes, included in loss from continuing operations, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2004	2003	2002
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$ (281)	$ (376)	$ (659)
Increase (decrease)			
Abandonments and sales of foreign investments	14	(53)	
Valuation allowances	18	(57)	44
Foreign income taxed at different rates	152	(21)	6
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(18)	(13)	(18)
Non-deductible dividends on preferred stock of subsidiaries	9	10	10
State income taxes, net of federal income tax effect	5	5	2
Non-conventional fuel tax credits			(11)
Non-deductible goodwill impairments	139	29	
Other	(7)	(3)	(15)
Income taxes	$ 31	$ (479)	$ (641)
Effective tax rate	(4)%	45%	34%

The following are the components of our net deferred tax liability related to continuing operations as of December 31:

	2004	2003
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 2,590	$ 2,112
Investments in unconsolidated affiliates	410	757
Employee benefits and deferred compensation	93	126
Price risk management activities	71	
Regulatory and other assets	163	193
Total deferred tax liability	3,327	3,188
Deferred tax assets		
Net operating loss and tax credit carryovers		
U.S. federal	1,194	814
State	174	146
Foreign	35	18
Western Energy Settlement	144	400
Environmental liability	174	206
Price risk management activities		136
Debt	79	105

Inventory	85	91
Deferred federal tax on deferred state income tax liability	59	75
Allowance for doubtful accounts	99	75
Lease liabilities	53	
Other	388	235
Valuation allowance	(51)	(9)
Total deferred tax asset	2,433	2,292
Net deferred tax liability	$ 894	$ 896

In 2004, Congress proposed but failed to enact legislation which 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 event, our tax

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

Historically, we have not recorded U.S. deferred tax liabilities on book versus tax basis differences in our Asian power investments because it was our historical intent to indefinitely reinvest the earnings from these projects outside the U.S. 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 deferred tax liabilities which, as of December 31, 2004 were $39 million, representing those instances where the book basis in our investments in the Asian power projects exceeded the tax basis. At this time, however, due to uncertainties as to the manner, timing and approval of the sales, we have not recorded deferred tax assets for those instances where the tax basis of our investments exceeded the book basis, except in instances where we believe the realization of the asset is assured. As of December 31, 2004, total deferred tax assets recorded on our Asian investments was $6 million.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. At December 31, 2004, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $534 million. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income other than $8 million included in the deferred tax liability we recorded related to our investment in our Asian power projects.

The tax effects associated with our employees non-qualified dispositions of employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends are included in additional paid-in-capital in our balance sheets.

As of December 31, 2004, we have U.S. federal alternative minimum tax credits of $283 million and state alternative minimum assessment tax credits of $1 million that carryover indefinitely, $1 million of general business credit carryovers for which the carryover periods end at various times in the years 2012 through 2021, capital loss carryovers of $87 million and charitable contributions carryovers of $2 million for which the carryover periods end in 2008. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2004:

	Carryover Period				
	2005	2006-2010	2011-2015	2016-2024	Total
	(In millions)				
U.S. federal net operating loss	$	$ 7	$	$ 3,113	$ 3,120
State net operating loss	8	849	412	987	2,256

We also had $103 million of foreign net operating loss carryovers that carryover indefinitely. Usage of our U.S. federal carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

We record a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2004, we maintained a valuation allowance of $37 million related to state net operating loss carryovers, $7 million related to our estimated ability to realize state tax benefits from the deduction of the charge we took related to the Western Energy Settlement, $5 million related to foreign deferred tax assets for book impairments and ceiling test charges, $1 million related to a general business credit carryover and $1 million related to other carryovers. As of December 31, 2003, we maintained a valuation allowance of $5 million related to state tax

benefits of the Western Energy Settlement, $1 million related to state net operating loss carryovers, $1 million related to foreign deferred tax assets for ceiling test

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charges and $1 million related to a general business credit carryover and $1 million related to other carryovers. The change in our valuation allowances from December 31, 2003 to December 31, 2004 is primarily related to an additional valuation allowance for State of New Jersey legislation that limited use of net operating loss carryovers, an increase in valuation allowances on foreign impairments of assets and an increase in the state valuation allowance related to the Western Energy Settlement.

We are currently under audit by the IRS and other taxing authorities, and our audits are in various stages of completion. The tax years for 1995-2000 are pending with the IRS Appeals Office related to The Coastal Corporation, with which we merged in 2001. We anticipate that the Appeals proceedings for 1995-1997 will be finalized within 12 months, while the other years will take longer to complete. The IRS has completed its examination of El Paso s tax years through 2000. The 2001-2002 tax years are currently under examination, which we anticipate will be completed within 12 months. There may be additional proceedings in the IRS Appeals Office with respect to this examination. We maintain a reserve for tax contingencies that management believes is adequate, and as audits are finalized we will make appropriate adjustments to those estimates.

8. Earnings Per Share

We incurred losses from continuing operations during the three years ended December 31, 2004. Accordingly, we excluded a number of securities for the years ended December 2004, 2003, and 2002, from the determination of diluted earnings per share due to their antidilutive effect on loss per common share. These included stock options, restricted stock, trust preferred securities, equity security units, and convertible debentures. Additionally, in 2003, we excluded shares related to our remaining stock obligation under the Western Energy Settlement (see Note 17, on page F-87, for further information). For a further discussion of these instruments, see Notes 15 and 20, on pages F-79 and F-101.

9. Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31, 2004 and 2003.

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 19,189	$ 19,829	$ 21,724	$ 21,166
Commodity-based price risk management derivatives	68	68	1,406	1,406
Interest rate and foreign currency hedging derivatives	239	239	123	123
Investments	6	6	12	12

As of December 31, 2004 and 2003, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represented fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the interest rate. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. See Note 10, on page F-71, for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

10. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2004 and 2003. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production as well as instruments to hedge our interest rate and currency risks on long-term

debt. Derivatives from power contract restructuring activities relate to power

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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.

	2004	2003
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges[1]	$ (536)	$ (31)
Derivatives from power contract restructuring activities [2]	665	1,925
Other commodity-based derivative contracts[1]	(61)	(488)
Total commodity-based derivatives	68	1,406
Interest rate and foreign currency hedging derivatives	239	123
Net assets from price risk management activities[3]	$ 307	$ 1,529

(1) In December 2004, we designated other commodity-based derivative contracts with a fair value loss of $592 million 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.

(2) Includes derivative contracts with a fair value of $596 million as of December 31, 2004 that we sold in connection with the sale of Cedar Brakes I and II in the first quarter of 2005, and $942 million as of December 31, 2003 that we sold in connection with the sales of UCF and Mohawk River Funding IV in 2004.

(3) Included in both current and non-current assets and liabilities from price risk management activities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. Due to major industry participants exiting or reducing their trading activities in 2002 and 2003, the availability of reliable commodity pricing data from market-based sources that we used in estimating the fair value of our derivatives was significantly limited for certain locations and for longer time periods. Consequently, we now use an independent pricing source for a substantial amount of our forward pricing data beyond the current two-year period. For forward pricing data within two years, we use commodity prices from market-based sources such as the New York Mercantile Exchange. For periods beyond two years, we use a combination of commodity prices from market-based sources and other forecasted settlement prices from an independent pricing source to develop price curves, which we then use to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discount these estimated settlement values using a LIBOR curve, except as described below for our restructured power contracts. Additionally, contracts denominated in foreign currencies are converted to U.S. dollars using market-based, foreign exchange spot rates.

We record valuation adjustments to reflect uncertainties associated with the estimates we use in determining fair value. Common valuation adjustments include those for market liquidity and those for the credit-worthiness of our contractual counterparties. To the extent possible, we use market-based data together with quantitative methods to measure the risks for which we record valuation adjustments and to determine the level of these valuation adjustments.

The above valuation techniques are used for valuing derivative contracts that have historically been accounted for as trading activities, as well as for those that are used to hedge our natural gas and oil production. We have adjusted this method to determine the fair value of our restructured power contracts. Our restructured power derivatives use the same methodology discussed above for determining the forward settlement prices but are discounted using a risk free

interest rate, adjusted for the individual credit spread for each counterparty to the contract. Additionally, no liquidity valuation adjustment is provided on these derivative contracts since they are intended to be held through maturity.

Derivatives Designated as Hedges

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure, which primarily relate to our natural gas and oil production hedges and foreign currency and interest rate risks on our long-term debt, are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability.

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Hedges of fair value exposure are entered into to protect the fair value of a recognized asset, liability or firm commitment. When we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Our hedges of our foreign currency exposure are designated as either cash flow hedges or fair value hedges based on whether the interest on the underlying debt is converted to either a fixed or floating interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income (loss) to the extent that they are effective and are not included in income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge s change in value is recognized immediately in earnings as a component of operating revenues in our income statement. Changes in the fair value of derivatives that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of the related hedged assets, liabilities or firm commitments.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess whether these derivatives are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge or if we decide to discontinue the hedging relationship.

A discussion of each of our hedging activities is as follows:

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets with the objective of realizing a fixed cash flow stream from these activities. We also have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollar. We use currency swaps to convert the fixed amounts of foreign currency due under foreign currency denominated debt to U.S. dollar amounts. As of December 31, 2004 and 2003, we have swaps that convert approximately 275 million of our debt to $255 million, substantially all of which were cancelled with the payoff of the underlying hedged debt in March 2005. A summary of the impacts of our cash flow hedges included in accumulated other comprehensive loss, net of income taxes, as of December 31, 2004 and 2003 follows.

	Accumulated Other Comprehensive Income (Loss)		Estimated Income (Loss) Reclassification in 2005[1]	Final Termination Date
	2004	2003		
Commodity cash flow hedges				
Held by consolidated entities	$ (23)	$ (72)	$ 24	2012
Held by unconsolidated affiliates	(8)	13	4	2006
Total commodity cash flow hedges	(31)	(59)	28	
Foreign currency cash flow hedges				
Fixed rate[2]	81	58	81	2005
Undesignated[3]	(8)	(9)	(4)	2009
Total foreign currency cash flow hedges	73	49	77	
Total[4]	$ 42	$ (10)	$ 105	

(1) Reclassifications occur upon the physical delivery of the hedged commodity and the corresponding expiration of the hedge or if the forecasted transaction is no longer probable.

(2) Substantially all of these amounts were reclassified into income with the repurchase of approximately 528 million of debt in March 2005.

(3) In December 2002, we removed the hedging designation on these derivatives related to our Euro-denominated debt.

(4) Accumulated other comprehensive income (loss) also includes $5 million and $(6) million of net cumulative currency translation adjustments and $(46) million and $(24) million of additional minimum pension liability as of December 31, 2004 and 2003. All amounts are net of taxes.

In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we

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reclassified this amount to derivatives designated as hedges, specifically cash flow hedges, beginning in the fourth quarter of 2004.

For the years ended December 31, 2004, 2003 and 2002, we recognized net losses of $1 million, $2 million and $4 million, net of income taxes, in our loss from continuing operations related to the ineffective portion of all cash flow hedges.

Fair Value Hedges. We have fixed rate U.S. dollar and foreign currency denominated debt that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps to effectively convert the fixed amounts of interest due under the debt agreements to variable interest payments based on LIBOR plus a spread. As of December 31, 2004 and 2003, these derivatives had a net fair value of $117 million and $33 million. Specifically, we had derivatives with fair value losses of $20 million and $19 million as of December 31, 2004 and 2003, that converted the interest rate on $440 million and $350 million of our U.S. dollar denominated debt to a floating weighted average interest rate of LIBOR plus 4.2%. Additionally, we had derivatives with fair values of $137 million and $52 million as of December 31, 2004 and 2003, that converted approximately 450 million and 350 million of our debt to $511 million and $390 million. These derivatives also converted the interest rate on this debt to a floating weighted average interest rate of LIBOR plus 3.9% as of December 31, 2004, and LIBOR plus 3.7% as of December 31, 2003. We have recorded the fair value of those derivatives as a component of long-term debt and the related accrued interest. For the year ended December 31, 2002, the net financial statement impact of our fair value hedges was immaterial.

In March 2005, we repurchased approximately 528 million of debt, of which approximately 100 million were hedged with fair value hedges. As a result of the repurchase, we removed the hedging designation on, and subsequently cancelled, these derivative contracts.

In December 2002, we reduced the volumes of foreign currency exchange risk that we have hedged for our debt, and we removed the hedging designation on derivatives that had a net fair value gain of $3 million and $6 million at December 31, 2004 and 2003. These amounts, which are reflected in long-term debt, will be reclassified to income as the interest and principal on the debt are paid through 2009.

Power Contract Restructuring Activities

During 2001 and 2002, we conducted power contract restructuring activities that involved amending or terminating power purchase contracts at existing power facilities. In a restructuring transaction, we would eliminate the requirement that the plant provide power from its own generation to the customer of the contract (usually a regulated utility) and replace that requirement with a new contract that gave us the ability to provide power to the customer from the wholesale power market. In conjunction with these power restructuring activities, our Marketing and Trading segment generally entered into additional market-based contracts with third parties to provide the power from the wholesale power market, which effectively locked in our margin on the restructured transaction as the difference between the contracted rate in the restructured sales contract and the wholesale market rates on the purchase contract at the time.

Prior to a restructuring, the power plant and its related power purchase contract were accounted for at their historical cost, which was either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to the restructuring were, in most cases, accounted for on an accrual basis as power was generated and sold from the plant.

Following a restructuring, the accounting treatment for the power purchase agreement changed since the restructured contract met the definition of a derivative. In addition, since the power plant no longer had the exclusive obligation to provide power under the original, dedicated power purchase contract, it operated as a peaking merchant facility, generating power only when it was economical to do so. Because of this significant change in its use, the plant s carrying value was typically written down to its estimated fair value. These changes also often required us to terminate or amend any related fuel supply and/or steam agreements, and enter into other third party and intercompany contracts such as transportation agreements, associated with operating the merchant facility. Finally, in many cases power contract restructuring activities also involved

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contract terminations that resulted in cash payments by the customer to cancel the underlying dedicated power contract.

In 2002, we completed a power contract restructuring on our consolidated Eagle Point power facility and applied the accounting described above to that transaction. We also employed the principles of our power contract restructuring business in reaching a settlement of a dispute under our Nejapa power contract which included a cash payment to us. We recorded these payments as operating revenues in our Power segment. We also terminated a power contract at our consolidated Mount Carmel facility in exchange for a $50 million cash payment. For the year ended December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements (in millions):

	Assets from Price Risk Management Activities	Liabilities from Price Risk Management Activities	Property, Plant and Equipment and Intangible Assets	Operating Revenues	Operating Expenses	Increase (Decrease) in Minority Interest[1]
Initial gain on restructured contracts	$ 978	$	$	$ 1,118	$	$ 172
Write-down of power plants and intangibles and other fees			(352)		476	(109)
Change in value of restructured contracts during 2002	8			(96)		(20)
Change in value of third-party wholesale power supply contracts		18		(18)		(3)
Purchase of power under power supply contracts					47	(11)
Sale of power under restructured contracts				111		28
Total	$ 986	$ 18	$ (352)	$ 1,115	$ 523	$ 57

[1] In our restructuring activities, third-party owners also held ownership interests in the plants and were allocated a portion of the income or loss.

As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and are actively seeking to sell or otherwise dispose of our existing restructured power contracts. In 2004, we completed the sales of UCF (which is the restructured Eagle Point power contract) and Mohawk River Funding IV. (See Note 3, on page F-60, for a discussion of these sales.) Mohawk River Funding, III (MRF III) had a prior purchase agreement (USGen PPA) with USGen New England, Inc. (USGen). USGen filed for Chapter 11 bankruptcy protection and the USGen PPA was terminated automatically as a result of the bankruptcy filing. MRF III filed a proof of claim in the bankruptcy case and the bankruptcy court issued an order resolving the claim. The order is not final at this time and may be subject to change which could result in a final award

that is either more or less than the receivable that has been recorded. Additionally, in March 2005, we completed the sale of Cedar Brakes I and II and the related restructured derivative power contracts.

Other Commodity-Based Derivatives

Our other commodity-based derivatives primarily relate to our historical trading activities, which include the services we provide in the energy sector that we entered into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities. Our derivatives in our trading portfolio had a fair value liability of $61 million and $488 million as of December 31, 2004 and 2003. In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million 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.

Credit Risk

We are subject to credit risk related to our financial instrument assets. Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their

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contractual obligations. We measure credit risk as the estimated replacement costs for commodities we would have to purchase or sell in the future, plus amounts owed from counterparties for delivered and unpaid commodities. These exposures are netted where we have a legally enforceable right of setoff. We maintain credit policies with regard to our counterparties in our price risk management activities to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties financial condition (including credit rating), (ii) collateral under certain circumstances (including cash in advance, letters of credit, and guarantees), (iii) the use of margining provisions in standard contracts, and (iv) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

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

The following table presents a summary of our counterparties in which we had net financial instrument asset exposure as of December 31, 2004 and 2003.

	Net Financial Instrument Asset Exposure			
Counterparty	**Investment Grade[1]**	**Below Investment Grade[1]**	**Not Rated[1]**	**Total**
		(In millions)		
December 31, 2004				
Energy marketers	$ 440	$ 44	$ 35	$ 519
Natural gas and electric utilities	424		91	515
Other	245		7	252
Net financial instrument assets [2]	1,109	44	133	1,286
Collateral held by us	(349)	(39)	(81)	(469)
Net exposure from financial instrument assets	$ 760	$ 5	$ 52	$ 817
December 31, 2003				
Energy marketers	$ 425	$ 43	$ 53	$ 521
Natural gas and electric utilities	1,755		78	1,833
Other	106	1	75	182
Net financial instrument assets [2]	2,286	44	206	2,536
Collateral held by us	(132)	(10)	(83)	(225)
	$ 2,154	$ 34	$ 123	$ 2,311

Net exposure from financial instrument assets

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

(2) Net asset exposure from financial instrument assets primarily relates to our assets and liabilities from price risk management activities. These exposures have been prepared by netting assets against liabilities on counterparties where we have a contractual right to offset. The positions netted include both current and non-current amounts and do not include amounts already billed or delivered under the derivative contracts, which would be netted against these exposures.

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We have approximately 125 counterparties, most of which are energy marketers. Although most of our counterparties are not currently rated as below investment grade, if one of our counterparties fails to perform, such as in the case of Enron (see Note 17, on page F-87, for a further discussion of the Enron Bankruptcy), we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and quantities cannot be established.

One electric utility customer, Public Service Electric and Gas Company (PSEG), comprised 42 percent and 66 percent of our net financial instrument asset exposure as of December 31, 2004 and 2003. Our net financial instrument asset exposure to PSEG was eliminated with the sale of our interests in Cedar Brakes I and II in the first quarter of 2005. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

11. Inventory

We have the following current inventory as of December 31:

	2004	2003
	(In millions)	
Materials and supplies and other	$ 130	$ 145
NGL and natural gas in storage	38	36
Total current inventory	$ 168	$ 181

We also have the following non-current inventory that is included in other assets in our balance sheets as of December 31:

	2004	2003
	(In millions)	
Dark fiber	$	$ 5
Turbines	76	98
Total non-current inventory	$ 76	$ 103

12. Regulatory Assets and Liabilities

Our regulatory assets and liabilities are included in other current and non-current assets and liabilities in our balance sheets. These balances are presented in our balance sheets on a gross basis. Below are the details of our regulatory assets and liabilities for our regulated interstate systems that apply the provisions of SFAS No. 71 as of December 31, which are recoverable over various periods:

Description	2004	2003
	(In millions)	
Current regulatory assets[1]	$ 3	$ 2
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction[1]	85	77
Postretirement benefits[1]	30	32

Unamortized net loss on reacquired debt[1]	23	26
Under-collected state income tax[1]	7	4
Other[1]	10	4
Total non-current regulatory assets	155	143
Total regulatory assets	$ 158	$ 145
Current regulatory liabilities		
Cashout imbalance settlement[1]	$ 9	$ 9
Other		2
	9	11

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Description	2004	2003
	(In millions)	
Non-current regulatory liabilities		
Environmental liability[1]	97	87
Cost of removal of offshore assets	50	51
Property and plant depreciation	35	28
Postretirement benefits[1]	13	11
Plant regulatory liability[1]	11	11
Excess deferred income taxes	11	10
Other	11	5
Total non-current regulatory liabilities	228	203
Total regulatory liabilities	$ 237	$ 214

[1] Some of these amounts are not included in our rate base on which we earn a current return.

13. Other Assets and Liabilities

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

	2004	2003
	(In millions)	
Other current assets		
Prepaid expenses	$ 132	$ 146
Other	47	64
Total	$ 179	$ 210
Other non-current assets		
Pension assets (Note 18, page F-97)	$ 933	$ 962
Notes receivable from affiliates	287	349
Restricted cash (Note 1, page F-44)	180	349
Unamortized debt expenses	192	246
Regulatory assets (Note 12, page F-77)	155	143
Long-term receivables	343	108
Notes receivable	46	113
Turbine inventory (Note 11, page F-77)	76	98
Other investments	48	60
Assets of discontinued operations		405
Other	53	163
Total	$ 2,313	$ 2,996

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	2004	2003
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 136	$ 156
Broker margin and other amounts on deposit with us	131	155
Income taxes	80	132
Environmental, legal and rate reserves (Note 17, page F-87)	84	96
Deposits	39	67
Obligations under swap agreement (Note 15, page F-79)		49
Other postretirement benefits (Note 18, page F-97)	38	45
Asset retirement obligations (Note 1, page F-44)	28	26
Dividends payable	25	23
Accrued liabilities	74	49
Other	185	112
Total	$ 820	$ 910
Other non-current liabilities		
Environmental and legal reserves (Note 17, page F-87)	$ 763	$ 450
Other postretirement and employment benefits (Note 18, page F-97)	248	272
Obligations under swap agreement (Note 15, page F-79)		208
Regulatory liabilities (Note 12, page F-77)	228	203
Asset retirement obligations (Note 1, page F-44)	244	192
Other deferred credits	126	157
Accrued lease obligations	157	106
Insurance reserves	125	136
Deferred gain on sale of assets to GulfTerra (Note 17, page F-87)	15	101
Deferred compensation	56	60
Pipeline integrity liability (Note 22, page F-108)	50	69
Liabilities of discontinued operations		3
Other	64	90
Total	$ 2,076	$ 2,047

14. Property, Plant and Equipment

At December 31, 2004 and 2003, we had approximately $0.8 billion and $1.0 billion of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2004 and 2003, TGP, EPNG and ANR have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $5 billion and accumulated depreciation was approximately $1.3 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during the three years ended December 31, 2004, 2003, and 2002 was approximately $76 million, $74 million and $71 million. The adoption of SFAS No. 142 did not impact these amounts since they were included as part of our property, plant and equipment, rather than as goodwill. We do not currently earn a return on these excess purchase costs from our rate payers.

15. Debt, Other Financing Obligations and Other Credit Facilities

	2004	2003
	(In millions)	
Short-term financing obligations, including current maturities	$ 955	$ 1,457
Long-term financing obligations	18,241	20,275
Total	$ 19,196	$ 21,732

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Our debt and other credit facilities consist of both short and long-term borrowings with third parties and notes with our affiliated companies. During 2004, we entered into a new $3 billion credit agreement and sold entities with debt obligations. A summary of our actions is 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 revolving credit facility.
(3) Consists of $815 million of debt related to Utility Contract Funding, L.L.C. and $72 million of debt related to Mohawk River Funding IV.

Short-Term Financing Obligations

We had the following short-term borrowings and other financing obligations as of December 31:

	2004	2003
	(In millions)	
Current maturities of long-term debt and other financing obligations	$948	$ 1,449
Short-term financing obligation	7	8
	$955	$ 1,457

Long-Term Financing Obligations

Our long-term financing obligations outstanding consisted of the following as of December 31:

	2004	2003
	(In millions)	
Long-term debt		
ANR Pipeline Company		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	$ 800	$ 800
Notes, 13.75% due 2010	12	13
Colorado Interstate Gas Company		
Debentures, 6.85% through 10.0%, due 2005 and 2037	280	280
El Paso CGP Company		
Senior notes, 6.2% through 7.75%, due 2004 through 2010	930	1,305
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,357	1,395
El Paso Corporation		
Senior notes, 5.75% through 7.125%, due 2006 through 2009	1,956	1,817
Equity security units, 6.14% due 2007	272	272

Notes, 6.625% through 7.875%, due 2005 through 2018	1,952	2,002
Medium-term notes, 6.95% through 9.25%, due 2004 through 2032	2,784	2,812
Zero coupon convertible debentures due 2021	822	895
$3 billion revolver, LIBOR plus 3.5% due June 2005		850
$1.25 billion term loan, LIBOR plus 2.75% due 2009	1,245	
El Paso Natural Gas Company		
Notes, 7.625% and 8.375%, due 2010 and 2032	655	655
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
El Paso Production Holding Company		
Senior notes, 7.75%, due 2013	1,200	1,200

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	2004	2003
	(In millions)	
Power		
Non-recourse senior notes, 7.75% through 9.875%, due 2008 through 2014	666	770
Non-recourse notes, variable rates, due 2007 and 2008	320	361
Recourse notes, 7.27% and 8.5%, due 2005 and 2016	40	85
Gemstone notes, 7.71% due 2004		950
Non-recourse financing UCF, 7.944%, due 2016		829
Southern Natural Gas Company		
Notes and senior notes, 6.125% through 8.875%, due 2007 through 2032	1,200	1,200
Tennessee Gas Pipeline Company		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
Notes, 8.375%, due 2032	240	240
Other	137	404
	18,714	20,981
Other financing obligations		
Capital Trust I	325	325
Coastal Finance I	300	300
Lakeside Technology Center lease financing loan due 2006		275
	625	900
Subtotal	19,339	21,881
Less:		
Unamortized discount and premium on long-term debt	150	157
Current maturities	948	1,449
Total long-term financing obligations, less current maturities	$ 18,241	$ 20,275

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During 2004 and to date in 2005, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Principal	Due Date
			(In millions)	
Issuances and other increases				
Macae	Non-recourse note	LIBOR + 4.25%	$ 50	2007
Blue Lake Gas Storage[1]	Non-recourse term loan	LIBOR + 1.2%	14	2006
El Paso[2]	Notes	6.50%	213	2005
El Paso[3]	Term loan	LIBOR + 2.75%	1,250	2009
Increases through December 31, 2004			$ 1,527	
Colorado Interstate Gas Company	Senior Notes	5.95%	200	2015
Increases through March 25, 2005			$ 1,727	
Repayments, repurchases and other retirements				
El Paso CGP	Note	LIBOR + 3.5%	$ 200	
El Paso	Revolver	LIBOR + 3.5%	850	
El Paso CGP	Note	6.2%	190	
Mohawk River Funding IV [4]	Non-recourse note	7.75%	72	
Utility Contract Funding [4]	Non-recourse senior notes	7.944%	815	
Gemstone	Notes	7.71%	950	
Lakeside	Note	LIBOR + 3.5%	275	
El Paso CGP	Senior Debentures	10.25%	38	
El Paso[2]	Notes	6.50%	213	
El Paso[5]	Zero coupon debenture		109	
El Paso	Notes	Various	49	
El Paso CGP	Notes	Various	185	
El Paso	Medium-term notes	Various	28	
Other	Long-term debt	Various	283	
Decreases through December 31, 2004			4,257	
El Paso[5]	Zero coupon debenture		185	
Cedar Brakes I[4]	Non-recourse notes	8.5%	286	
Cedar Brakes II[4]	Non-recourse notes	9.88%	380	
El Paso[6]	Euros	5.75%	715	
Other	Long-term debt	Various	96	

Decreases through March 25, 2005	$ 5,919

(1) This debt was consolidated as a result of adopting FIN No. 46 (see Note 2, on page F-56).

(2) In the fourth quarter of 2004, we entered into an agreement with Enron that liquidated two derivative swap agreements of approximately $221 million in exchange for approximately $213 million of 6.5% one year notes. Subsequent to the closing of our new credit agreement, these notes were paid in full.

(3) Proceeds from the $1.25 billion term loan under the new credit agreement entered into in November 2004.

(4) The remaining balance of these debt obligations was eliminated when we sold our interests in Mohawk River Funding IV, UCF and Cedar Brakes I and II.

(5) In December 2004 and January 2005, we repurchased these 4% yield-to-maturity zero-coupon debentures. The amount shown as principal is the carrying value on the date the debt was retired as compared to its maturity value in 2021 of $206 million in December 2004, and $351 million in January 2005.

(6) In March 2005, we repaid debt with a principal balance of 528 million, which had a carrying value of $724 million in long-term debt on our balance sheet as of December 31, 2004. In conjunction with this repayment, we also terminated derivative contracts with a fair value of $152 million as of December 31, 2004 that hedged this debt. The total net payment was $579 million. See Note 10, on page F-71, for additional information on the repurchase of the derivative contracts.

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Aggregate maturities of the principal amounts of long-term financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2005	$	948
2006[1]		1,155
2007		835
2008		733
2009		2,637
Thereafter		13,031
Total long-term financing obligations, including current maturities	$	19,339

[1] Excludes $0.8 billion of zero coupon debentures as discussed below.

Included above in 2005 is $320 million of debt associated with our Macae project in Brazil, as a result of an event of default on Macae s non-recourse debt. (See Note 17, on page F-87, for additional details on the event of default.) Also included in 2005 are approximately $114 million of notes and debentures that holders have the option to redeem in 2005, prior to their stated maturities. Of this amount, $75 million is eligible for redemption solely in 2005 and, if not redeemed, will be reclassified to long-term debt in 2006.

Included in the thereafter line of the table above are $600 million of other debentures that holders have an option to redeem in 2007 prior to their stated maturities and $822 million of zero coupon convertible debentures. The zero-coupon debentures have a maturity value of $1.6 billion, are due 2021 and have a yield to maturity of 4 percent. The holders can cause us to repurchase these debentures at their option in years 2006, 2011 and 2016, should they make this election, we can choose to settle in cash or common stock at a price which approximates market. These debentures are convertible into 7,468,726 shares of our common stock, which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate is equal to a conversion price of $94.604 per share of our common stock.

Credit Facilities

In November 2004, we replaced our previous $3 billion revolving credit facility, which was scheduled to mature in June 2005, with a new $3 billion credit agreement with a group of lenders. This $3 billion credit agreement consists of a $1.25 billion five-year term loan; a $1 billion three-year revolving credit facility; and a $750 million, five-year letter of credit facility. Certain of our subsidiaries, EPNG, TGP, ANR and CIG, also continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement, which is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company and Southern Gas Storage Company.

As of December 31, 2004, we had $1.25 billion outstanding under the term loan and had utilized approximately all of the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to issue letters of credit. The term loan accrues interest at LIBOR plus 2.75 percent, matures in November 2009, and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the new revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. The terms of the new $750 million letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity under the letter of credit facility as revolving loans with a maturity in November 2009. We pay LIBOR plus 2.75 percent on any amounts borrowed under the letter of credit facility, and 2.85 percent on letters of credit and unborrowed funds.

Restrictive Covenants

Our restrictive covenants includes restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these

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covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our new credit agreement the significant debt covenants and cross defaults are:

(a) El Paso s ratio of Debt to Consolidated EBITDA, each as defined in the new credit agreement, shall not exceed 6.50 to 1.0 at any time prior to September 30, 2005, 6.25 to 1.0 at any time on or after September 30, 2005 and prior to June 30, 2006, and 6.00 to 1.0 at any time on or after June 30, 2006 until maturity;

(b) El Paso s ratio of Consolidated EBITDA, as defined in the new credit agreement, to interest expense plus dividends paid shall not be less than 1.60 to 1.0 prior to March 31, 2006, 1.75 to 1.0 on or after March 31, 2006 and prior to March 31, 2007, and 1.80 to 1.0 on or after March 31, 2007 until maturity;

(c) EPNG, TGP, ANR, and CIG cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the new credit agreement, for that particular company to exceed 5 to 1;

(d) the proceeds from the issuance of Debt by our pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt; and

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

In addition to the above restrictions and default provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in our cash management program, and limitations on our ability to prepay debt.

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

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $850 million. If breached, the amounts guaranteed by its guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of such subsidiaries in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

Other Financing Arrangements

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I, a wholly owned subsidiary, which issued 6.5 million of 4.75 percent trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued due 2028, their sole asset. Trust I s sole source of income is interest earned on these debentures. This interest income is used to pay the obligations on Trust I s preferred securities. We provide a full and unconditional guarantee of Trust I s preferred securities.

Trust I s preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 percent, carry a liquidation value of $50 per security plus accrued and unpaid

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distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I preferred security (equivalent to a conversion price of $41.59 per common share). During 2003, the outstanding amounts of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Coastal Finance I. Coastal Finance I is an indirect wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I holds subordinated debt securities issued by our wholly owned subsidiary, El Paso CGP, that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375 percent of the liquidation amount of $25 per preferred security. Coastal Finance I s only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I s preferred securities. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. El Paso CGP provides a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available. We have no obligation to provide funds to Coastal Finance I for the payment of or redemption of the preferred securities outside of our obligation to pay interest and principal on the subordinated debt securities. During 2003, the amounts outstanding of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Equity Security Units. In June 2002, we issued 11.5 million, 9 percent equity security units. Equity security units consist of two securities: i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86 percent and that requires its holder to buy our common stock on a stated settlement date of August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14 percent. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders obligation to purchase shares of our common stock under the purchase contracts. In December 2003, we completed a tender offer to exchange 6,057,953 of the outstanding equity security units, which represented approximately 53 percent of the total units outstanding. In the exchange, we issued a total of 15,182,972 shares of our common stock that had a total market value of $119 million, and paid $59 million in cash.

When the remaining purchase contracts are settled in 2005, the contract provides for us to issue common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 11 million shares and up to a maximum of approximately 14 million shares on the settlement date, depending on our average stock price.

Non-Recourse Project Financings. Many of our power subsidiaries and investments have borrowed a material portion of the costs to acquire or construct their domestic and international power assets. Such borrowings are made with recourse only to the project company and assets (i.e. without recourse to El Paso). On occasion, events have occurred in connection with several of our projects that have either constituted an event of default under the loan agreements or could constitute an event of default upon delivery of a notice from the lenders and the failure of the subsidiary or investee to cure the event during an applicable grace period. Currently, we have one consolidated subsidiary, Macae, where the power off taker to the project, Petrobras, has not paid all amounts owed under its contract with the plant. This non-payment has created an event of default on that project under its loan agreements. Accordingly, we classified approximately $320 million as current debt as of December 31, 2004. (See Note 17, on page F-87, for additional information on our investment in Macae.) In addition, we have several other projects that we account for as equity investments that are in default under their loan agreements, including Saba, Berkshire and East Asia Power. We have written off all of our investment in both the Berkshire and East Asia Power facilities and have a $9 million interest in Saba. There is no recourse to El Paso under the loans at these investments. In addition, we have had events of default or other events that could lead to an event of default upon notice from the

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lenders on other projects, but we do not believe any of these defaults will have a material impact on our or our subsidiaries financial statements.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2004, we had outstanding letters of credit of approximately $1.3 billion, of which $107 million was supported with cash collateral, and $1.2 billion were issued under our credit agreement. Included in this amount were $0.9 billion of letters of credit securing our recorded obligations related to price risk management activities.

Available Capacity Under Shelf Registration Statements

We maintain a shelf registration statement with the SEC that allows us to issue a combination of debt, equity and other instruments, including trust preferred securities of two wholly owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we would be required to issue full and unconditional guarantees on these securities. As of December 31, 2004, we had $926 million remaining capacity under this shelf registration statement; however, we are unable to access this capacity until January 2006, due to the untimely filing of our 2003 annual and quarterly 2004 financial statements.

16. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into financing transactions that have been accomplished through the sale of preferred interests in consolidated subsidiaries. During 2003, we repaid approximately $2 billion of these preferred interests, reclassified $625 million to long-term financing obligations as a result of adopting SFAS No. 150 (see Note 1, on page F-44) and eliminated $300 million in consolidation because we acquired the holder of those preferred interests. Our remaining preferred interest is discussed below.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co. (EPTP) issued 6 million shares of publicly registered 8.25 percent cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at our option, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time. EPTP indirectly owns our marketing and trading businesses, substantially all of our domestic and international power businesses, and TGP. While not required, the following financial information is intended to provide additional information of EPTP to its preferred security holders:

	Year Ended December 31,		
	2004	2003	2002
		(In millions) (unaudited)	
Operating results data:			
Operating revenues	$ 812	$ 1,459	$ 1,132
Operating expenses	1,131	1,865	2,268
Loss from continuing operations	(399)	(377)	(1,288)
Net loss	(399)	(377)	(1,510)

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	December 31,	
	2004	2003
	(In millions) (unaudited)	
Financial position data:		
Current assets	$ 2,783	$ 4,217
Non-current assets	9,001	9,892
Short-term debt	402	1,111
Other current liabilities	4,693	5,409
Long-term debt	2,183	2,545
Other non-current liabilities	2,580	2,642
Securities of subsidiaries	3	28
Equity in net assets	1,923	2,374

17. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2004, our master settlement agreement, along with other separate settlement agreements, became effective with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada. This resolves the principal litigation, investigations, claims and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western U.S. (the Western Energy Settlement). As part of the Western Energy Settlement, we admitted no wrongdoing but agreed, among other things, to make various cash payments and modify an existing power supply contract. We also entered into a Joint Settlement Agreement or JSA where we agreed, subject to the limitations in the JSA, to (1) make 3.29 Bcf/d of capacity available to California to the extent shippers sign firm contracts for that capacity, (2) maintain facilities sufficient to physically deliver 3.29 Bcf/d to California; (3) construct facilities which we completed in 2004, (4) clarify certain shippers recall rights on the system and (5) bar any of our affiliated companies from obtaining additional firm capacity on our EPNG pipeline system during a five year period from the effective date of the settlement.

In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA described above with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC s ruling to the U.S. Court of Appeals for the District of Columbia, where this matter is pending. We expect this appeal to be fully briefed by the summer of 2005.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. During 2003, we recorded additional pretax charges of $104 million based upon reaching definitive settlement agreements. Charges and expenses associated with the Western Energy Settlement are included in operations and maintenance expense in our consolidated statements of income. When the settlement became effective in June 2004, $602 million was released to the settling parties. This amount is shown as a reduction of our cash flows from operations in the second quarter of 2004. Of the amount released, $568 million had been previously held in an escrow account pending final approval of the settlement. The release of these restricted funds is included as an increase in our cash flows from investing activities. Our remaining obligation as of December 31, 2004 under the Western Energy Settlement consists of a discounted 20-year cash payment obligation of $395 million and a price reduction under a power supply contract, which is included in our price risk management activities. In connection with the Western Energy Settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining cash payment obligation. The collateral requirement is being reduced as payments under the 20 year

obligation are made. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 7, on page F-68.

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Shareholder/Derivative/ERISA Litigation

Shareholder Litigation. Since 2002, twenty-nine purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our current and former officers and directors. One of these lawsuits has been dismissed and the remaining 28 lawsuits have been consolidated in federal court in Houston, Texas. The consolidated lawsuit generally challenges the accuracy or completeness of press releases and other public statements made during the class period from 2001 through early 2004, related to wash trades, mark-to-market accounting, off-balance sheet debt, overstatement of oil and gas reserves and manipulation of the California energy market. The consolidated lawsuit is currently stayed.

Derivative Litigation. Since 2002, five shareholder derivative actions have also been filed. Three of the actions allege the same claims as in the consolidated shareholder class action suit described above, with one of the actions including a claim for compensation disgorgement against certain individuals. These actions are currently stayed. Two actions are now consolidated in state court in Houston, Texas and generally allege that manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value.

ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. This lawsuit has been stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits. There are certain deductibles and co-pay obligations under some of those insurance coverages for which we have established certain accruals we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Company and Case Corporation*. The suit alleges, among other things, that El Paso violated ERISA, and that Case should be required to pay all amounts above the cap. Although such amounts will vary over time, the amounts above the cap have recently been approximately $1.8 million per month. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend, and hold Case harmless for the amounts it would be required to pay. In February 2004, a judge ruled that Case would be required to pay the amounts incurred above the cap. Furthermore, in September 2004, a judge ruled that pending resolution of this matter, El Paso must indemnify and reimburse Case for the monthly amounts above the cap. Our motion for reconsideration of these orders was denied in November 2004. These rulings have been appealed. In the meantime, El Paso will indemnify Case for any payments Case makes above

the cap. While we believe we have meritorious defenses to the

plaintiffs claims and to Case s crossclaim, if we were required to ultimately pay for all future amounts above the cap, and if Case were not found to be responsible for these amounts, our exposure could be as high as $400 million, on an undiscounted basis.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. In January 2005 a purported class action lawsuit styled *Leggett et al. v Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of the all residential and commercial purchasers of natural gas in the state of Tennessee during the past three years. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. The Company has also had similar claims asserted by individual commercial customers. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. A number of our subsidiaries were named defendants in actions filed in 1997 brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss have been filed on behalf of all defendants. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action has since been filed as to the heating content claims. The plaintiffs have filed motions for class certification in both proceedings and the defendants have filed briefs in opposition thereto. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs seek an accounting and damages for alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in

Oklahoma, plus interest from the time such amounts were allegedly due, as well as punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties have completed discovery. The plaintiffs have filed expert reports alleging damages in excess of $1 billion. Pursuant to a recent summary judgment decision, the court ruled that claims previously released by the settlement of *Altheide v. Meridian,* a nation-wide royalty class action against Burlington and its affiliates are barred from being reasserted in this action. We believe that this ruling eliminates a material, but yet unquantified portion of the alleged class damages. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Resources, Inc., and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed. We believe we have substantial defenses to the plaintiffs claims as well as to the claims for indemnity by Burlington. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $186 million at December 31, 2004. We have political risk insurance that covers a portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil with property, plant and equipment having a net book value of $700 million as of December 31, 2004. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are paid by Petrobras until August 2007 under a participation agreement. Petrobras failed to make any payments that were due under the participation agreement for December 2004 and January 2005. In 2005, Petrobras obtained a ruling from a Brazilian court directing Petrobras to deposit one-half of the payments to a court account and to pay us the other half. We are appealing this ruling. Petrobras has also failed to make any payments required under the court order. As of December 31, 2004, our accounts receivable balance is approximately $20 million. Petrobras has also filed a notice of arbitration with an international arbitration institution that effectively seeks rescission of the participation agreement and reimbursement of a portion of the capacity payments that it has made. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras s obligation to provide a firm gas supply to the project through 2012. We believe we have substantial defenses to the claims of Petrobras and will vigorously defend our legal rights. In addition, we will continue to seek reasonable negotiated settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $320 million at December 31, 2004, and Petrobras non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $320 million of debt as current. We also have restricted cash balances of approximately $76 million as of December 31, 2004, which are reflected in current assets, related to required debt service reserve balances, debt service payment accounts and funds held for future distribution by Macae. We have also issued cash collateralized letters of credit of approximately $47 million as part of funding the required debt service reserve accounts. The

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restricted cash related to these letters of credit has also been classified as a current asset. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise certain remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

In light of the pending arbitration proceedings, we have evaluated whether any impairment of our investment in the project is required at December 31, 2004. Based upon our review of the possible outcomes of the arbitration and potential settlements of the dispute, we do not believe that an impairment of our investment is required at this time. However, if our assessment of the potential outcomes of the arbitration or settlement opportunities changes, we may be required to write down some or all of our investment in the project. In the event that the lenders call the loans and ultimately foreclose on the project, our loss would be approximately $500 million as of December 31, 2004. As new information becomes available or future material developments occur, we will reassess our carrying value of this investment.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE s potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney s fees, and court costs. Our costs and legal exposure related to these lawsuits are not currently determinable.

Wise Arbitration. William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached employment and other agreements by failing to make certain payments to him following his departure from El Paso in 2003. Discovery is underway, with a hearing scheduled in the summer of 2005.

Government Investigations

Power Restructuring. In October 2003, we announced that the SEC had authorized the staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We have cooperated with the SEC investigation.

Wash Trades. In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning round trip or wash trades. We have complied with those requests. We have also cooperated with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production and the restatement of such hedges.

Price Reporting. In October 2002, the FERC issued data requests regarding price reporting of transactional data to the energy trade press. We provided information to the FERC, the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney s investigation of this matter.

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand

jury subpoenas for documents with regard to these reserve revisions. We are cooperating with the SEC s and the U.S. Attorney s investigations of this matter.

Storage Reporting. In November 2004, ANR and TGP received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the Energy Information Administration (EIA) for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR and TGP provided information on their weekly EIA submissions for two weeks in November 2004. Neither ANR nor TGP s submissions to the EIA were revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC and ANR provided the requested information. On December 17, 2004, the FERC held a press conference in which they disclosed that their inquiry had determined that an unaffiliated third party was the source of the downward revision.

Iraq Oil Sales. In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records relating to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement in connection with Coastal and El Paso s participation in the Oil for Food Program. We have also received informal requests for information and documents from the United States Senate s Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to Coastal s purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney s, the SEC s, the Senate Subcommittee s, and the House Committee s investigations of this matter.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation s Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations. In December 2003, the matter was referred to the Department of Justice.

After a public hearing conducted by the National Transportation Safety Board (NTSB) on its investigation into the Carlsbad rupture, the NTSB published its final report in April 2003. The NTSB stated that it had determined that the probable cause of the August 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG s corrosion control program failed to prevent, detect, or control internal corrosion in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG s internal corrosion control program.

In November 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture and cooperated fully in responding to the subpoena. That subpoena has since expired. In December 2003 and January 2004, eight current and former employees were served with testimonial subpoenas issued by the grand jury. Six individuals testified in March 2004. In April 2004, we and EPNG received a new federal grand jury subpoena requesting additional documents. We have responded fully to this subpoena. Two additional employees testified before the grand jury in June 2004.

A number of civil actions were filed against EPNG in connection with the rupture which have now been settled or should be fully covered by insurance.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

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Rates and Regulatory Matters

Pipeline Integrity Costs. 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.

Inquiry Regarding Income Tax Allowances. In December 2004, the FERC issued a Notice of Inquiry (NOI) in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC sought comments on whether the court s reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines, including those pipelines which are jointly owned with unaffiliated parties.

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

Other Contingencies

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. (ENA) and Enron Power Marketing, Inc. (EPMI) filed for Chapter 11 bankruptcy protection in New York. We had various contracts with Enron marketing and trading entities, and most of the trading-related contracts were terminated due to the bankruptcy. In October 2002, we filed proofs of claims against the Enron trading entities totaling approximately $317 million.

Enron Trading Claims. We have largely sold or settled all of our original claims of our trading entities with Enron. In particular, on June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved most of our trading or merchant issues between the parties for which final payments were made in the third quarter of 2004. The only remaining trading claims involve our European trading businesses, claims against Enron Capital and Trade Resources Limited, which are subject to separate proceedings in the United Kingdom, in addition to a corresponding claim against Enron Corp. based on a corporate guarantee. After considering the valuation and setoff arguments and the reserves we have established, we believe our overall remaining trading exposure to Enron is $3 million.

Enron Pipeline Claims. In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts were rejected, and our pipeline subsidiaries filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. EPNG expects that Enron will vigorously contest these claims. Our remaining pipeline claimants, ANR TGP and WIC, are in various stages of attempting to resolve their claims with Enron. Given the uncertainty of the bankruptcy process, the results are uncertain. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since that time.

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Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil. Our total investment in Brazil was approximately $1.6 billion as of December 31, 2004. Although economic conditions have generally improved over the last year, Brazil has experienced high interest rates on local debt and has experienced restrictions on the availability of foreign funds and investment. In addition, in a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. We also own an investment in a power plant in Brazil called Porto Velho. The Porto Velho project is in the process of negotiating certain provisions of its PPAs with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant s capacity. The project expects to replace or repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the proposed amendments do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was $292 million at December 31, 2004.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the item, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, then we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of December 31, 2004, we had approximately $592 million net of related insurance receivables accrued for our outstanding legal and other contingencies, including amounts accrued for our Western Energy Settlement.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2004, we had accrued approximately $380 million, including approximately $373 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $7 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $380 million accrual, $100 million was reserved for facilities we currently operate, and $280 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

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 if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	December 31, 2004	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 100	$ 111
Non-operating	249	384
Superfund	31	52

Total	$ 380	$ 547

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Below is a reconciliation of our accrued liability from January 1, 2004, to December 31, 2004 (in millions):

Balance as of January 1, 2004	$ 412
Additions/adjustments for remediation activities	17
Payments for remediation activities	(51)
Other changes, net	2
Balance as of December 31, 2004	$ 380

For 2005, we estimate that our total remediation expenditures will be approximately $64 million. In addition, we expect to make capital expenditures for environmental matters of approximately $62 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the EPA List of Hazardous Substances (HSL), at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations, and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at its Pennsylvania and New York stations.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of December 31, 2004, TGP had pre-collected PCB costs by approximately $125 million. This pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of December 31, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $97 million for estimated future refund obligations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 61 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $52 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as

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increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current environmental reserves are adequate.

Commitments and Purchase Obligations

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2005 until 2053. As of December 31, 2004, our total commitments under operating leases were approximately $442 million. Minimum annual rental commitments under our operating leases at December 31, 2004, were as follows:

Year Ending December 31,		**Operating Leases**
		(In millions)
2005	$	79
2006		66
2007		51
2008		43
2009		40
Thereafter		163
Total	$	442

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $28 million due in the future under noncancelable subleases. Rental expense on our operating leases for the years ended December 31, 2004, 2003 and 2002 was $101 million, $113 million and $116 million.

In May 2004, we announced we would consolidate our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004 we have established an accrual totaling $80 million to record the liability, net of sublease rentals, for our obligations under our existing lease terms. We currently lease approximately 888,000 square feet of office space in the buildings we are vacating under various leases with lease terms expiring through 2014. See Note 4, on page F-64, for additional information regarding these lease terminations.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance 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. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include indemnification 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 at the time a guarantee or indemnity arrangement is entered into and in each period thereafter 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 had approximately $40 million of financial and performance guarantees, and indemnification arrangements not otherwise reflected in our financial statements.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2004, we had firm commitments under tolling, transportation and storage capacity contracts of $1.5 billion, commodity purchase commitments

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of $149 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $224 million.

18. Retirement Benefits

Pension Benefits

Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat or Coastal receive the greater of cash balance benefits or transition benefits under the prior plan formulas. Transition benefits reflect prior plan accruals for these employees through December 31, 2001, December 31, 2004 and March 31, 2006. We do not anticipate making any contributions to this pension plan in 2005.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We also maintain two other pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. The SERP and the frozen plans together are referred to below as other pension plans. We also participate in one multi-employer pension plan for the benefit of our former employees who were union members. Our contributions to this plan during 2004, 2003 and 2002 were not material. We expect to contribute $5 million to the SERP in 2005. We do not anticipate making any contributions to our other pension plans in 2005.

During 2004, we recognized a $4 million curtailment benefit in our pension plans primarily related to a reduction in the number of employees that participate in our pension plan, which resulted from our various asset sales and employee severance efforts. During 2003, we recognized $11 million in charges in our pension plans that resulted from employee terminations and our internal reorganization.

Retirement Savings Plan

We maintain a defined contribution plan covering all of our U.S. employees. Prior to May 1, 2002, we matched 75 percent of participant basic contributions up to 6 percent, with the matching contributions being made to the plan s stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, we suspended the matching contributions, but reinstituted it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, we increased the matching contributions to 75 percent of participant basic contributions up to 6 percent. Amounts expensed under this plan were approximately $16 million, $14 million and $28 million for the years ended December 31, 2004, 2003 and 2002.

Other Postretirement Benefits

We provide postretirement medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. We expect to contribute $63 million to our postretirement plans in 2005. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits.

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Below is our projected benefit obligation, accumulated benefit obligation, fair value of plan assets as of September 30, our plan measurement date, and related balance sheet accounts for our pension plans as of December 31:

	Primary Pension Plan		Other Pension Plans	
	2004	2003	2004	2003
	(In millions)			
Projected benefit obligation	$ 1,948	$ 1,928	$ 170	$ 163
Accumulated benefit obligation	1,934	1,902	169	163
Fair value of plan assets	2,196	2,104	93	93
Accrued benefit liability			74	69
Prepaid benefit cost	960	960		21
Accumulated other comprehensive loss			70	37

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

	2004	2003
	(In millions)	
Projected benefit obligation	$ 170	$ 134
Accumulated benefit obligation	169	134
Fair value of plan assets	93	63

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded other comprehensive income (loss) of $(33) million in 2004 and $18 million in 2003 related to the change in this additional minimum liability.

Below is the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our pension and other postretirement benefit plans. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$ 2,091	$ 2,088	$ 575	$ 558
Service cost	31	36	1	1
Interest cost	121	134	34	35
Participant contributions			27	24
Settlements, curtailments and special termination benefits	(3)			(6)
Actuarial loss (gain)	76	22	(20)	50
Benefits paid	(198)	(189)	(76)	(87)

Projected benefit obligation at end of period	$ 2,118	$ 2,091	$ 541	$ 575
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 2,197	$ 2,072	$ 196	$ 164
Actual return on plan assets	277	285	12	25
Employer contributions	12	29	61	70
Participant contributions			27	24
Benefits paid	(198)	(189)	(76)	(87)
Administrative expenses	1			
Fair value of plan assets at end of period	$ 2,289	$ 2,197	$ 220	$ 196

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	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Reconciliation of funded status:				
Fair value of plan assets at September 30	$ 2,289	$ 2,197	$ 220	$ 196
Less: Projected benefit obligation at end of period	2,118	2,091	541	575
Funded status at September 30	171	106	(321)	(379)
Fourth quarter contributions and income	2	2	13	17
Unrecognized net actuarial loss[1]	800	868	32	57
Unrecognized net transition obligation		1	8	15
Unrecognized prior service cost	(17)	(28)	(6)	(7)
Prepaid (accrued) benefit cost at December 31	$ 956	$ 949	$ (274)	$ (297)

[1] The decrease in unrecognized net actuarial loss in our pension benefits was primarily due to historical changes and assumptions on discount rates, expected return on plan assets and rate of compensation increase. We recognize the difference between the actual return and our expected return over a three year period as permitted by SFAS No. 87. The decrease in unrecognized net actuarial loss in our other postretirement benefits was primarily due to the adoption of FSP No. 106-2.

The portion of our other postretirement benefit obligation included in current liabilities was $38 million and $45 million as of December 31, 2004 and 2003.

Future benefits expected to be paid from our pension plans and our other postretirement plans as of December 31, 2004, are as follows:

Year Ending December 31,	Pension Benefits	Other Postretirement Benefits[1]
	(In millions)	
2005	$ 160	$ 57
2006	160	52
2007	161	50
2008	161	48
2009	160	46
2010-2014	788	208
Total	$ 1,590	$ 461

(1) Includes a reduction of $3 million in each year excluding 2005 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	(In millions)					
Service cost	$ 31	$ 36	$ 33	$ 1	$ 1	$ 2
Interest cost	121	134	135	34	35	38
Expected return on plan assets	(187)	(227)	(260)	(11)	(9)	(9)
Amortization of net actuarial (gain) loss	47	7		4	1	(1)
Amortization of transition obligation		(1)	(6)	8	8	8
Amortization of prior service cost[1]	(3)	(3)	(3)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	(4)	11			(6)	
Net benefit cost (income)	$ 5	$ (43)	$ (101)	$ 35	$ 29	$ 37

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(1) As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit costs of our pension and other postretirement plans for 2004, 2003 and 2002:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	(Percent)			(Percent)		
Assumptions related to benefit obligations at September 30:						
Discount rate	5.75	6.00		5.75	6.00	
Rate of compensation increase	4.00	4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.00	6.75	7.25	6.00	6.75	7.25
Expected return on plan assets(1)	8.50	8.80	8.80	7.50	7.50	7.50
Rate of compensation increase	4.00	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 26 percent to 27 percent on other postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio. For 2005, the assumed expected return on assets for pension benefits will be reduced to 8 percent.

Actuarial estimates for our other postretirement benefit plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

	2004	2003
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	19	21
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(18)	(19)

Plan Assets

The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

	Pension Plans			Other Postretirement Plans		
Asset Category	**Target**	**Actual 2004**	**Actual 2003**	**Target**	**Actual 2004**	**Actual 2003**
		(Percent)			**(Percent)**	
Equity securities[1]	60	62	70	65	60	29
Debt securities	40	37	29	35	33	60
Other		1	1		7	11
Total	100	100	100	100	100	100

[1] Actuals for our pension plans include $42 million (1.8 percent of total assets) and $33 million (1.5 percent of total assets) of our common stock at September 30, 2004 and September 30, 2003.

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The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

In 2003, we modified our target asset allocations for our other postretirement benefit plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2004 were close to our targets. During 2004, we modified our target and actual asset allocations for our pension plans to reduce our equity allocation to 60 percent of total plan assets. Correspondingly, our 2005 assumption related to the expected return on plan assets were reduced from 8.5 percent to 8.0 percent to reflect this change.

19. Capital Stock

Common Stock

In 2003 and 2004, we issued 26.4 million shares to satisfy our obligations under the Western Energy Settlement (See Note 17, on page F-87). In 2003, we also issued 15 million shares as part of an offer to exchange our equity security units for common stock (see Note 15, on page F-79).

Dividend

For the year ended December 31, 2004, we paid dividends of $101 million to common stockholders. On February 18, 2005, we declared quarterly dividends of $0.04 per share on our common stock, payable on April 4, 2005 to the shareholders of record on March 4, 2005. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit.

El Paso Tennessee Pipeline Co., our subsidiary, pays dividends of approximately $6 million each quarter on its Series A cumulative preferred stock, which is 8.25 percent per annum (2.0625 percent per quarter).

20. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using Accounting Principles Board Opinion No. 25 and its related interpretations. Under our employee plans, we may issue incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, stock appreciation rights, phantom stock options, and performance units. Under our non-employee director plan, we may issue deferred shares of common stock. We have reserved approximately 68 million shares of common stock for existing and future stock awards, including deferred shares. As of December 31, 2004, approximately 28 million shares remained unissued.

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Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2004, 2003 and 2002. Our stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. Prior to 2004, we also granted options to non-employee members of the Board of Directors at fair market value on the grant date that were exercisable immediately. A summary of our stock option transactions, stock options outstanding and stock options exercisable as of December 31 is presented below:

	Stock Options					
	2004		2003		2002	
	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	36,245,014	$ 47.90	43,208,374	$ 49.16	44,822,146	$ 50.02
Granted	4,842,453	$ 7.16	1,180,041	$ 7.29	3,435,138	$ 35.41
Exercised	(3,193)	$ 7.64			(310,611)	$ 22.44
Converted[1]	(11,333)	$ 42.99	(871,250)	$ 42.00		
Forfeited or canceled	(7,149,363)	$ 44.75	(7,272,151)	$ 49.53	(4,738,299)	$ 51.83
Outstanding at end of year	33,923,578	$ 42.73	36,245,014	$ 47.90	43,208,374	$ 49.18
Exercisable at end of year	28,455,056	$ 49.45	28,703,151	$ 46.04	25,493,152	$ 43.00
Weighted average fair value of options granted during the year		$ 2.69		$ 3.21		$ 14.23

[1] Includes the conversion of stock options into common stock and cash at no cost to employees based upon achievement of certain performance targets and lapse of time. These options had an original stated exercise price of approximately $43 per share and $42 per share in 2004 and 2003.

The following table summarizes the range of exercise prices and the weighted-average remaining contractual life of options outstanding and the range of exercise prices for the options exercisable at December 31, 2004.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price

$ 0.00 - $21.39	7,537,238	7.1	$	9.25	2,154,339	$	14.35
$21.40 - $42.89	8,761,610	2.9	$	37.53	8,707,300	$	37.52
$42.90 - $64.29	12,302,057	3.6	$	54.88	12,272,411	$	54.91
$64.30 - $70.63	5,322,673	4.7	$	70.59	5,321,006	$	70.59
	33,923,578	4.4	$	42.73	28,455,056	$	49.45

The fair value of each stock option granted used to complete pro forma net income disclosures (see Note 1, on page F-44) is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption:	**2004**	**2003**	**2002**
Expected Term in Years	5.35	6.19	6.95
Expected Volatility	45%	52%	43%
Expected Dividends	2.1%	2.2%	1.8%
Risk-Free Interest Rate	3.7%	3.4%	3.2%

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Restricted Stock

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our officers and employees. These shares carry voting and dividend rights; however, sale or transfer of the shares is restricted. These restricted stock awards vest over a specific period of time and/or if we achieve established performance targets. Restricted stock awards representing 3.1 million, 0.4 million, and 1.4 million shares were granted during 2004, 2003 and 2002 with a weighted-average grant date fair value of $8.63, $7.46 and $38.45 per share. At December 31, 2004, 3.9 million shares of restricted stock were outstanding. The value of restricted shares subject to performance vesting is determined based on the fair market value on the date performance targets are achieved, and this value is charged to compensation expense ratably over the required service or restriction period. The value of time vested restricted shares is determined at their issuance date and this cost is amortized to compensation expense over the vesting period. For 2004, 2003 and 2002, these charges totaled $23 million, $60 million and $73 million. We have $20 million on our balance sheet as of December 31, 2004 related to unamortized compensation that will be charged to expense over the vesting period of the restricted stock.

Performance Units

In the past, we awarded eligible officers performance units that were payable in cash or stock at the end of the vesting period. The final value of the performance units varied according to the plan under which they were granted, but was usually based on our common stock price at the end of the vesting period or total shareholder return during the vesting period relative to our peer group. The value of the performance units was charged ratably to compensation expense over the vesting period with periodic adjustments to account for the fluctuation in the market price of our stock or changes in expected total shareholder return. We recorded a credit to compensation expense in 2002 of $11 million upon the reduction of our performance unit liability by $21 million due to a reduction in our expected total shareholder return. In July 2003, all outstanding performance units vested at the Below Threshold level and the Compensation Committee of our Board of Directors determined that there would be no payout for the performance units. Accordingly, we reversed the remaining liability for these units and recorded income of $16 million.

Employee Stock Purchase Program

In October 1999, we implemented an employee stock purchase plan under Section 423 of the Internal Revenue Code. The plan allowed participating employees the right to purchase our common stock on a quarterly basis at 85 percent of the lower of the market price at the beginning or at the end of each calendar quarter. Five million shares of common stock are authorized for issuance under this plan. For the year ended December 31, 2002, we sold 1.4 million shares of our common stock to our employees. Effective January 1, 2003, we suspended our employee stock purchase program.

21. Business Segment Information

Our 2002 Pipelines segment results and the amounts reported as a cumulative effect of accounting change in 2002 have been restated for errors resulting from the misinterpretation of FAS 141 and 142 upon the adoption of these standards. We have restated our 2003 segment disclosure information to adjust income taxes allocated to CTA on certain of our foreign investments with CTA balances. In 2004, our Power and Marketing and Trading segments and corporate operations have been restated to adjust the amount of losses on long-lived assets, earnings from unconsolidated affiliates and other income for certain foreign entities with CTA balances and related tax effects. See Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatements and the manner in which our business segments and other operations were affected.

During 2004, we reorganized our business structure into two primary business lines, regulated and non-regulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established individual Power and Marketing and Trading segments. All periods presented reflect this change in segments. Our regulated business consists of our Pipelines segment, while our

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non-regulated 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 operations include our general and administrative functions as well as a telecommunications business, and various other contracts and assets, all of which are immaterial. These other assets and contracts include financial services, LNG and related items.

During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations. Our operating results for all periods presented reflect these changes.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the U.S. We conduct our activities primarily through eight wholly owned and four partially owned interstate transmission systems along with five underground natural gas storage entities and an LNG terminalling facility.

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 U.S., Production has onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico.

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.

Our Power segment owns and has interests in domestic and international power assets. As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also had 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.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2004, 2003 and 2002.

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 substantial 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

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such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

	2004 (Restated)	2003 (Restated)	2002 (Restated)
		(In millions)	
Total 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)

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

	As of or for the Year Ended December 31, 2004						
	Regulated		Non-regulated				
	Pipelines	Production	Marketing and Trading (Restated)	Power (Restated)	Field Services	Corporate[1] (Restated)	Total (Restated)
				(In millions)			
Revenue from external customers							
Domestic	$ 2,554	$ 535[2]	$ 697	$ 241	$ 1,203	$ 132	$ 5,362
Foreign	9	26[2]	2	460		15	512
Intersegment revenue	88	1,174[2]	(1,207)	94	159	(308)	
Operation and maintenance	777	365	53	374	102	201	1,872
Depreciation, depletion, and amortization	410	548	13	54	12	51	1,088
(Gain) loss on long-lived assets	(1)	8		599	508	(6)	1,108
Operating income (loss)	$ 1,129	$ 726	$ (562)	$ (424)	$ (465)	$ (214)	$ 190
Earnings from unconsolidated affiliates	173	4		(249)	618		546
Other income	33	4	23	83	2	48	193
Other expense	(4)			(9)	(35)	(51)	(99)
EBIT	$ 1,331	$ 734	$ (539)	$ (599)	$ 120	$ (217)	$ 830

Discontinued operations, net of income taxes	$	$ (36)	$	$	$	$ (78)	$ (114)
Assets of continuing operations [3]							
Domestic	15,930	3,714	2,372	982	686	4,424	28,108
Foreign[4]	58	366	32	2,617		96	3,169
Capital expenditures and investments in and advances to unconsolidated affiliates, net [5]	1,047	728		29	(5)	10	1,809
Total investments in unconsolidated affiliates	1,032	6		1,262	308	6	2,614

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $308 million and an operation and maintenance expense elimination of $25 million, which is included in the Corporate column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Excludes assets of discontinued operations of $106 million (see Note 3, on page F-60).

(4) Of total foreign assets, approximately $1.3 billion relates to property, plant and equipment and approximately $1.5 billion relates to investments in and advances to unconsolidated affiliates.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

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	As of or for the Year Ended December 31, 2003						
	Regulated	Non-regulated					
	Pipelines	Production (Restated)	Marketing and Trading	Power	Field Services	Corporate[1]	Total (Restated)
	(In millions)						
Revenue from external customers							
Domestic	$ 2,527	$ 201[2]	$ 1,430	$ 515	$ 1,153	$ 113	$ 5,939
Foreign	2			516	2	13	533
Intersegment revenue	118	1,940[2]	(2,065)	145	374	(316)	196[3]
Operation and maintenance	720	342	183	562	110	93	2,010
Depreciation, depletion, and amortization	386	576	25	91	31	67	1,176
Western Energy Settlement	127		(25)			2	104
(Gain) loss on long-lived assets	(10)	5	(3)	185	173	510	860
Operating income (loss)	$ 1,063	$ 1,073	$ (819)	$ (13)	$ (193)	$ (706)	$ 405
Earnings (losses) from unconsolidated affiliates	119	13		(91)	329	(7)	363
Other income	57	5	12	90		39	203
Other expense	(5)		(2)	(14)	(3)	(178)	(202)
EBIT	$ 1,234	$ 1,091	$ (809)	$ (28)	$ 133	$ (852)	$ 769
Discontinued operations, net of income taxes	$	$ 24	$	$	$	$ (1,303)	$ (1,279)
Cumulative effect of accounting changes, net of income taxes	(4)	(3)			(2)		(9)
Assets of continuing operations[4]							
Domestic	15,659	3,459	2,661	3,897	1,990	3,890	31,556
Foreign	27	308	5	3,102		141	3,583
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	837	1,300	(1)	1,083	(15)	89	3,293

Total investments in unconsolidated affiliates	1,018	79		1,652	655	5	3,409

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $316 million and an operation and maintenance expense elimination of $59 million, which is included in the Corporate column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $1.8 billion (see Note 3, on page F-60).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital. Our Power Segment Includes $1 billion to acquire remaining interest in Chaparral and Gemstone (see Note 2, on page F-56).

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	As of or for the Year Ended December 31, 2002						
	Regulated	Non-regulated					
	Pipelines (Restated)	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total (Restated)
	(In millions)						
Revenue from external customers							
Domestic	$ 2,389	$ 308[2]	$ 926	$ 1,268	$ 1,145	$ 97	$ 6,133
Foreign	3		(41)	361	3	79	405
Intersegment revenue	218	1,623[2]	(2,209)	43	881	(213)	343
Operation and maintenance	752	368	173	520	179	99	2,091
Depreciation, depletion, and amortization	374	601	11	45	56	72	1,159
Western Energy Settlement	412		487				899
(Gain) loss on long-lived assets	(13)	(1)		160	(179)	214	181
Operating income (loss)	$ 788	$ 803	$ (1,993)	$ 352	$ 273	$ (394)	$ (171)
Earnings (losses) from unconsolidated affiliates	10	7		(256)	18	7	(214)
Other income	34	1	19	40	3	100	197
Other expense	(4)	(3)	(3)	(124)	(5)	(100)	(239)
EBIT	$ 828	$ 808	$ (1,977)	$ 12	$ 289	$ (387)	$ (427)
Discontinued operations, net of income taxes	$	$ (68)	$	$	$	$ (357)	$ (425)
Cumulative effect of accounting changes, net of income taxes			(222)	14			(208)
Assets of continuing operations [4]							
Domestic	14,727	3,495	5,568	2,759	2,714	4,265	33, 528
Foreign	59	208	844	2,485	14	277	3,887
Capital expenditures and investments in and advances to unconsolidated affiliates, net [5]	1,075	2,114	47	91	187	48	3,562

Total investments in unconsolidated affiliates	992	87		2,725	922	23	4,749

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $213 million and an operation and maintenance expense elimination of $41 million, which is included in the Corporate column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $4.5 billion (see Note 3, on page F-60).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

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

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants, and gathering systems. Our investment balance was less than our equity in the net assets of these investments by $265 million and $136 million as of December 31, 2004 and 2003. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the year ended December 31:

	Net Ownership Interest		Investment		Earnings from Unconsolidated Affiliates		
	2004	2003	2004	2003 (Restated)	2004 (Restated)	2003	2002 (Restated)
	(Percent)		(In millions)		(In millions)		
Domestic:							
Citrus	50	50	$ 589	$ 593	$ 65	$ 43	$ 43
Enterprise Products Partners[1]	(1)		257		6		
GulfTerra Energy Partners[1]		(1)		599	601	419	69
Midland Cogeneration Venture[2]	44	44	191	348	(171)	29	28
Great Lakes Gas Transmission[3]	50	50	316	325	65	57	63
Javelina	40	40	45	40	15	(2)	
Milford[4]					(1)	(88)	(22)
Bastrop Company[5]		50		73	(1)	(48)	(5)
Mobile Bay Processing[5]		42		11		(48)	(2)
Blue Lake Gas Storage[6]		75		30		9	8
Chaparral Investors (Electron)[7]						(207)	(62)
Linden Venture L.P. (East Coast Power)						65	
Dauphin Island[5]		15				(40)	(1)
Alliance Pipeline Limited Partnership[4]							25
CE Generation[4]							(52)
Aux Sable NGL							(50)
Other Domestic Investments	various	various	136	137	26	26	29
Total domestic			1,534	2,156	605	215	71
Foreign:							
Korea Independent Energy Corporation	50	50	176	145	22	29	24
Araucaria Power[8]	60	60	186	181			
EGE Itabo	25	25	88	87	1	1	(2)
Bolivia to Brazil Pipeline	8	8	86	66	24	17	2

EGE Fortuna	25	25	65	59	6	3	5
Meizhou Wan Generating	26	25	52	63	(14)	8	(20)
Enfield Power[9]	25	25	51	55	1	3	(3)
Aguaytia Energy	24	24	39	51	(5)	4	3
San Fernando Pipeline	50	50	46	41	13	5	
Habibullah Power[10]	50	50	20	48	(46)	(3)	10
Gasoducto del Pacifico Pipeline	22	22	33	37	4	3	(2)
Samalayuca[11]	50	50	35	24	5	3	21
Saba Power Company	94	94	7	59	(51)	4	7
Australian Pipelines[5]		33		38	4	(3)	(142)
UnoPaso[6]		50		73	4	14	6
Diamond Power (Gemstone)[7]						17	109
CAPSA[4]						24	(262)
PPN[12]	26	26					(50)
Agua del Cajon[4]							(24)
Other Foreign Investments[10]	various	various	196	226	(27)	19	33
Total foreign			1,080	1,253	(59)	148	(285)
Total investments in unconsolidated affiliates			$ 2,614	$ 3,409			
Total earnings (losses) from unconsolidated affiliates					$ 546	$ 363	$ (214)

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(1) As of December 31, 2003, we owned an effective 50 percent interest in the one percent general partner of GulfTerra, approximately 17.8 percent of the partnership s common units and all of the outstanding Series C units. During 2004 we sold our remaining interest in GulfTerra to Enterprise for cash and equity interests in Enterprise and recognized a $507 million gain. As of December 31, 2004, our ownership consisted of a 9.9 percent interest in the two percent general partner of Enterprise and approximately 3.7 percent of Enterprise s common units. In January 2005, we sold all of these remaining interests to Enterprise. For a further discussion of our interests in GulfTerra and Enterprise, see page F-112.

(2) Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.

(3) Includes a 47 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 3 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.

(4) In 2003 we completed the sale or transfer of our interest in this investment.

(5) In 2004 we completed the sale of our interest in this investment.

(6) Consolidated in 2004.

(7) This investment was consolidated in 2003.

(8) Our investment in Araucaria Power was included in Diamond Power (Gemstone) prior to 2003.

(9) We have signed an agreement to sell our interest in the project and expect to close the transaction in the first half of 2005.

(10) As of December 31, 2004 and 2003, we also had outstanding advances of $64 million and $90 million related to our investment in Habibullah Power. We also had other outstanding advances of $318 million and $327 million related to our other foreign investments as of December 31, 2004 and 2003, of which $307 million and $290 million are related to our investment in Porto Velho.

(11) Consists of investments in a power facility and pipeline. In 2002, we sold our investment in the power facility.

(12) Impaired in 2002 due to our inability to recover our investment. Earnings generated in 2003 and 2004 did not improve the recoverability of this investment. We sold our interest in March 2005.

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Our impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates during 2004, 2003 and 2002 consisted of the following:

Investment	Pre-tax Gain (Loss)	Cause of Impairments or Gain (Loss)
	(In millions)	
2004 (Restated)		
Gain on sale of interests in GulfTerra[1]	$ 507	Sale of investment
Asian power investments[2]	(182)	Anticipated sales of investments
Midland Cogeneration Venture	(161)	Decline in investment s fair value based on increased fuel costs
Power investments held for sale	(49)	Anticipated sales of investments
Net gain on domestic power investment sales [3]	7	Sales of power investments
Other	2	
Total	$ 124	
2003		
Gain on sale of interests in GulfTerra[4]	$ 266	Sale of various investment interests in GulfTerra
Chaparral Investors (Electron)	(207)	Decline in the investment s fair value based on developments in our power business and the power industry
Milford power facility[5]	(88)	Transfer of ownership to lenders
Dauphin Island Gathering/Mobile Bay Processing	(86)	Decline in the investments fair value based on the devaluation of the underlying assets
Bastrop Company	(43)	Decision to sell investment
Linden Venture, L.P.(East Coast Power)	(22)	Sale of investment in East Coast Power
Other investments	4	
Total	$ (176)	
2002 (Restated)		
CAPSA/CAPEX	$ (262)	Weak economic conditions in Argentina
EPIC Australia	(141)	Regulatory difficulties and the decision to discontinue further capital investment
CE Generation	(74)	Sale of investment
Aux Sable NGL	(47)	Sale of investment
Agua del Cajon	(24)	Weak economic conditions in Argentina
PPN	(41)	Loss of economic fuel supply and payment default
Meizhou Wan Generating	(7)	Weak economic conditions in China
Other investments	(16)	
Total	$ (612)	

(1) In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we sold to affiliates of Enterprise substantially all of our interests in GulfTerra. See further discussion of GulfTerra beginning on page F-112.

(2) Includes impairments of our investments in Korea Independent Energy Corporation, Meizhou Wan Generating, Habibullah Power, Saba Power Company and several other foreign power investments.

(3) Includes a loss on the sale of Bastrop Company and gains on the sale of several other domestic investments.

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(4) In 2003, we sold 50 percent of the equity of our consolidated subsidiary that holds our 1 percent general partner interest. This was recorded as minority interest in our balance sheet.

(5) In December 2003, we transferred our ownership interest in Milford to its lenders in order to terminate all of our obligations associated with Milford.

Below is summarized financial information of our proportionate share of unconsolidated affiliates. This information includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. We received distributions and dividends of $358 million and $398 million in 2004 and 2003, which includes $23 million and $53 million of returns of capital, from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $15 million, $119 million and $26 million in 2004, 2003 and 2002 and total assets of $734 million and $1.1 billion as of December 31, 2004 and 2003.

	Year Ended December 31,		
	2004	2003	2002
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$ 2,211	$ 3,360	$ 2,486
Operating expenses	1,485	2,309	1,632
Income from continuing operations	388	519	422
Net income	388	520	445

	December 31,	
	2004	2003
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 1,270	$ 1,024
Non-current assets	5,243	8,001
Short-term debt	250	1,169
Other current liabilities	488	645
Long-term debt	2,044	1,892
Other non-current liabilities	779	1,703
Minority interest	73	71
Equity in net assets	2,879	3,545

Below is summarized financial information of GulfTerra (in millions):

	Nine months ended September 30, 2004	Year Ended December 31, 2003	Year ended December 31, 2002
	(Unaudited)		

Operating results data:			
Net sales or gross revenues	$ 677	$ 871	$ 457
Operating expenses	432	557	297
Income from continuing operations	155	161	93
Net income	155	163	98

	As of September 30, 2004 (Unaudited)	As of December 31, 2003
Financial position data:		
Current assets	$ 230	$ 209
Noncurrent assets	3,167	3,113
Current liabilities	200	209
Noncurrent liabilities	1,921	1,860
Equity in net assets	1,276	1,253

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The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates:

	2004	2003	2002
		(In millions)	
Operating revenue	$ 218	$ 216	$ 65
Other revenue management fees	4	13	192
Cost of sales	102	106	178
Reimbursement for operating expenses	97	140	186
Other income	8	10	18
Interest income	8	11	30
Interest expense		2	42

Chaparral and Gemstone

As of December 31, 2002, we held equity investments in Chaparral and Gemstone. During 2003, we acquired the remaining third party equity interests and all of the voting rights in both of these entities. As discussed in Note 2, on page F-56, we consolidated Chaparral effective January 1, 2003 and Gemstone effective April 1, 2003.

GulfTerra

Prior to the sale of our interests in GulfTerra on September 30, 2004, our Field Services segment managed GulfTerra s daily operations and performed all of GulfTerra s administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributed to our income through our general partner interest and our ownership of common and preference units. We did not have any loans to or from GulfTerra.

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge to form the second largest publicly traded energy partnership in the U.S. On July 29, 2004, GulfTerra s unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004. In January 2005, we sold our remaining 9.9 percent interest in the two percent general partner of Enterprise and approximately 13.5 million common units in Enterprise 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.

In the December 2003 sales transactions, specific evaluation procedures were instituted to ensure that they were in the best interests of us and the partnership and were based on fair values. These procedures required our Board of Directors to evaluate and approve, as appropriate, each transaction with GulfTerra. In addition, a special committee comprised of the GulfTerra general partner s independent directors evaluated the transactions on GulfTerra s behalf. Both boards engaged independent financial advisors to assist with the evaluation and to opine on its fairness.

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Below is a detail of the gains or losses recognized in earnings from unconsolidated affiliates on transactions related to GulfTerra/Enterprise and other significant transactions during 2002, 2003, and 2004:

Transaction	Proceeds	Realized Gain/(Loss)
	(In millions)	
2002		
Sold San Juan Basin gathering, treating, and processing assets and Texas & New Mexico midstream assets to GulfTerra[1]	$ 1,501	$ 210
2003		
Sold 9.9% of our 1% general partner interest in GulfTerra to Goldman Sachs	88	
Repurchased the 9.9% interest from Goldman Sachs[2]	(116)	(28)
Redeemed series B preference units	156	(11)
Released from obligation in 2021 to purchase Chaco facility[3]	(10)	67
Sold 50% general partnership interest in GulfTerra to Enterprise[4]	425	297
Other GulfTerra common unit sales	23	8
2004		
Sold our interest in the general partner of GulfTerra, 2.9 million common units and 10.9 million series C units in GulfTerra to Enterprise[5][6]	951	507

(1) We received $955 million of cash, Series C units in GulfTerra with a value of $356 million, and an interest in a production field with a value of $190 million. We recorded an additional $74 million liability and related loss in 2003 for future pipeline integrity costs related to the transmission assets, for which we agreed to reimburse GulfTerra through 2006.

(2) We paid $92 million in cash and transferred GulfTerra common units with a book value of $19 million to Goldman Sachs in December 2003. We also paid $5 million of miscellaneous expenses related to the repurchase.

(3) We satisfied our obligation to GulfTerra through the transfer of communications assets with a book value of $10 million.

(4) The cash flows were reflected in our 2003 cash flow statement as an investing activity and $84 million of the proceeds were reflected as minority interest on our balance sheet. We also agreed to pay $45 million to Enterprise through 2006.

(5) We received $870 million in cash and a 9.9 percent interest in the general partner of the combined organization, Enterprise Products GP, with a fair value of $82 million. We also exchanged our remaining GulfTerra common units for 13.5 million Enterprise common units.

(6) As a result of the Enterprise transaction, we also recorded a $480 million impairment of the goodwill in loss on long-lived assets on our income statement associated with our Field Services segment. In addition, we sold South Texas assets to Enterprise for total proceeds of $156 million and a loss of $11 million included in our loss on long-lived assets.

Prior to the sale of our interests in GulfTerra to Enterprise in September 2004, a subsidiary in our Field Services segment served as the general partner of GulfTerra, a publicly traded master limited partnership. We had the following interests in GulfTerra (Enterprise effective September 30, 2004) as of December 31:

	2004	2003
	Ownership	Ownership

	Book Value (In millions)	(Percent)	Book Value (In millions)	(Percent)
One Percent General Partner[1]	$ 82	9.9	$ 194	100.0
Common Units	175	3.7	251	17.8
Series C Units			335	100.0
Total	$ 257		$ 780	

(1) We had $181 million of indefinite-lived intangible assets related to our general partner interest as of December 31, 2003. We also have $96 million recorded as minority interest related to the effective general partnership interest acquired by Enterprise in December 2003. This reduced our effective ownership interest in the general partner to 50 percent. Both of these were disposed of in the Enterprise sales described above.

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During each of the three years ended December 31, 2004, we conducted the following transactions with GulfTerra:

	2004	2003	2002
		(In millions)	
Revenues received from GulfTerra			
Field Services	$ 2	$ 5	$ 1
Marketing and Trading	26	28	19
Production			3
	$ 28	$ 33	$ 23
Expenses paid to GulfTerra			
Field Services	$ 84	$ 75	$ 97
Marketing and Trading	20	30	93
Production	9	9	9
	$ 113	$ 114	$ 199
Reimbursements received from GulfTerra			
Field Services	$ 71	$ 91	$ 60

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $103 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso. As a consequence of economic conditions described above, combined with the high prices on imported fuels and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales which may affect CEPP s ability to operate. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments may occur.

Berkshire Power Project. We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. We supply natural gas to Berkshire under a fuel management agreement. Berkshire has the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million, if Berkshire does not have available cash to meet its debt service requirements. Berkshire has delayed a total of $46 million of its fuel payments, including $8 million of interest, under this agreement as of December 31, 2004. During 2002, Berkshire s lenders asserted that Berkshire was in default on its loan agreement, and these issues remain unresolved. Based on the uncertainty surrounding these negotiations and Berkshire s inability to generate adequate future cash flow, we recorded losses of $10 million and $28 million in 2004 and 2003 associated with the amounts due to us under the fuel supply agreement.

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For contingent matters that could impact our investments in Brazil, see Note 17, on page F-87.

For a discussion of non-recourse project financing, see Note 15, on page F-79.

Duke Litigation. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus) has filed suit against Duke Energy LNG Sales, Inc (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. Duke has filed in federal court an amended counter claim joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke s motion, which is currently pending before the court. An unfavorable outcome on this matter could impact the value of our investment in Citrus.

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REPORT OF MANAGEMENT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Evaluation of Disclosure Controls and Procedures

As of December 31, 2004, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, our CEO and CFO concluded that as a result of the material weaknesses discussed below, our disclosure controls and procedures were not effective as of December 31, 2004. Because of these material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the year ended December 31, 2004, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Management s Report on Internal Control Over Financial Reporting (as restated)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including the CEO and CFO, we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, we used the criteria established in *Internal Control Integrated Framework* issued by the *Committee of Sponsoring Organizations of the Treadway Commission (COSO).*

As of December 31, 2004, we did not maintain effective controls over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. A specific description of these control deficiencies, which we concluded are material weaknesses that existed as of December 31, 2004, is discussed below. A material weakness is a control deficiency, or combination of control deficiencies, that results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

(1) *Access to Financial Application Programs and Data.* At December 31, 2004, we did not maintain effective controls over access to financial application programs and data at each of our operating segments. Specifically, we identified internal control deficiencies with respect to inadequate design of and compliance with our security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and a lack of independent monitoring of access to various systems by our information technology staff, as well as certain users that require unrestricted security access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of our financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, operating expenses, risk management assets and liabilities, and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that

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would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

(2) *Account Reconciliations.* At December 31, 2004, we did not maintain effective controls over the preparation and review of account reconciliations related to accounts such as prepaid insurance, accounts receivable, other assets and liabilities and taxes other than income taxes. Specifically, we found various instances in our Power and Marketing and Trading businesses where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. We also found instances within the company where accounts were not being reconciled and reviewed by individuals with adequate accounting experience and training. These control deficiencies resulted in adjustments impacting the fourth quarter 2004 financial information. Furthermore, these control deficiencies could result in a misstatement to the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

(3) *Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities.* At December 31, 2004, we did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. We identified control deficiencies related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment amounts, and accounting for divestiture of assets. These control deficiencies resulted in a) the restatement of our 2002 consolidated financial statements b) the restatement of our 2003 consolidated financial statements and restated 2003 fourth quarter information as described in the fifth paragraph of Note 1 as previously reported in our April 8, 2005 Form 10-K/A, c) the restatement of our 2003 and 2004 consolidated financial statements and restated 2003 fourth quarter and 2004 first, second and fourth quarter financial information as described in the sixth paragraph of Note 1, beginning on page F-44, and d) adjustments to the consolidated financial statements for the fourth quarter of 2004. Furthermore, these control deficiencies could result in a misstatement in the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Because of the material weaknesses described above, management has concluded that, as of December 31, 2004, we did not maintain effective internal control over financial reporting, based on the criteria established in *Internal Control Integrated Framework* issued by the COSO.

Management previously concluded that the Company did not maintain effective internal control over financial reporting as of December 31, 2004, because of the material weaknesses described in paragraphs (1), (2) and (3) above. In connection with the restatements of the Company s consolidated financial statements described in the fifth paragraph of Note 1, beginning on page F-44, to the consolidated financial statements, management has determined that the restatement was an additional effect of the material weaknesses described in item (3) above. Additionally, in connection with the restatement of the Company s consolidated financial statements described in the sixth paragraph of Note 1, beginning on page F-44, to the consolidated financial statements, management has determined that the restatement was an additional effect of the material weaknesses described in 3 above. Accordingly, these restatements do not affect the previous conclusion stated in our report on internal control over financial reporting.

Management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting

Changes Implemented Through December 31, 2004. During the course of 2004, management, with the oversight of our Audit Committee, devoted considerable effort to remediating deficiencies and to making

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improvements in our internal control over financial reporting. These improvements include the following enhancements in our internal controls over financial reporting:

Improving in the area of estimating oil and gas reserves, including changes in the composition of our Board of Directors and management by adding persons with greater experience in the oil and gas industry, creating a centralized reserve reporting function and internal committee that provides oversight of the reporting function, continuing the use of third party reserve engineering firms to perform an independent assessment of our proved reserves, and enhancing documentation with regard to the procedures and controls for recording proved reserves;

Implementing changes to our systems and procedures to segregate responsibilities for manual journal entry preparation and procurement activities; and

Implementing formal training to educate appropriate personnel on management s responsibilities mandated by the Sarbanes Oxley Act, Section 404, the components of the internal control framework on which we rely and its relationship to our core values.

Changes in 2005. Since December 31, 2004, we have taken action to correct the control deficiencies that resulted in the material weaknesses described in our report above including implementing monitoring controls in our information technology areas over users who require unrestricted access to perform their job responsibilities and formalizing and issuing a company-wide account reconciliation policy and providing training on the appropriate application of such policy. Other remedial actions have also been identified and are in the process of being implemented.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
El Paso Corporation:

We have completed an integrated audit of El Paso Corporation s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements and Financial Statement Schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1, the Company has restated its 2002, 2003 and 2004 consolidated financial statements.

As discussed in the notes to the consolidated financial statements, the Company adopted FASB Financial Interpretation No. 46, *Consolidation of Variable Interest Entities* on January 1, 2004; FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* on July 1, 2004; Statement of Financial Accounting Standards (SFAS) No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; SFAS No. 143, *Accounting for Asset Retirement Obligations* and SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* on January 1, 2003; SFAS No. 141, *Business Combinations,* SFAS No. 142, *Goodwill and Other Intangible Assets* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions; applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* on July 1, 2002 and EITF Issue No. 02-03, *Accounting for the Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2*, on October 1, 2002.

Internal Control Over Financial Reporting

Also, we have audited management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing on pages F-116 through F-118, that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, because the Company did not maintain effective controls over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. Management s assessment was based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management s assessment. At December 31, 2004, the Company did not maintain effective control over (1) access to financial applications programs and data, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. A specific description of these control deficiencies which management concluded are material weaknesses, that existed at December 31, 2004, is discussed below.

1. *Access to Financial Application Programs and Data.* At December 31, 2004, the Company did not maintain effective controls over access to financial application programs and data at each of its operating segments. Internal control deficiencies were identified with respect to inadequate design of and compliance with security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and lack of independent monitoring of access to various systems by information technology staff, as well as certain users with accounting and reporting responsibilities who also have security administrator access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of the Company s financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, price risk management assets and liabilities, and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

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2. *Account Reconciliations.* At December 31, 2004, the Company did not maintain effective controls over the preparation and review of account reconciliations related to accounts such as prepaid insurance, accounts receivable, other assets and taxes other than income taxes. Specifically, instances were identified in the Power and Marketing and Trading businesses where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. Instances were also noted where accounts were not being reconciled and reviewed by individuals with adequate accounting experience and training. These control deficiencies resulted in adjustments impacting the fourth quarter of 2004 financial statements. Furthermore, these control deficiencies could result in a misstatement of the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

3. *Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities.* At December 31, 2004, the Company did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. Control deficiencies were identified related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment of long-lived assets, and accounting for divestitures. These control deficiencies resulted in (a) the restatement of the 2002 consolidated financial statements, (b) the restatement of the 2003 consolidated financial statements and related 2003 fourth quarter financial information as described in the fifth paragraph of Note 1 as previously reported in the Company s April 8, 2005 Form 10-K/A, (c) the restatement of the 2003 and 2004 consolidated financial statements and related 2003 fourth quarter and 2004 first, second and fourth quarter information as described in the sixth paragraph of Note 1 as reported in this Registration Statement on Form S-1 and (d) adjustments to the financial statements for the fourth quarter of 2004. Furthermore, these control deficiencies could result in a material misstatement in the aforementioned accounts that would result in a misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly these control deficiencies constitute a material weakness.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and our opinion regarding the effectiveness of the Company s internal control over financial reporting does not affect our opinion on those consolidated financial statements.

In our opinion, management s assessment that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by COSO. Also, in our opinion, because of the effects of the material weaknesses described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control Integrated Framework* issued by COSO.

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Management and we previously concluded that the Company did not maintain effective internal control over financial reporting as of December 31, 2004 because of the material weaknesses described in items 1, 2 and 3 above. In connection with the restatement of the Company s consolidated financial statements described in the fifth paragraph of Note 1 to the consolidated financial statements, management has determined that the restatement was an additional effect of the material weakness described in item 3 above. Additionally, in connection with the restatement of the Company s consolidated financial statements described in the sixth paragraph of Note 1 to the consolidated financial statements, management has determined that the restatement was an additional effect of the material weaknesses described in item 3 above. Accordingly, these restatements did not affect management s assessment or our opinions on internal control over financial reporting.

PricewaterhouseCoopers LLP
Houston, Texas
March 25, 2005, except for the
restatement described in the fifth paragraph
of Note 1 to the consolidated financial
statements and the matter described in the
penultimate paragraph of Management s Report on
Internal Control over Financial Reporting, as to
which the date is April 8, 2005, and except for
the restatement described in the sixth paragraph
of Note 1 to the consolidated financial
statements and the matters described in the
penultimate paragraph of Management s Report on
Internal Control Over Financial Reporting, as to
which the date is June 15, 2005

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Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(Restated)[2]	(Restated)[2]		(Restated)[2]	
	(In millions, except per common share amounts)				
2004					
Operating revenues	$ 1,557	$ 1,524	$ 1,429	$ 1,364	$ 5,874
Loss on long-lived assets	238	17	582	271	1,108
Operating income (loss)	189	370	(355)	(14)	190
Income (loss) from continuing operations	$ (119)	$ 34	$ (202)	$ (546)	$ (833)
Discontinued operations, net of income taxes[1]	(77)	(29)	(12)	4	(114)
Net income (loss)	$ (196)	$ 5	$ (214)	$ (542)	$ (947)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	$ (0.19)	$ 0.05	$ (0.31)	$ (0.86)	$ (1.30)
Discontinued operations, net of income taxes	(0.12)	(0.04)	(0.02)	0.01	(0.18)
Net income (loss)	$ (0.31)	$ 0.01	$ (0.33)	$ (0.85)	$ (1.48)

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
				(Restated)[2]	
	(In millions, except per common share amounts)				
2003					
Operating revenues	$ 1,828	$ 1,569	$ 1,714	$ 1,557	$ 6,668
Loss on long-lived assets	14	395	54	397	860
Western Energy Settlement		123	(20)	1	104
Operating income (loss)	264	(272)	481	(68)	405
Income (loss) from continuing operations	$ (207)	$ (297)	$ 65	$ (156)	$ (595)
Discontinued operations, net of income taxes[1]	(215)	(939)	(41)	(84)	(1,279)
Cumulative effect of accounting changes, net of income taxes	(9)				(9)

Net income (loss)	$ (431)	$ (1,236)	$ 24	$ (240)	$ (1,883)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	$ (0.34)	$ (0.50)	$ 0.11	$ (0.26)	$ (0.99)
Discontinued operations, net of income taxes	(0.36)	(1.57)	(0.07)	(0.14)	(2.14)
Cumulative effect of accounting changes, net of income taxes	(0.02)				(0.02)
Net income (loss)	$ (0.72)	$ (2.07)	$ 0.04	$ (0.40)	$ (3.15)

(1) Our petroleum markets operations, our Canadian and certain other international natural gas and oil production operations, and our coal mining operations are classified as discontinued operations (See Note 3, on page F-60, for further discussion).

(2) The table below reflects the amounts we originally reported in our Form 10-K filed on March 28, 2005. Items indicated with a (*) were not restated. See Note 1, on page F-44, to the consolidated financial statements for a further discussion of these restatements and the impact on each annual period.

	Quarters Ended			
	March 31, 2004	**June 30, 2004**	**December 31, 2004**	**December 31, 2003**
	(In millions, except per common share amounts)			
Loss on long-lived assets	$ 222	*	*	*
Operating income (loss)	205	*	*	*
Income (loss) from continuing operations	(97)	$ 45	$ (548)	$ (84)
Discontinued operations, net of income taxes	(109)	*	*	(201)
Net income (loss)	(206)	16	(544)	(285)
Basic and diluted earnings per common share				
Income (loss) from continuing operations	$ (0.15)	$ 0.07	*	$ (0.14)
Discontinued operations, net of income taxes	(0.17)	*	*	(0.33)
Net income (loss)	$ (0.32)	$ 0.03	*	$ (0.47)

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Supplemental Natural Gas and Oil Operations (Unaudited)

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, we have onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. All of our proved reserves are in the United States and Brazil. We have excluded information relating to our natural gas and oil operations in Canada, Indonesia and Hungary from the following disclosures. We classified these operations as discontinued operations beginning in the second quarter of 2004 based on our decision to exit these operations.

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

	United States	Brazil	Worldwide
2004			
Natural gas and oil properties:			
Costs subject to amortization[1]	$ 14,211	$ 337	$ 14,548
Costs not subject to amortization	308	112	420
	14,519	449	14,968
Less accumulated depreciation, depletion and amortization	11,130	138	11,268
Net capitalized costs	$ 3,389	$ 311	$ 3,700
FAS143 abandonment liability	$ 252	$ 4	$ 256
2003			
Natural gas and oil properties:			
Costs subject to amortization[1]	$ 14,052	$ 146	$ 14,198
Costs not subject to amortization	371	117	488
	14,423	263	14,686
Less accumulated depreciation, depletion and amortization	11,216	58	11,274
Net capitalized costs	$ 3,207	$ 205	$ 3,412
FAS 143 abandonment liability	$ 210	$	$ 210

(1) As of January 1, 2003, we adopted SFAS No. 143, which is further discussed in Note 1, on page F-44. Included in our costs subject to amortization at December 31, 2004 and 2003 are SFAS No. 143 asset values of $154 million and $124 million for the United States and $3 million and $0.2 million for Brazil.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

	United States	Brazil	Worldwide

2004			
Property acquisition costs			
Proved properties	$ 33	$ 69	$ 102
Unproved properties	32	3	35
Exploration costs[1]	185	25	210
Development costs[1]	395	1	396
Costs expended in 2004	645	98	743
Asset retirement obligation costs	30	3	33
Total costs incurred	$ 675	$ 101	$ 776

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	United States	Brazil	Worldwide
2003			
Property acquisition costs			
Proved properties	$ 10	$	$ 10
Unproved properties	35	4	39
Exploration costs[1]	467	95	562
Development costs[1]	668		668
Costs expended in 2003	1,180	99	1,279
Asset retirement obligation costs[2]	124		124
Total costs Incurred	$ 1,304	$ 99	$ 1,403
2002			
Property acquisition costs			
Proved properties	$ 362	$	$ 362
Unproved properties	29	9	38
Exploration costs	524	45	569
Development costs	1,242		1,242
Total costs incurred	$ 2,157	$ 54	$ 2,211

(1) Excludes approximately $110 million and $130 million that was paid in 2004 and 2003 under net profits agreements described beginning on page F-129.

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1, on page F-44. The cumulative effect of adopting SFAS No. 143 was $3 million.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $44 million, $58 million, and $76 million and capitalized interest of $22 million, $19 million and $10 million for the years ended December 31, 2004, 2003 and 2002.

In our January 1, 2005 reserve report, the amounts estimated to be spent in 2005, 2006 and 2007 to develop our worldwide booked proved undeveloped reserves are $182 million, $251 million and $218 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2004, pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2004	Costs Excluded for Years Ended December 31			Cumulative Balance December 31, 2001
		2004	2003	2002	
Worldwide[1][2]					
Acquisition	$ 209	$ 76	$ 51	$ 61	$ 21

Exploration	178	62	92	18	6
Development	33	1	3	27	2
	$ 420	$ 139	$ 146	$ 106	$ 29

(1) Includes operations in the United States and Brazil.

(2) Includes capitalized interest of $20 million, $6 million, and less than $1 million for the years ended December 31, 2004, 2003, and 2002.

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Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2005 through 2008. Our total amortization expense per Mcfe for the United States was $1.84, $1.40, and $1.05 in 2004, 2003, and 2002 and $2.02 for Brazil in 2004. We had no production in Brazil during 2003 and 2002. Included in our worldwide depreciation, depletion, and amortization expense is accretion expense of $0.08/Mcfe and $0.06/Mcfe for 2004 and 2003 attributable to SFAS No. 143 which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil, and condensate, and changes in these reserves at December 31, 2004 are presented below. 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 interest 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 NGL for total natural gas equivalents of 145,507 MMcfe, all net to our ownership interests.

	Natural Gas (in Bcf)		
	United States	**Brazil**	**Worldwide**
Net proved developed and undeveloped reserves[1]			
January 1, 2002	2,799		2,799
Revisions of previous estimates	(155)		(155)
Extensions, discoveries and other	829		829
Purchases of reserves in place	142		142
Sales of reserves in place	(657)		(657)
Production	(470)		(470)
December 31, 2002	2,488		2,488
Revisions of previous estimates	(24)		(24)
Extensions, discoveries and other	405		405
Purchases of reserves in place	2		2
Sales of reserves in place[2]	(471)		(471)
Production	(339)		(339)
December 31, 2003	2,061		2,061
Revisions of previous estimates	(172)		(172)
Extensions, discoveries and other	79	38	117
Purchases of reserves in place	15	38	53
Sales of reserves in place[2]	(21)		(21)
Production	(238)	(7)	(245)
December 31, 2004	1,724	69	1,793
Proved developed reserves			

December 31, 2002	1,799		1,799
December 31, 2003	1,428		1,428
December 31, 2004	1,287	54	1,341

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 20,729 MMcf and 28,779 MMcf of natural gas conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page F-129.

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	Oil and Condensate (in MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	45,153		45,153
Revisions of previous estimates	1,552		1,552
Extensions, discoveries and other	7,921		7,921
Purchases of reserves in place	62		62
Sales of reserves in place	(3,754)		(3,754)
Production	(12,580)		(12,580)
December 31, 2002	38,354		38,354
Revisions of previous estimates	895		895
Extensions, discoveries and other	5,000	20,543	25,543
Purchases of reserves in place	5		5
Sales of reserves in place[2]	(4,328)		(4,328)
Production	(7,555)		(7,555)
December 31, 2003	32,371	20,543	52,914
Revisions of previous estimates	(999)	252	(747)
Extensions, discoveries and other	2,214	1,848	4,062
Purchases of reserves in place		1,848	1,848
Sales of reserves in place[2]	(1,276)		(1,276)
Production	(4,979)	(320)	(5,299)
December 31, 2004	27,331	24,171	51,502
Proved developed reserves			
December 31, 2002	28,554		28,554
December 31, 2003	22,821		22,821
December 31, 2004	19,641	2,613	22,254

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual agreements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 1,276 MBbl and 1,098 MBbl of liquids conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page F-129.

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	NGL (in MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	28,874		28,874
Revisions of previous estimates	(2,289)		(2,289)
Extensions, discoveries and other	6,820		6,820
Purchases of reserves in place			
Sales of reserves in place	(7,916)		(7,916)
Production	(3,882)		(3,882)
December 31, 2002	21,607		21,607
Revisions of previous estimates	(2,717)		(2,717)
Extensions, discoveries and other	1,795		1,795
Purchases of reserves in place	27		27
Sales of reserves in place[2]	(504)		(504)
Production	(4,223)		(4,223)
December 31, 2003	15,985		15,985
Revisions of previous estimates	724		724
Extensions, discoveries and other	58		58
Purchases of reserves in place			
Sales of reserves in place[2]	(47)		(47)
Production	(3,519)		(3,519)
December 31, 2004	13,201		13,201
Proved developed reserves			
December 31, 2001	17,526		17,526
December 31, 2002	14,088		14,088
December 31, 2003	11,943		11,943

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual agreements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 47 MBbl and 194 MBbl of NGL conveyed to third parties under net profits agreements in 2004 and 2003 as described below.

During 2004, we had approximately 174 Bcfe of negative reserve revisions in the United States that were largely performance-driven. Our reserve revisions were primarily concentrated onshore in our coal bed methane operations and offshore in the Gulf of Mexico:

Onshore. The onshore region recorded 71 Bcfe of negative reserve revisions. All of the negative reserve revisions are related to performance results from producing wells or the recent drilling program coupled with the related impact on booked proven undeveloped locations. In certain areas of the Arkoma and Black Warrior Basins, wells drilled in late 2003 had positive initial results; however, subsequent drilling and additional production history resulted in 70 Bcfe of negative revisions. In the Holly Field of North Louisiana, 14 Bcfe of reserves were revised downward as a

result of production performance. These negative revisions were offset by better-than-anticipated performance in the Rockies and other Arklatex fields, resulting in positive reserve revisions of 13 Bcfe.

Texas Gulf Coast. The Texas Gulf Coast region recorded 26 Bcfe of negative reserve revisions. The negative revisions were comprised of approximately 7 Bcfe of performance revisions to proved producing wells, approximately 6 Bcfe due to mechanical failures in five wells, and approximately 13 Bcfe due to lower-than-expected results from the 2004 development drilling program.

Offshore. The offshore region recorded 77 Bcfe of negative reserve revisions in the Gulf of Mexico. Approximately 10 Bcfe of the revisions is a result of mechanical failures, and approximately 25 Bcfe is due to

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producing well performance. The remaining 42 Bcfe resulted from the drilling of development wells and adjustments to proved undeveloped reserves as a result of production performance in offsetting locations.

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. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2004. However in January 2005, we announced two acquisitions in east Texas and south Texas for $211 million. In March 2005, we acquired the interest of one of the parties in our net profits interest drilling program for $62 million. These acquisitions added properties with approximately 139 Bcfe of existing proved reserves and 52 MMcfe/d of current production.

In 2003, we entered into agreements to sell interests in a maximum of 124 wells to Lehman Brothers and a subsidiary of Nabors Industries. As these wells are developed, Lehman and Nabors will pay 70 percent of the drilling and development costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, Lehman and Nabors receive an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 70 percent of the aggregate net profits of all wells until they have recovered 117.5 percent of their aggregate investment. Upon this recovery, the net profits interest will convert to a 2 percent overriding royalty interest in the wells for the remainder of the well s productive life. We do not guarantee a return or the recovery of Lehman and Nabor s costs. All parties to the agreement have the right to cease participation in the agreement at any time, at which time Lehman or Nabors will continue to receive its net profits interest on wells previously started, but will relinquish its right to participate in any future wells. During 2004, we sold interests in 54 wells and total proved reserves of 20,729 MMcf of natural gas and 1,323 MBbl of oil and natural gas liquids. They have paid $110 million of drilling and development costs and were paid $152 million of the revenues net of $11 million of expenses associated with these wells for the year ended December 31, 2004. In March 2005, we acquired all of the interests held by the Lehman subsidiary for $62 million.

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Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	United States	Brazil	Worldwide
2004			
Net Revenues			
Sales to external customers	$ 518	$ 27	$ 545
Affiliated sales	1,137	(1)	1,136
Total	1,655	26	1,681
Production costs[1]	(210)		(210)
Depreciation, depletion and amortization[2]	(530)	(18)	(548)
	915	8	923
Income tax (expense) benefit	(333)	(3)	(336)
Results of operations from producing activities	$ 582	$ 5	$ 587
2003			
Net Revenues			
Sales to external customers	$ 191	$	$ 191
Affiliated sales	1,868		1,868
Total	2,059		2,059
Production costs[1]	(229)		(229)
Depreciation, depletion and amortization[2]	(576)		(576)
Ceiling test charges		(5)	(5)
	1,254	(5)	1,249
Income tax (expense) benefit	(449)	2	(447)
Results of operations from producing activities	$ 805	$ (3)	$ 802
2002			
Net Revenues			
Sales to external customers	$ 134	$	$ 134
Affiliated sales	1,677		1,677
Total	1,811		1,811
Production costs[1]	(284)		(284)
Depreciation, depletion and amortization	(599)		(599)
Gain on long-lived assets	2		2
	930		930
Income tax (expense) benefit	(327)		(327)
Results of operations from producing activities	$ 603	$	$ 603

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

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1, on page F-44. Our depreciation, depletion and amortization includes accretion expense for SFAS 143 abandonment liabilities of $23 million primarily for the United States for both 2004 and 2003.

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The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves at December 31 is as follows (in millions):

	United States	Brazil	Worldwide
2004			
Future cash inflows[1]	$ 11,895	$ 1,077	$ 12,972
Future production costs	(3,585)	(135)	(3,720)
Future development costs	(1,234)	(274)	(1,508)
Future income tax expenses	(1,184)	(141)	(1,325)
Future net cash flows	5,892	527	6,419
10% annual discount for estimated timing of cash flows	(2,004)	(219)	(2,223)
Standardized measure of discounted future net cash flows	$ 3,888	$ 308	$ 4,196
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 3,907	$ 305	$ 4,212
2003			
Future cash inflows[1]	$ 13,302	$ 588	$ 13,890
Future production costs	(3,025)	(65)	(3,090)
Future development costs	(1,325)	(236)	(1,561)
Future income tax expenses	(1,695)	(75)	(1,770)
Future net cash flows	7,257	212	7,469
10% annual discount for estimated timing of cash flows	(2,449)	(128)	(2,577)
Standardized measure of discounted future net cash flows	$ 4,808	$ 84	$ 4,892
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,759	$ 84	$ 4,843
2002			
Future cash inflows[1]	$ 12,847	$	$ 12,847
Future production costs	(2,924)		(2,924)
Future development costs	(1,361)		(1,361)
Future income tax expenses	(1,960)		(1,960)
Future net cash flows	6,602		6,602
10% annual discount for estimated timing of cash flows	(2,293)		(2,293)
Standardized measure of discounted future net cash flows	$ 4,309	$	$ 4,309
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,266	$	$ 4,266

(1) United States excludes $1 million, $104 million and $85 million of future net cash outflows attributable to hedging activities in the years 2004, 2003 and 2002. Brazil excludes $5 million of future net cash outflows attributable to hedging activities in 2004.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $6.22 per MMbtu for natural gas and $43.45 per barrel of oil at December 31, 2004. Adjustments for transportation and other charges resulted in a net price of $5.99 per Mcf of gas, $42.11 per barrel of oil and $32.13 per barrel of NGL at December 31, 2004. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

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We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions, capital availability, and corporate investment criteria.

The following are the principal sources of change in the worldwide standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,[1],[2]		
	2004	2003	2002
	(In Millions)		
Sales and transfers of natural gas and oil produced net of production costs	$ (1,470)	$ (1,829)	$ (1,526)
Net changes in prices and production costs	29	1,586	3,301
Extensions, discoveries and improved recovery, less related costs	268	1,105	1,561
Changes in estimated future development costs	4	(16)	17
Previously estimated development costs incurred during the period	156	220	275
Revision of previous quantity estimates	(453)	(94)	(348)
Accretion of discount	568	526	275
Net change in income taxes	257	159	(934)
Purchases of reserves in place	114	5	284
Sale of reserves in place	(75)	(1,229)	(1,418)
Change in production rates, timing and other	(94)	150	93
Net change	$ (696)	$ 583	$ 1,580

[1] This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.
[2] Includes operations in the United States and Brazil.

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SCHEDULE II
EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2004, 2003 and 2002
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2004					
Allowance for doubtful accounts	$ 273	$ (48)	$ (22)[1]	$ (4)	$ 199
Valuation allowance on deferred tax assets	9	46[3]	(4)		51
Legal reserves	1,169	145	(655)[5]	(67)	592
Environmental reserves	412	17	(51)[5]	2	380
Regulatory reserves	13		(12)[5]		1
2003					
Allowance for doubtful accounts	$ 176	$ 18	$ (31)[1]	$ 110[2]	$ 273
Valuation allowance on deferred tax assets	72	4	(68)[3]	1	9
Legal reserves	1,031	180[4]	(43)[5]	1	1,169
Environmental reserves	389	8	(52)[5]	67[6]	412
Regulatory reserves	24	32	(43)[5]		13
2002					
Allowance for doubtful accounts	$ 117	$ 30	$ (14)[1]	$ 43[2]	$ 176
Valuation allowance on deferred tax assets	28	46[3]	(2)		72
Legal reserves	149	954[4]	(74)[5]	2	1,031
Environmental reserves	468	(3)	(63)	(13)	389
Regulatory reserves	34	48	(59)[5]	1	24

(1) Relates primarily to accounts written off.
(2) Relates primarily to receivables from trading counterparties, reclassified due to bankruptcy or declining credit that have been accounted for within our price risk management activities.
(3) Relates primarily to valuation allowances for deferred tax assets related to the Western Energy Settlement, foreign ceiling test charges, foreign asset impairments and net operating loss carryovers.
(4) Relates to our Western Energy Settlement of $104 million in 2003 and $899 million in 2002. In June 2004, we released approximately $602 million to the settling parties (including approximately $568 million from escrow) and correspondingly reduced our liability by this amount.
(5) Relates primarily to payments for various litigation reserves, including the Western Energy Settlement, environmental remediation reserves or revenue crediting and rate settlement reserves.
(6)

Relates primarily to liabilities previously classified in our petroleum discontinued operations, but reclassified as continuing operations due to our retention of these obligations.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
REPORT OF MANAGEMENT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Evaluation of Disclosure Controls and Procedures

MCV s management, including the President and Chief Executive Officer, and the Chief Financial Officer, Vice President and Controller, after evaluating the effectiveness of MCV s disclosure controls and procedures (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) or 15d-15(e)) as of the end of the period covered by this report, have concluded that based on the evaluation of these controls and procedures required by paragraph (b) of Exchange Act Rules 13a-15 or 15d-15, that MCV s disclosure controls and procedures were effective.

Management s Report on Internal Control Over Financial Reporting

MCV s management is responsible for establishing and maintaining an adequate system of internal control over financial reporting of MCV. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

MCV s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of MCV; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of MCV are being made only in accordance with authorizations of management and the Management Committee of MCV; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of MCV s assets that could have a material effect on the financial statements.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time. Our system contains self-monitoring mechanisms, and actions are taken to correct deficiencies as they are identified.

MCV management conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that MCV s system of internal control over financial reporting was effective as of December 31, 2004. MCV management s assessment of the effectiveness of MCV s internal control over financial reporting has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control Over Financial Reporting

There were no changes in MCV s internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Exchange Act Rules 13a-15 or 15d-15 that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PRICEWATERHOUSECOOPERS LLP

Report of Independent Registered Public Accounting Firm

To the Partners and the Management Committee of
Midland Cogeneration Venture Limited Partnership:

We have completed an integrated audit of Midland Cogeneration Venture Limited Partnership 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its December 31, 2003 and December 31, 2002 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, partners equity and cash flows present fairly, in all material respects, the financial position of the Midland Cogeneration Limited Partnership (a Michigan limited partnership) and its subsidiaries (MCV) at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the MCV s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As explained in Note 2 to the financial statements, effective April 1, 2002, Midland Cogeneration Venture Limited Partnership changed its method of accounting for derivative and hedging activities in accordance with Derivative Implementation Group (DIG) Issue C-16.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting appearing on page FA-1, that the MCV maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the MCV maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The MCV s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the MCV s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Detroit, Michigan
February 25, 2005

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31,
(In Thousands)

	2004	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 125,781	$ 173,651
Accounts and notes receivable related parties	54,368	43,805
Accounts receivable	42,984	38,333
Gas inventory	17,509	20,298
Unamortized property taxes	18,060	17,672
Derivative assets	94,977	86,825
Broker margin accounts, and prepaid gas costs and expenses	13,147	8,101
Total current assets	366,826	388,685
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment	2,466,944	2,463,931
Pipeline	21,432	21,432
Total property, plant and equipment	2,488,376	2,485,363
Accumulated depreciation	(1,062,821)	(991,556)
Net property, plant and equipment	1,425,555	1,493,807
OTHER ASSETS:		
Restricted investment securities held-to-maturity	139,410	139,755
Derivative assets non-current	24,337	18,100
Deferred financing costs, net of accumulated amortization of $18,498 and $17,285, respectively	6,467	7,680
Prepaid gas costs, spare parts deposit, materials and supplies	17,782	21,623
Total other assets	187,996	187,158
TOTAL ASSETS	$ 1,980,377	$ 2,069,650
LIABILITIES AND PARTNERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 82,693	$ 57,368
Gas supplier funds on deposit	19,613	4,517
Interest payable	47,738	53,009
Current portion of long-term debt	76,548	134,576
Total current liabilities	226,592	249,470
NON-CURRENT LIABILITIES:		

Long-term debt	942,097	1,018,645
Other	1,712	2,459
Total non-current liabilities	943,809	1,021,104
COMMITMENTS AND CONTINGENCIES (Notes 7 and 8)		
TOTAL LIABILITIES	1,170,401	1,270,574
PARTNERS EQUITY	809,976	799,076
TOTAL LIABILITIES AND PARTNERS EQUITY	$ 1,980,377	$ 2,069,650

The accompanying notes are an integral part of these statements.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	2004	2003	2002
OPERATING REVENUES:			
Capacity	$ 405,415	$ 404,681	$ 404,713
Electric	225,154	162,093	177,569
Steam	19,090	17,638	14,537
Total operating revenues	649,659	584,412	596,819
OPERATING EXPENSES:			
Fuel costs	413,061	254,988	255,142
Depreciation	88,712	89,437	88,963
Operations	18,769	16,943	16,642
Maintenance	13,508	15,107	12,666
Property and single business taxes	28,834	30,040	27,087
Administrative, selling and general	11,236	9,959	8,195
Total operating expenses	574,120	416,474	408,695
OPERATING INCOME	75,539	167,938	188,124
OTHER INCOME (EXPENSE):			
Interest and other income	5,460	5,100	5,555
Interest expense	(104,618)	(113,247)	(119,783)
Total other income (expense), net	(99,158)	(108,147)	(114,228)
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	(23,619)	59,791	73,896
Cumulative effect of change in method of accounting for derivative option contracts (to April 1, 2002) (Note 2)			58,131
NET INCOME (LOSS)	$ (23,619)	$ 59,791	$ 132,027

The accompanying notes are an integral part of these statements.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF PARTNERS EQUITY
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	General Partners	Limited Partners	Total
BALANCE, DECEMBER 31, 2001	$ 468,972	$ 82,740	$ 551,712
Comprehensive Income			
Net Income	114,947	17,080	132,027
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	33,311	4,950	38,261
Reclassification adjustments recognized in net income above	10,717	1,593	12,310
Total other comprehensive income	44,028	6,543	50,571
Total Comprehensive Income	158,975	23,623	182,598
BALANCE, DECEMBER 31, 2002	$ 627,947	$ 106,363	$ 734,310
Comprehensive Income			
Net Income	52,056	7,735	59,791
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	34,484	5,125	39,609
Reclassification adjustments recognized in net income above	(30,153)	(4,481)	(34,634)
Total other comprehensive income	4,331	644	4,975
Total Comprehensive Income	56,387	8,379	64,766
BALANCE, DECEMBER 31, 2003	$ 684,334	$ 114,742	$ 799,076
Comprehensive Income			
Net Loss	(20,563)	(3,056)	(23,619)
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period	62,292	9,256	71,548
Reclassification adjustments recognized in net income above	(32,239)	(4,790)	(37,029)
Total other comprehensive income	30,053	4,466	34,519
Total Comprehensive Income	9,490	1,410	10,900
BALANCE, DECEMBER 31, 2004	$ 693,824	$ 116,152	$ 809,976

The accompanying notes are an integral part of these statements.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (23,619)	$ 59,791	$ 132,027
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	89,925	90,792	90,430
Cumulative effect of change in accounting principle			(58,131)
(Increase) decrease in accounts receivable	(15,214)	(1,211)	48,343
(Increase) decrease in gas inventory	2,789	(732)	133
(Increase) decrease in unamortized property taxes	(388)	683	(1,730)
(Increase) decrease in broker margin accounts and prepaid expenses	(5,046)	(4,778)	31,049
(Increase) decrease in derivative assets	20,130	4,906	(20,444)
(Increase) decrease in prepaid gas costs, materials and supplies	3,841	(8,704)	1,376
Increase (decrease) in accounts payable and accrued liabilities	25,775	(712)	8,774
Increase in gas supplier funds on deposit	15,096	4,517	
Decrease in interest payable	(5,271)	(3,377)	(3,948)
Increase (decrease) in other non-current liabilities	(1,197)	311	(24)
Net cash provided by operating activities	106,821	141,486	227,855
CASH FLOWS FROM INVESTING ACTIVITIES:			
Plant modifications and purchases of plant equipment	(20,460)	(33,278)	(29,529)
Maturity of restricted investment securities held-to-maturity	674,553	601,225	377,192
Purchase of restricted investment securities held-to-maturity	(674,208)	(602,279)	(374,426)
Net cash used in investing activities	(20,115)	(34,332)	(26,763)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayment of financing obligation	(134,576)	(93,928)	(182,084)
Net cash used in financing activities	(134,576)	(93,928)	(182,084)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(47,870)	13,226	19,008
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	173,651	160,425	141,417
CASH AND EQUIVALENTS AT END OF PERIOD	$ 125,781	$ 173,651	$ 160,425

The accompanying notes are an integral part of these statements.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) The Partnership and Associated Risks

MCV was organized to construct, own and operate a combined-cycle, gas-fired cogeneration facility (the Facility) located in Midland, Michigan. MCV was formed on January 27, 1987, and the Facility began commercial operation in 1990.

In 1992, MCV had acquired the outstanding common stock of PVCO Corp., a previously inactive company. MCV and PVCO Corp. then entered into a partnership agreement to form MCV Gas Acquisition General Partnership (MCV GAGP) for the purpose of buying and selling natural gas on the spot market and other transactions involving natural gas activities. PVCO Corp. and MCV GAGP were dissolved on January 30, 2004 and July 2, 2004, respectively, due to inactivity.

The Facility has a net electrical generating capacity of approximately 1500 MW and approximately 1.5 million pounds of process steam capacity per hour. MCV has entered into three principal energy sales agreements. MCV has contracted to (i) supply up to 1240 MW of electric capacity (Contract Capacity) to Consumers Energy Company (Consumers) under the Power Purchase Agreement (PPA), for resale to its customers through 2025, (ii) supply electricity and steam to The Dow Chemical Company (Dow) through 2008 and 2015, respectively, under the Steam and Electric Power Agreement (SEPA) and (iii) supply steam to Dow Corning Corporation (DCC) under the Steam Purchase Agreement (SPA) through 2011. From time to time, MCV enters into other sales agreements for the sale of excess capacity and/or energy available above MCV s internal use and obligations under the PPA, SEPA and SPA. Results of operations are primarily dependent on successfully operating the Facility at or near contractual capacity levels and on Consumers ability to perform its obligations under the PPA. Sales pursuant to the PPA have historically accounted for over 90% of MCV s revenues.

The PPA permits Consumers, under certain conditions, to reduce the capacity and energy charges payable to MCV and/or to receive refunds of capacity and energy charges paid to MCV if the Michigan Public Service Commission (MPSC) does not permit Consumers to recover from its customers the capacity and energy charges specified in the PPA (the regulatory-out provision). Until September 15, 2007, however, the capacity charge may not be reduced below an average capacity rate of 3.77 cents per kilowatt-hour for the available Contract Capacity notwithstanding the regulatory-out provision. Consumers and MCV are required to support and defend the terms of the PPA.

The Facility is a qualifying cogeneration facility (QF) originally certified by the Federal Energy Regulatory Commission (FERC) under the Public Utility Regulatory Policies Act of 1978, as amended (PURPA). In order to maintain QF status, certain operating and efficiency standards must be maintained on a calendar-year basis and certain ownership limitations must be met. In the case of a topping-cycle generating plant such as the Facility, the applicable operating standard requires that the portion of total energy output that is put to some useful purpose other than facilitating the production of power (the Thermal Percentage) be at least 5%. In addition, the Facility must achieve a PURPA efficiency standard (the sum of the useful power output plus one-half of the useful thermal energy output, divided by the energy input (the Efficiency Percentage)) of at least 45%. If the Facility maintains a Thermal Percentage of 15% or higher, the required Efficiency Percentage is reduced to 42.5%. Since 1990, the Facility has achieved the applicable Thermal and Efficiency Percentages. For the twelve months ended December 31, 2004, the Facility achieved a Thermal Percentage of 15.6% and an Efficiency Percentage of 47.6%. The loss of QF status could, among other things, cause MCV to lose its rights under PURPA to sell power from the Facility to Consumers at Consumers avoided cost and subject MCV to additional federal and state regulatory requirements.

The Facility is wholly dependent upon natural gas for its fuel supply and a substantial portion of the Facility s operating expenses consist of the costs of natural gas. MCV recognizes that its existing gas contracts are not sufficient to satisfy the anticipated gas needs over the term of the PPA and, as such, no assurance can be given as to the availability or price of natural gas after the expiration of the existing gas contracts. In

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

addition, to the extent that the costs associated with production of electricity rise faster than the energy charge payments, MCV s financial performance will be negatively affected. The extent of such impact will depend upon the amount of the average energy charge payable under the PPA, which is based upon costs incurred at Consumers coal-fired plants and upon the amount of energy scheduled by Consumers for delivery under the PPA. However, given the unpredictability of these factors, the overall economic impact upon MCV of changes in energy charges payable under the PPA and in future fuel costs under new or existing contracts cannot accurately be predicted.

At both the state and federal level, efforts continue to restructure the electric industry. A significant issue to MCV is the potential for future regulatory denial of recovery by Consumers from its customers of above market PPA costs Consumers pays MCV. At the state level, the MPSC entered a series of orders from June 1997 through February 1998 (collectively the Restructuring Orders), mandating that utilities wheel third-party power to the utilities customers, thus permitting customers to choose their power provider. MCV, as well as others, filed an appeal in the Michigan Court of Appeals to protect against denial of recovery by Consumers of PPA charges. The Michigan Court of Appeals found that the Restructuring Orders do not unequivocally disallow such recovery by Consumers and, therefore, MCV s issues were not ripe for appellate review and no actual controversy regarding recovery of costs could occur until 2008, at the earliest. In June 2000, the State of Michigan enacted legislation which, among other things, states that the Restructuring Orders (being voluntarily implemented by Consumers) are in compliance with the legislation and enforceable by the MPSC. The legislation provides that the rights of parties to existing contracts between utilities (like Consumers) and QFs (like MCV), including the rights to have the PPA charges recovered from customers of the utilities, are not abrogated or diminished, and permits utilities to securitize certain stranded costs, including PPA charges.

In 1999, the U.S. District Court granted summary judgment to MCV declaring that the Restructuring Orders are preempted by federal law to the extent they prohibit Consumers from recovering from its customers any charge for avoided costs (or stranded costs) to be paid to MCV under PURPA pursuant to the PPA. In 2001, the United States Court of Appeals (Appellate Court) vacated the U.S. District Court s 1999 summary judgment and ordered the case dismissed based upon a finding that no actual case or controversy existed for adjudication between the parties. The Appellate Court determined that the parties dispute is hypothetical at this time and the QFs (including MCV) claims are premised on speculation about how an order might be interpreted by the MPSC, in the future.

Two significant issues that could affect MCV s future financial performance are the price of natural gas and Consumers ability/obligation to pay PPA charges. Natural gas prices have historically been volatile and presently there is no consensus among forecasters on the price or range of future prices of natural gas. Even with the approved Resource Conservation Agreement and Reduced Dispatch Agreement, if gas prices continue at present levels or increase, the economics of operating the Facility may be adversely affected. Consumers ability/obligation to pay PPA charges may be affected by an MPSC order denying Consumers recovery from ratepayers. This issue is likely to be addressed in the timeframe of 2007 or beyond. MCV continues to monitor and participate in these matters as appropriate, and to evaluate potential impacts on both cash flows and recoverability of the carrying value of property, plant and equipment. MCV management cannot, at this time, predict the impact or outcome of these matters.

(2) Significant Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Following is a discussion of MCV s significant accounting policies.

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Principles of Consolidation

The consolidated financial statements included the accounts of MCV and its wholly-owned subsidiaries, PVCO Corp. and MCV GAGP. Previously, all material transactions and balances among entities, which comprise MCV, had been eliminated in the consolidated financial statements. The 2004 dissolution of these wholly-owned subsidiaries had no impact on the financial position and results of operations.

Revenue Recognition

MCV recognizes revenue for the sale of variable energy and fixed energy when delivered. Capacity and other installment revenues are recognized based on plant availability or other contractual arrangements.

Fuel Costs

MCV s fuel costs are those costs associated with securing natural gas, transportation and storage services necessary to generate electricity and steam from the Facility. These costs are recognized in the income statement based upon actual volumes burned to produce the delivered energy. In addition, MCV engages in certain cost mitigation activities to offset the fixed charges MCV incurs for these activities. The gains or losses resulting from these activities have resulted in net gains of approximately $6.7 million, $7.7 million and $3.9 million for the years ended 2004, 2003 and 2002, respectively. These net gains are reflected as a component of fuel costs.

In July 2000, in response to rapidly escalating natural gas prices and since Consumers electric rates were frozen, MCV entered into a series of transactions with Consumers whereby Consumers agreed to reduce MCV s dispatch level and MCV agreed to share with Consumers the savings realized by not having to generate electricity (Dispatch Mitigation). On January 1, 2004, Dispatch Mitigation ceased and Consumers began dispatching MCV pursuant to a 915 MW settlement and a 325 MW settlement availability caps provision (i.e., minimum dispatch of 1100 MW on- and off-peak (Forced Dispatch)). In 2004, MCV and Consumers entered into a Resource Conservation Agreement (RCA) and a Reduced Dispatch Agreement (RDA) which, among other things, provides that Consumers will economically dispatch MCV, if certain conditions are met. Such dispatch is expected to reduce electric production from what is occurring under the Forced Dispatch, as well as decrease gas consumption by MCV. The RCA provides that Consumers has a right of first refusal to purchase, at market prices, the gas conserved under the RCA. The RCA and RDA provide for the sharing of savings realized by not having to generate electricity. The RCA and RDA were approved by an order of the MPSC on January 25, 2005 and MCV and Consumers accepted the terms of the MPSC order making the RCA and RDA effective as of January 27, 2005. This MPSC order is subject to appeal by other parties. MCV management cannot predict the final outcome of any such appeal. While awaiting approval of this order, effective October 23, 2004, MCV and Consumers entered into an interim Dispatch Mitigation program for energy dispatch above 1100 MW up to 1240 MW of Contract Capacity under the PPA. This interim program, which was structured very similarly to the RCA and RDA, was terminated on January 27, 2005 with the effective date of the RCA/ RDA. For the twelve months ended December 31, 2004, 2003 and 2002, MCV estimates that these programs have resulted in net savings of approximately $1.6 million, $13.0 million and $2.5 million, a portion of which is realized in reduced maintenance expenditures in future years.

Accounts Receivable

Accounts receivable and accounts receivable-related parties are recorded at the billed amount and do not bear interest. MCV evaluates the need for an allowance for doubtful accounts using MCV s best estimate of the amount of probable credit losses. At December 31, 2004 and 2003, no allowance was provided since typically all receivables are collected within 30 days of each month end.

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Inventory

MCV s inventory of natural gas is stated at the lower of cost or market, and valued using the last-in, first-out (LIFO) method. Inventory includes the costs of purchased gas, variable transportation and storage. The amount of reserve to reduce inventories from first-in, first-out (FIFO) basis to the LIFO basis at December 31, 2004 and 2003, was $10.3 million and $8.4 million, respectively. Inventory cost, determined on a FIFO basis, approximates current replacement cost.

Materials and Supplies

Materials and supplies are stated at the lower of cost or market using the weighted average cost method. The majority of MCV s materials and supplies are considered replacement parts for MCV s Facility.

Depreciation

Original plant, equipment and pipeline were valued at cost for the constructed assets and at the asset transfer price for purchased and contributed assets, and are depreciated using the straight-line method over an estimated useful life of 35 years, which is the term of the PPA, except for the hot gas path components of the GTGs which are primarily being depreciated over a 25-year life. Plant construction and additions, since commercial operations in 1990, are depreciated using the straight-line method over the remaining life of the plant which currently is 22 years. Major renewals and replacements, which extend the useful life of plant and equipment are capitalized, while maintenance and repairs are expensed when incurred. Major equipment overhauls are capitalized and amortized to the next equipment overhaul. Personal property is depreciated using the straight-line method over an estimated useful life of 5 to 15 years. The cost of assets and related accumulated depreciation are removed from the accounts when sold or retired, and any resulting gain or loss reflected in operating income.

Federal Income Tax

MCV is not subject to Federal or State income taxes. Partnership earnings are taxed directly to each individual partner.

Statement of Cash Flows

All liquid investments purchased with a maturity of three months or less at time of purchase are considered to be current cash equivalents.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents and short-term investments approximate fair value because of the short maturity of these instruments. MCV s short-term investments, which are made up of investment securities held-to-maturity, as of December 31, 2004 and December 31, 2003 have original maturity dates of approximately one year or less. The unique nature of the negotiated financing obligation discussed in Note 6 makes it unnecessary to estimate the fair value of the Owner Participants underlying debt and equity instruments supporting such financing obligation, since SFAS No. 107 Disclosures about Fair Value of Financial Instruments does not require fair value accounting for the lease obligation.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, MCV adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities which was issued in June 1998 and then amended by SFAS No. 137, Accounting for Derivative Instruments and Hedging Activities Deferral of the Effective Date of SFAS No. 133, SFAS No. 138 Accounting for Certain Derivative Instruments and Certain Hedging Activities An

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

amendment of FASB Statement No. 133 and SFAS No. 149 Amendment of Statement 133 on Derivative Instruments and Hedging Activity (collectively referred to as SFAS No. 133). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges in some cases allows a derivative s gains and losses to offset related results on the hedged item in the income statement or permits recognition of the hedge results in other comprehensive income, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Electric Sales Agreements

MCV believes that its electric sales agreements currently do not qualify as derivatives under SFAS No. 133, due to the lack of an active energy market (as defined by SFAS No. 133) in the State of Michigan and the transportation cost to deliver the power under the contracts to the closest active energy market at the Cinergy hub in Ohio and as such does not record the fair value of these contracts on its balance sheet. If an active energy market emerges, MCV intends to apply the normal purchase, normal sales exception under SFAS No. 133 to its electric sales agreements, to the extent such exception is applicable.

Natural Gas Supply Contracts

MCV management believes that its long-term natural gas contracts, which do not contain volume optionality, qualify under SFAS No. 133 for the normal purchases and normal sales exception. Therefore, these contracts are currently not recognized at fair value on the balance sheet.

The FASB issued DIG Issue C-16, which became effective April 1, 2002, regarding natural gas commodity contracts that combine an option component and a forward component. This guidance requires either that the entire contract be accounted for as a derivative or the components of the contract be separated into two discrete contracts. Under the first alternative, the entire contract considered together would not qualify for the normal purchases and sales exception under the revised guidance. Under the second alternative, the newly established forward contract could qualify for the normal purchases and sales exception, while the option contract would be treated as a derivative under SFAS No. 133 with changes in fair value recorded through earnings. At April 1, 2002, MCV had nine long-term gas contracts that contained both an option and forward component. As such, they were no longer accounted for under the normal purchases and sales exception and MCV began mark-to-market accounting of these nine contracts through earnings. As of January 31, 2005, only four contracts of the original nine contracts, which contained an option and forward component remain in effect. In addition, as a result of implementing the RCA/ RDA, effective January 27, 2005, MCV has determined that as of the effective date of the RCA/ RDA, an additional nine long term contracts (for a total of 13) will no longer be accounted for under the normal purchases and sales exception, per SFAS No. 133 and will result in additional mark-to-market activity in 2005 and beyond. MCV expects future earnings volatility on both the remaining long term gas contracts that contain volume optionality as well as the long term gas contracts under the RCA/ RDA that will require mark-to-market recognition on a quarterly basis.

Based on the natural gas prices, at the beginning of April 2002, MCV recorded a $58.1 million gain for the cumulative effect of this accounting change. From April 2002 to December 2004, MCV recorded an additional net mark-to-market loss of $2.3 million for these gas contracts. The cumulative mark-to-market gain through December 31, 2004 of $55.8 million is recorded as a current and non-current derivative asset on the balance sheet, as detailed below. These assets will reverse over the remaining life of these gas contracts, ranging from 2005 to 2007. For the twelve months ended December 31, 2004 and 2003, MCV recorded in Fuel costs losses of $19.2 million and $5.0 million, respectively, for net mark-to-market adjustments

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associated with these contracts. In addition, as of December 31, 2004 and 2003, MCV recorded Derivative assets in Current Assets in the amount of $31.4 million and $56.9 million, respectively, and for the same periods recorded Derivative assets non-current in Other Assets in the amount of $24.3 million and $18.1 million, respectively, representing the mark-to-market value on these long-term natural gas contracts.

Natural Gas Supply Futures and Options

To manage market risks associated with the volatility of natural gas prices, MCV maintains a gas hedging program. MCV enters into natural gas futures contracts, option contracts, and over the counter swap transactions (OTC swaps) in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are being utilized principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize MCV s existing gas supply, storage and transportation arrangements.

These financial instruments are derivatives under SFAS No. 133 and the contracts that are utilized to secure the anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133, since they hedge the price risk associated with the cost of natural gas. MCV also engages in cost mitigation activities to offset the fixed charges MCV incurs in operating the Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for MCV and do not qualify as hedges under SFAS No. 133. Therefore, the resulting mark-to-market gains and losses from cost mitigation activities are flowed through MCV s earnings.

Cash is deposited with the broker in a margin account at the time futures or options contracts are initiated. The change in market value of these contracts requires adjustment of the margin account balances. The margin account balance as of December 31, 2004 and 2003 was recorded as a current asset in Broker margin accounts and prepaid expenses, in the amount of $1.4 million and $4.1 million, respectively.

For the twelve months ended December 31, 2004, MCV has recognized in other comprehensive income, an unrealized $34.5 million increase on the futures contracts and OTC swaps, which are hedges of forecasted purchases for plant use of market priced gas. This resulted in a net $65.8 million gain in other comprehensive income as of December 31, 2004. This balance represents natural gas futures, options and OTC swaps with maturities ranging from January 2005 to December 2009, of which $33.4 million of this gain is expected to be reclassified into earnings within the next twelve months. MCV also has recorded, as of December 31, 2004, a $63.6 million current derivative asset in Derivative assets, representing the mark-to-market gain on natural gas futures for anticipated projected electric and steam sales accounted for as hedges. In addition, for the twelve months ended December 31, 2004, MCV has recorded a net $36.5 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $1.8 million gain in earnings from cost mitigation activities.

For the twelve months ended December 31, 2003, MCV recognized an unrealized $5.0 million increase in other comprehensive income on the futures contracts, which are hedges of forecasted purchases for plant use of market priced gas, which resulted in a $31.3 million gain balance in other comprehensive income as of December 31, 2003. As of December 31, 2003, MCV had recorded a $29.9 million current derivative asset in Derivative assets. For the twelve months ended December 31, 2003, MCV had recorded a net $35.0 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $1.0 million gain in earnings from cost mitigation activities.

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New Accounting Standard

In 2003, the Emerging Issues Task Force (EITF) issued EITF 03-1 The Meaning of Other-Than-Temporary Impairment and It s Application to Certain Investments . EITF 03-1 addresses how to determine the meaning of other-than-temporary impairment of certain debt and equity securities, the measurement of an impairment loss and accounting and disclosure considerations subsequent to the recognition of an other-than-temporary impairment. The various sections of EITF 03-1 became effective at various times during 2004. MCV has adopted this guidance and does not expect the application to materially affect it financial position or results of operations, since MCV s investments approximate fair value due to the short maturity of its permitted investments.

(3) Restricted Investment Securities Held-to-Maturity

Non-current restricted investment securities held-to-maturity have carrying amounts that approximate fair value because of the short maturity of these instruments and consist of the following at December 31 (in thousands):

	2004	2003
Funds restricted for rental payments pursuant to the Overall Lease Transaction	$ 138,150	$ 137,296
Funds restricted for management non-qualified plans	1,260	2,459
Total	$ 139,410	$ 139,755

(4) Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consist of the following at December 31 (in thousands):

	2004	2003
Accounts payable		
Related parties	$ 12,772	$ 7,386
Trade creditors	53,476	34,786
Property and single business taxes	11,833	12,548
Other	4,612	2,648
Total	$ 82,693	$ 57,368

(5) Gas Supplier Funds on Deposit

Pursuant to individual gas contract terms with counterparties, deposit amounts or letters of credit may be required by one party to the other based upon the net amount of exposure. The net amount of exposure will vary with changes in market prices, credit provisions and various other factors. Collateral paid or received will be posted by one party to the other based on the net amount of the exposure. Interest is earned on funds on deposit. As of December 31, 2004, MCV is supplying credit support to two gas suppliers; one in the form of a letter of credit in the amount of $2.4 million; and cash on deposit with the other in the amount of $7.3 million. As of December 31, 2004, MCV is holding $19.6 million of cash on deposit from two of MCV s brokers. In addition as of December 31, 2004, MCV is also holding letters of credit totaling $208.6 million from two gas suppliers, of which $184.0 million is a letter of credit from El Paso Corporation (El Paso), a related party.

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(6) Long-Term Debt

Long-term debt consists of the following at December 31 (in thousands):

	2004	2003
Financing obligation, maturing through 2015, payable in semi-annual installments of principal and interest, collateralized by property, plant and equipment	$ 1,018,645	$ 1,153,221
Less current portion	(76,548)	(134,576)
Total long-term debt	$ 942,097	$ 1,018,645

Financing Obligation

In June 1990, MCV obtained permanent financing for the Facility by entering into sale and leaseback agreements (Overall Lease Transaction) with a lessor group, related to substantially all of MCV s fixed assets. Proceeds of the financing were used to retire borrowings outstanding under existing loan commitments, make a capital distribution to the Partners and retire a portion of notes issued by MCV to MEC Development Corporation (MDC) in connection with the transfer of certain assets by MDC to MCV. In accordance with SFAS No. 98, Accounting For Leases, the sale and leaseback transaction has been accounted for as a financing arrangement.

The financing obligation utilizes the effective interest rate method, which is based on the minimum lease payments required through the end of the basic lease term of 2015 and management s estimate of additional anticipated obligations after the end of the basic lease term. The effective interest rate during the remainder of the basic lease term is approximately 9.4%.

Under the terms of the Overall Lease Transaction, MCV sold undivided interests in all of the fixed assets of the Facility for approximately $2.3 billion, to five separate owner trusts (Owner Trusts) established for the benefit of certain institutional investors (Owner Participants). U.S. Bank National Association (formerly known as State Street Bank and Trust Company) serves as owner trustee (Owner Trustee) under each of the Owner Trusts, and leases undivided interests in the Facility on behalf of the Owner Trusts to MCV for an initial term of 25 years. CMS Midland Holdings Company (CMS Holdings), currently a wholly owned subsidiary of Consumers, acquired a 35% indirect equity interest in the Facility through its purchase of an interest in one of the Owner Trusts.

The Overall Lease Transaction requires MCV to achieve certain rent coverage ratios and other financial tests prior to a distribution to the Partners. Generally, these financial tests become more restrictive with the passage of time. Further, MCV is restricted to making permitted investments and incurring permitted indebtedness as specified in the Overall Lease Transaction. The Overall Lease Transaction also requires filing of certain periodic operating and financial reports, notification to the lessors of events constituting a material adverse change, significant litigation or governmental investigation, and change in status as a qualifying facility under FERC proceedings or court decisions, among others. Notification and approval is required for plant modification, new business activities, and other significant changes, as defined. In addition, MCV has agreed to indemnify various parties to the sale and leaseback transaction against any expenses or environmental claims asserted, or certain federal and state taxes imposed on the Facility, as defined in the Overall Lease Transaction.

Under the terms of the Overall Lease Transaction and refinancing of the tax-exempt bonds, approximately $25.0 million of transaction costs were a liability of MCV and have been recorded as a deferred cost. Financing costs incurred with the issuance of debt are deferred and amortized using the interest method over the remaining portion of the 25-year lease term. Deferred financing costs of approximately $1.2 million, $1.4 million and $1.5 million were amortized in the years 2004, 2003 and 2002, respectively.

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Interest and fees incurred related to long-term debt arrangements during 2004, 2003 and 2002 were $103.4 million, $111.9 million and $118.3 million, respectively.

Interest and fees paid during 2004, 2003 and 2002 were $108.6 million, $115.4 million and $122.1 million, respectively.

Minimum payments due under these long-term debt arrangements over the next five years are (in thousands):

	Principal	Interest	Total
2005	$ 76,548	$ 97,835	$ 174,383
2006	63,459	92,515	155,974
2007	62,916	87,988	150,904
2008	67,753	83,163	150,916
2009	70,335	76,755	147,090
	$ 341,011	$ 438,256	$ 779,267

Revolving Credit Agreement

MCV has also entered into a working capital line (Working Capital Facility), which expires August 27, 2005. Under the terms of the existing agreement, MCV can borrow up to the $50.0 million commitment, in the form of short-term borrowings or letters of credit collateralized by MCV s natural gas inventory and earned receivables. At any given time, borrowings and letters of credit are limited by the amount of the borrowing base, defined as 90% of earned receivables and 50% of natural gas inventory, capped at $15 million. MCV did not utilize the Working Capital Facility during the year 2004, except for letters of credit associated with normal business practices. At December 31, 2004, MCV had $47.6 million available under its Working Capital Facility. As of December 31, 2004, MCV s borrowing base was capped at the maximum amount available of $50.0 million and MCV had outstanding letters of credit in the amount of $2.4 million. MCV believes that amounts available to it under the Working Capital Facility along with available cash reserves will be sufficient to meet any working capital shortfalls that might occur in the near term.

Intercreditor Agreement

MCV has also entered into an Intercreditor Agreement with the Owner Trustee, Working Capital Lender, U.S. Bank National Association as Collateral Agent (Collateral Agent) and the Senior and Subordinated Indenture Trustees. Under the terms of this agreement, MCV is required to deposit all revenues derived from the operation of the Facility with the Collateral Agent for purposes of paying operating expenses and rent. In addition, these funds are required to pay construction modification costs and to secure future rent payments. As of December 31, 2004, MCV has deposited $138.2 million into the reserve account. The reserve account is to be maintained at not less than $40 million nor more than $137 million (or debt portion of next succeeding basic rent payment, whichever is greater). Excess funds in the reserve account are periodically transferred to MCV. This agreement also contains provisions governing the distribution of revenues and rents due under the Overall Lease Transaction, and establishes the priority of payment among the Owner Trusts, creditors of the Owner Trusts, creditors of MCV and the Partnership.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) Commitments and Other Agreements

MCV has entered into numerous commitments and other agreements related to the Facility. Principal agreements are summarized as follows:

Power Purchase Agreement

MCV and Consumers have executed the PPA for the sale to Consumers of a minimum amount of electricity, subject to the capacity requirements of Dow and any other permissible electricity purchasers. Consumers has the right to terminate and/or withhold payment under the PPA if the Facility fails to achieve certain operating levels or if MCV fails to provide adequate fuel assurances. In the event of early termination of the PPA, MCV would have a maximum liability of approximately $270 million if the PPA were terminated in the 12th through 24th years. The term of this agreement is 35 years from the commercial operation date and year-to-year thereafter.

Steam and Electric Power Agreement

MCV and Dow executed the SEPA for the sale to Dow of certain minimum amounts of steam and electricity for Dow s facilities.

If the SEPA is terminated, and Consumers does not fulfill MCV s commitments as provided in the Backup Steam and Electric Power Agreement, MCV will be required to pay Dow a termination fee, calculated at that time, ranging from a minimum of $60 million to a maximum of $85 million. This agreement provides for the sale to Dow of steam and electricity produced by the Facility for terms of 25 years and 15 years, respectively, commencing on the commercial operation date and year-to-year thereafter.

Steam Purchase Agreement

MCV and DCC executed the SPA for the sale to DCC of certain minimum amounts of steam for use at the DCC Midland site. Steam sales under the SPA commenced in July 1996. Termination of this agreement, prior to expiration, requires the terminating party to pay to the other party a percentage of future revenues, which would have been realized had the initial term of 15 years been fulfilled. The percentage of future revenues payable is 50% if termination occurs prior to the fifth anniversary of the commercial operation date and 33^{1}/3% if termination occurs after the fifth anniversary of this agreement. The term of this agreement is 15 years from the commercial operation date of steam deliveries under the contract and year-to-year thereafter.

Gas Supply Agreements

MCV has entered into gas purchase agreements with various producers for the supply of natural gas. The current contracted volume totals 238,531 MMBtu per day annual average for 2005. As of January 1, 2005, gas contracts with U.S. suppliers provide for the purchase of 173,336 MMBtu per day while gas contracts with Canadian suppliers provide for the purchase of 65,195 MMBtu per day. Some of these contracts require MCV to pay for a minimum amount of natural gas per year, whether or not taken. The estimated minimum commitments under these contracts based on current long term prices for gas for the years 2005 through 2009 are $384.6 million, $402.1 million, $436.7 million, $358.8 million and $324.0 million, respectively. A portion of these payments may be utilized in future years to offset the cost of quantities of natural gas taken above the minimum amounts.

Gas Transportation Agreements

MCV has entered into firm natural gas transportation agreements with various pipeline companies. These agreements require MCV to pay certain reservation charges in order to reserve the transportation capacity.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

MCV incurred reservation charges in 2004, 2003 and 2002, of $35.5 million, $34.8 million and $35.1 million, respectively. The estimated minimum reservation charges required under these agreements for each of the years 2005 through 2009 are $34.3 million, $30.0 million, $21.6 million, $21.6 million and $21.6 million, respectively. These projections are based on current commitments.

Gas Turbine Service Agreements

Under a Service Agreement, as amended, with Alstom, which commenced on January 1, 1990 and was set to expire upon the earlier of the completion of the sixth series of major GTG inspections or December 31, 2009, Alstom sold MCV an initial inventory of spare parts for the GTGs and provided qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV s request. The Service Agreement was terminated for cause by MCV in February 2004. Alstom disputed MCV s right to terminate for cause. The parties settled the dispute and the agreement terminated in February 2004.MCV has a maintenance service and parts agreement with General Electric International, Inc. (GEII), which commenced July 1, 2004 (GEII Agreement). GEII will provide maintenance services and hot gas path parts for MCV s twelve GTGs, including providing an initial inventory of spare parts for the GTGs and providing qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV s request. Under terms and conditions similar to the MCV/ Alstom Service Agreement, as described above the GEII Agreement will cover four rounds of major GTG inspections, which are expected to be completed by the year 2015, at a savings to MCV as compared to the Service Agreement with Alstom. MCV is to make monthly payments over the life of the contract totaling approximately $207 million (subject to escalations based on defined indices. The GEII Agreement can be terminated by either party for cause or convenience. Should termination for convenience occur, a buy out amount will be paid by the terminating party with payments ranging from approximately $19.0 million to $.9 million, based upon the number of operating hours utilized since commencement of the GEII Agreement.

Steam Turbine Service Agreement

MCV entered into a nine year Steam Turbine Maintenance Agreement with General Electric Company effective January 1, 1995, which is designed to improve unit reliability, increase availability and minimize unanticipated maintenance costs. In addition, this contract includes performance incentives and penalties, which are based on the length of each scheduled outage and the number of forced outages during a calendar year. Effective February 1, 2004, MCV and GE amended this contract to extend its term through August 31, 2007. MCV will continue making monthly payments over the life of the contract, which will total $22.3 million (subject to escalation based on defined indices). The parties have certain termination rights without incurring penalties or damages for such termination. Upon termination, MCV is only liable for payment of services rendered or parts provided prior to termination.

Site Lease

In December 1987, MCV leased the land on which the Facility is located from Consumers (Site Lease). MCV and Consumers amended and restated the Site Lease to reflect the creation of five separate undivided interests in the Site Lease as of June 1, 1990. Pursuant to the Overall Lease Transaction, MCV assigned these undivided interests in the Site Lease to the Owner Trustees, which in turn subleased the undivided interests back to MCV under five separate site subleases.

The Site Lease is for a term which commenced on December 29, 1987, and ends on December 31, 2035, including two renewal options of five years each. The rental under the Site Lease is $.6 million per annum, including the two five-year renewal terms.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(8) Contingencies

Property Taxes

In 1997, MCV filed a property tax appeal against the City of Midland at the Michigan Tax Tribunal contesting MCV s 1997 property taxes. Subsequently, MCV filed appeals contesting its property taxes for tax years 1998 through 2004 at the Michigan Tax Tribunal. A trial was held for tax years 1997-2000. The appeals for tax years 2001-2004 are being held in abeyance. On January 23, 2004, the Michigan Tax Tribunal issued its decision in MCV s tax appeal against the City of Midland for tax years 1997 through 2000 and has issued several orders correcting errors in the initial decision (together the MTT Decision). MCV management has estimated that the MTT Decision will result in a refund to MCV for the tax years 1997 through 2000 of at least approximately $35.3 million in taxes plus $9.6 million of interest as of December 31, 2004. The MTT Decision has been appealed to the Michigan Appellate Court by the City of Midland. MCV has filed a cross-appeal at the Michigan Appellate Court. MCV management cannot predict the outcome of these legal proceedings. MCV has not recognized any of the above stated refunds (net of approximately $16.1 million of deferred expenses) in earnings at this time.

NOx Allowances

The United States Environmental Protection Agency (US EPA) has approved the State of Michigan s State Implementation Plan (SIP), which includes an interstate NOx budget and allowance trading program administered by the US EPA beginning in 2004. Each NOx allowance permits a source to emit one ton of NOx during the seasonal control period, which for 2004 was from May 31 through September 30. NOx allowances may be bought or sold and unused allowances may be banked for future use, with certain limitations. MCV estimates that it will have excess NOx allowances to sell under this program. Consumers has given notice to MCV that it believes the ownership of the NOx allowances under this program belong, at least in part, to Consumers. MCV has initiated the dispute resolution process pursuant to the PPA to resolve this issue and the parties have entered into a standstill agreement deferring the resolution of this dispute. However, either party may terminate the standstill agreement at any time and reinstate the PPA s dispute resolution provisions. MCV management cannot predict the outcome of this issue. As of December 31, 2004, MCV has sold 1,200 tons of 2004 allowances for $2.7 million, which is recorded in Accounts payable and accrued liabilities , pending resolution of ownership of these credits.

Environmental Issues

On July 12, 2004 the Michigan Department of Environmental Quality (DEQ), Air Quality Division, issued MCV a Letter of Violation asserting that MCV violated its Air Use Permit to Install No. 209-02 (PTI) by exceeding the carbon monoxide emission limit on the Unit 14 GTG duct burner and failing to maintain certain records in the required format. On July 13, 2004 the DEQ, Water Division, issued MCV a Notice Letter asserting MCV violated its National Pollutant Discharge Elimination System Permit by discharging heated process waste water into the storm water system, failure to document inspections, and other minor infractions (alleged NPDES violations).

MCV has declared all duct burners as unavailable for operational use (which reduces the generation capability of the Facility by approximately 100 MW) and is assessing the duct burner issue and has begun other corrective action to address the DEQ s assertions. MCV disagrees with certain of the DEQ s assertions. MCV filed responses to these DEQ letters in July and August 2004. On December 13, 2004, the DEQ informed MCV that it was pursuing an escalated enforcement action against MCV regarding the alleged violations of MCV s PTI. The DEQ also stated that the alleged violations are deemed federally significant and, as such, placed MCV on the United States Environmental Protection Agency s High Priority Violators List (HPVL). The DEQ and MCV are pursuing voluntary settlement of this matter, which will satisfy state and federal requirements and remove MCV from the HPVL. Any such settlement is likely to involve a fine,

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

but the DEQ has not, at this time, stated what, if any, fine they will seek to impose. At this time, MCV management cannot predict the financial impact or outcome of these issues, however, MCV believes it has resolved all issues associated with the alleged NPDES violations and does not expect any further MDEQ actions on this NPDES matter.

(9) Voluntary Severance Program

In July 2004, MCV announced a Voluntary Severance Program (VSP) for all employees (union and non-union employees), subject to certain eligibility requirements. The VSP entitled participating employees, upon termination, to a lump sum payment, based upon number of years of service up to a maximum of 52 weeks of wages. Nineteen employees elected to participate in the VSP and MCV has recorded $1.7 million of severance costs in Operating Expenses related to the nineteen employees.

(10) Retirement Benefits

Postretirement Health Care Plans

In 1992, MCV established defined cost postretirement health care plans (Plans) that cover all full-time employees, excluding key management. The Plans provide health care credits, which can be utilized to purchase medical plan coverage and pay qualified health care expenses. Participants become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The Plans granted retroactive benefits for all employees hired prior to January 1, 1992. This prior service cost has been amortized to expense over a five-year period. MCV annually funds the current year service and interest cost as well as amortization of prior service cost to both qualified and non-qualified trusts. The MCV accounts for retiree medical benefits in accordance with SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions. This standard required the full accrual of such costs during the years that the employee renders service to the MCV until the date of full eligibility. The accumulated benefit obligation of the Plans were $4.9 million at December 31, 2004 and $3.3 million at December 31, 2003. The measurement date of these Plans was December 31, 2004.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law in December 2003. The Act expanded Medicare to include, for the first time, coverage for prescription drugs. At December 31, 2003, based upon FASB staff position, SFAS No. 106-1, Employers Accounting for Postretirement Benefits Other Than Pensions, MCV had elected to defer financial recognition of this legislation until issuance of final accounting guidance. The final SFAS No. 106-2 was issued in second quarter 2004 and supersedes SFAS No. 106-1, which MCV adopted during this same period. The adoption of this standard had no impact to MCV s financial position because MCV does not consider its Plans to be actuarially equivalent. The Plans benefits provided to eligible participants are not annual or on-going in nature, but are a readily exhaustible, lump-sum amount available for use at the discretion of the participant.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reconciles the change in the Plans benefit obligation and change in Plan assets as reflected on the balance sheet as of December 31 (in thousands):

	2004	2003
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 3,276.0	$ 2,741.9
Service cost	232.1	212.5
Interest cost	174.8	178.2
Actuarial gain (loss)	1,298.0	147.4
Benefits paid during year	(8.3)	(4.0)
Benefit obligation at end of year	4,972.6	3,276.0
Change in Plan assets:		
Fair value of Plan assets at beginning of year	2,826.8	2,045.8
Actual return on Plan assets	292.7	527.5
Employer contribution	206.5	257.5
Benefits paid during year	(8.3)	(4.0)
Fair value of Plan assets at end of year	3,317.7	2,826.8
Unfunded (funded) status	1,654.9	449.2
Unrecognized prior service cost	(155.9)	(170.3)
Unrecognized net gain (loss)	(1,499.0)	(278.9)
Accrued benefit cost	$	$

Net periodic postretirement health care cost for years ending December 31, included the following components (in thousands):

	2004	2003	2002
Components of net periodic benefit cost:			
Service cost	$ 232.1	$ 212.5	$ 197.3
Interest cost	174.8	178.2	188.7
Expected return on Plan assets	(216.1)	(163.7)	(167.0)
Amortization of unrecognized net (gain) or loss	15.7	30.5	14.3
Net periodic benefit cost	$ 206.5	$ 257.5	$ 233.3

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	1-Percentage-	1-Percentage

	Point Increase	Point Decrease
Effect on total of service and interest cost components	$ 51.6	$ 44.7
Effect on postretirement benefit obligation	$ 514.8	$ 447.1

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Assumptions used in accounting for the Post-Retirement Health Care Plan were as follows:

	2004	2003	2002
Discount rate	5.75%	6.00%	6.75%
Long-term rate of return on Plan assets	8.00%	8.00%	8.00%
Inflation benefit amount			
1998 through 2004	0.00%	0.00%	0.00%
2005 and later years	5.00%	4.00%	4.00%

The long-term rate of return on Plan assets is established based on MCV s expectations of asset returns for the investment mix in its Plan (with some reliance on historical asset returns for the Plans). The expected returns for various asset categories are blended to derive one long-term assumption.

Plan Assets. Citizens Bank has been appointed as trustee (Trustee) of the Plan. The Trustee serves as investment consultant, with the responsibility of providing financial information and general guidance to the MCV Benefits Committee. The Trustee shall invest the assets of the Plan in the separate investment options in accordance with instructions communicated to the Trustee from time to time by the MCV Benefit Committee. The MCV Benefits Committee has the fiduciary and investment selection responsibility for the Plan. The MCV Benefits Committee consists of MCV Officers (excluding the President and Chief Executive Officer).

The MCV has a target allocation of 80% equities and 20% debt instruments. These investments emphasis total growth return, with a moderate risk level. The MCV Benefits Committee reviews the performance of the Plan investments quarterly, based on a long-term investment horizon and applicable benchmarks, with rebalancing of the investment portfolio, at the discretion of the MCV Benefits Committee.

MCV s Plan s weighted-average asset allocations, by asset category are as follows as of December 31:

	2004	2003
Asset Category:		
Cash and cash equivalents	1%	11%
Fixed income	19%	17%
Equity securities	80%	72%
Total	100%	100%

Contributions. MCV expects to contribute approximately $.4 million to the Plan in 2005.

Retirement and Savings Plans

MCV sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, MCV makes contributions to the plan of either five or ten percent of an employee s eligible annual compensation dependent upon the employee s age. MCV also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee s savings up to a maximum level. In 2004, 2003 and 2002, MCV contributed $1.4 million, $1.3 million and $1.2 million, respectively under these plans.

Supplemental Retirement Benefits

MCV provides supplemental retirement, postretirement health care and excess benefit plans for key management. These plans are not qualified plans under the Internal Revenue Code; therefore, earnings of the trusts maintained by MCV to fund these plans are taxable to the Partners and trust assets are included in the assets of MCV.

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) Partners Equity and Related Party Transactions

The following table summarizes the nature and amount of each of MCV s Partner s equity interest, interest in profits and losses of MCV at December 31, 2004, and the nature and amount of related party transactions or agreements that existed with the Partners or affiliates as of December 31, 2004, 2003 and 2002, and for each of the twelve month periods ended December 31 (in thousands).

Beneficial Owner, Equity Partner, Type of Partner and Nature of Related Party	Equity Interest	Equity Interest	Related Party Transactions and Agreements	2004	2003	2002
CMS Energy Company						
CMS Midland, Inc.	$ 396,888	49.0%	Power purchase agreements	$ 601,535	$ 513,774	$ 557,149
General Partner; wholly-owned subsidiary of Consumers Energy Company			Purchases under gas transportation agreements	9,349	14,294	23,552
			Purchases under spot gas agreements		663	3,631
			Purchases under gas supply agreements		2,330	11,306
			Gas storage agreement	2,563	2,563	2,563
			Land lease/easement agreements	600	600	600
			Accounts receivable	50,364	40,373	44,289
			Accounts payable	1,031	1,025	3,502
			Sales under spot gas agreements		3,260	1,084
El Paso Corporation	$ 141,397	18.1%				
Source Midland Limited Partnership (SMLP)			Purchase under gas transportation agreements	12,334	13,023	12,463
General Partner; owned by subsidiaries of El Paso Corporation			Purchases under spot gas agreement		610	15,655
			Purchases under gas supply agreement	70,000	54,308	47,136
			Gas agency agreement	264	238	365
			Deferred reservation charges under gas purchase agreement	3,152	4,728	
			Accounts receivable			523
			Accounts payable	10,997	5,751	7,706
			Sales under spot gas agreements		3,474	14,007
El Paso Midland, Inc. (El Paso Midland)	84,838	10.9	See related party activity listed under SMLP.			
General Partner; wholly-owned subsidiary of El Paso						

Corporation						
MEI Limited Partnership (MEI)			See related party activity listed under			
A General and Limited Partner; 50% interest owned by El Paso Midland, Inc. and 50% interest owned by SMLP			SMLP.			
General Partnership Interest	70,701	9.1				
Limited Partnership Interest	7,068	.9				
Micogen Limited Partnership (MLP)	35,348	4.5	See related party activity listed under			
Limited Partner, owned subsidiaries of El Paso Corporation			SMLP.			
Total El Paso Corporation	$ 339,352	43.5%				
The Dow Chemical Company						
The Dow Chemical Company	$ 73,735	7.5%	Steam and electric power agreement	39,055	36,207	29,385
Limited Partner			Steam purchase agreement Dow Corning Corp (affiliate)	4,289	4,017	3,746
			Purchases under demineralized water supply agreement	8,142	6,396	6,605
			Accounts receivable	4,003	3,431	3,635
			Accounts payable	744	610	1,016
			Standby and backup fees	766	731	734
			Sales of gas under tolling agreement			6,442
Alanna Corporation						
Alanna Corporation	$ 1[(1)]	.00001%	Note receivable	1	1	1
Limited Partner; wholly-owned subsidiary of Alanna Holdings Corporation						

Footnotes to Partners Equity and Related Party Transactions

(1) Alanna s capital stock is pledged to secure MCV s obligation under the lease and other overall lease transaction documents.

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EL PASO CORPORATION
UNAUDITED PRO FORMA CONDENSED FINANCIAL STATEMENTS

Unaudited Pro Forma Financial Statements

On January 14, 2005, we sold our remaining interests in Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, L.P., and Enterprise Products Partners L.P. (Enterprise) to affiliates of EPCO, Inc. for approximately $425 million. The transaction included the sale of our 9.9 percent membership interest in the general partner of Enterprise and approximately 13.5 million common units in Enterprise. Previously, on September 30, 2004, we completed the sale of a portion of our ownership interests in GulfTerra Energy Partners, L.P. (GulfTerra) and nine processing plants in South Texas to affiliates of Enterprise. The sales were completed in connection with the closing of the merger between GulfTerra and Enterprise.

In April 2005, our Board of Directors approved the planned sale of our Asian power asset portfolio. As part of this planned sale, we entered into separate agreements to sell our Korean, Chinese and other Asian power plants. Our other Asian power plants consist of two consolidated power plants and six unconsolidated interests that have been accounted for under the equity method. In August 2005 we announced the sale of our south Louisiana gathering and processing assets, which were reported as discontinued operations for the quarter and six months ended June 30, 2005. There can be no assurance that the sale of these assets will occur as anticipated. The sale of our Korean assets and planned sale of our Chinese and south Louisiana assets were not significant for purposes of preparing these unaudited pro forma financial statements.

The unaudited pro forma financial statements that follow are based on our historical consolidated financial statements adjusted for the effects of the sales of our interests in Enterprise and GulfTerra and the nine processing plants, and for the anticipated sale of our interests in the other Asian power assets. The unaudited pro forma balance sheet as of June 30, 2005, assumes that the anticipated disposition of the other Asian power assets occurred on the balance sheet date. The unaudited pro forma statements of income for the six months ended June 30, 2005, and for the year ended December 31, 2004, assume that the disposition of our interest in Enterprise and GulfTerra and the nine processing plants, and the anticipated sale of our other Asian power assets occurred on January 1, 2004. The unaudited pro forma financial statements should be read in conjunction with the historical consolidated financial statements for the six months ended June 30, 2005, and for the year ended December 31, 2004, included on pages F-1 through F-118 of this prospectus, and should not be construed to be indicative of future results or results that actually would have occurred had the transactions occurred on the dates presented. Finally, these pro forma financial statements were prepared in accordance with Article 11 of Regulation S-X. Accordingly, we have not assumed any cost savings or synergies that might occur related to these transactions.

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EL PASO CORPORATION
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
As of June 30, 2005
(In millions)

	El Paso Historical	Other Asia Power Assets Pro Forma Adjustments	Pro Forma
ASSETS			
Current assets			
Cash and cash equivalents	$ 1,540	$ 180(a) (10)(a)	$ 1,710
Accounts and notes receivable, net	1,216	(8)(a)	1,208
Other	2,050	(6)(a)	2,044
Total current assets	4,806	156	4,962
Property, plant and equipment, net	18,687	(6)(a)	18,681
Other assets			
Investments in unconsolidated affiliates	2,275	(100)(a)	2,175
Other	3,908	(45)(a)	3,863
Total assets	$ 29,676	$ 5	$ 29,681
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities			
Accounts payable	$ 1,199	$ (8)(a)	$ 1,191
Short-term financing obligations, including current maturities	1,099		1,099
Other	2,361	(6)(a)	2,355
Total current liabilities	4,659	(14)	4,645
Long-term debt	16,379		16,379
Other liabilities			
Deferred income taxes	1,528	(5)(c)	1,523
Other	3,251		3,251
Commitments and contingencies			
Securities of subsidiaries	59	(3)(a)	56
Stockholders equity			
Preferred stock	750		750
Common stock	1,959		1,959
Additional paid-in-capital	4,431		4,431
Accumulated deficit	(2,941)	18(a) 5(c)	(2,918)
Other	(399)	4(a)	(395)
Total stockholders equity	3,800	27	3,827

Total liabilities and stockholders equity	$ 29,676	$ 5	$ 29,681

See accompanying notes

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EL PASO CORPORATION
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME
For The Six Months Ended June 30, 2005
(In millions, except per common share amounts)

	El Paso Historical	GulfTerra/ Enterprise Pro Forma Adjustments	Other Asia Power Assets Pro Forma Adjustments	Pro Forma
Operating revenues	$ 2,366	$	$ (28)[b]	$ 2,338
Operating expenses				
Cost of products and services	159			159
Operation and maintenance	880		(27)[b]	853
Depreciation, depletion and amortization	574		(3)[b]	571
Loss on long-lived assets	381		(37)[b]	344
Taxes, other than income taxes	136			136
	2,130		(67)	2,063
Operating income	236		39	275
Earnings from unconsolidated affiliates	171	(183)[e]	55[b]	43
Other income, net	104		(1)[b]	103
Interest and debt expense	(690)			(690)
Distributions on preferred interests of consolidated subsidiaries	(9)			(9)
Income (loss) before income taxes	(188)	(183)	93	(278)
Income taxes	(57)	(64)[f]	69[c]	(52)
Income (loss) from continuing operations	$ (131)	$ (119)	$ 24	$ (226)
Basic and diluted income per common share from continuing operations	$ (0.22) [d]			$ (0.37) [d]
Basic and diluted average common shares outstanding	640			640

See accompanying notes.

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EL PASO CORPORATION
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME
For The Twelve Months Ended December 31, 2004
(In millions)

	El Paso Historical	GulfTerra/ Enterprise Pro Forma Adjustments	Other Asia Power Assets Pro Forma Adjustments	Pro Forma
Operating revenues	$ 5,874	$ (722) [e]	$ (52)[b]	$ 5,100
Operating expenses				
Cost of products and services	1,363	(528)[e]		835
Operation and maintenance	1,872	(12)[e]	(48)[b]	1,812
Depreciation, depletion and amortization	1,088	(8)[e]	(7)[b]	1,073
Loss on long-lived assets	1,108	(491)[e]	(30)[b]	587
Taxes, other than income taxes	253	(2)[e]		251
	5,684	(1,041)	(85)	4,558
Operating income	190	319	33	542
Earnings from unconsolidated affiliates	546	(613)[e]	118 [b]	51
Other income, net	94		(2)[b]	92
Interest and debt expense	(1,607)		1 [b]	(1,606)
Distributions on preferred interests of consolidated subsidiaries	(25)			(25)
Income (loss) before income taxes	(802)	(294)	150	(946)
Income taxes	31	(242)[f]	(8)[c]	(219)
Income (loss) from continuing operations	$ (833)	$ (52)	$ 158	$ (727)
Basic and diluted loss per common share from continuing operations	$ (1.30)			$ (1.14)
Basic and diluted average common shares outstanding	639			639

See accompanying notes

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EL PASO CORPORATION
NOTES TO THE UNAUDITED PRO FORMA CONDENSED
CONSOLIDATED STATEMENT OF INCOME

El Paso Historical

These amounts represent our condensed historical consolidated balance sheet and income statement information. Amounts as of and for the six months ended June 30, 2005 were derived from our Quarterly Report on Form 10-Q, for the six months ended June 30, 2005. Amounts for the year ended December 31, 2004 were derived from our 2004 Annual Report on Form 10-K, as amended.

Pro Forma Adjustments

Other Asian Power Assets

These amounts represent the historical results and balances related to our unconsolidated interests in our other Asian power assets including our interests in the Habibullah, Saba, Khulna, NEPC (Haripur), Fauji and Sengkang power plants, which have been accounted for using the equity method and our consolidated interests in the CEBU and East Asia Utility Power plants, as of and for the periods presented. The pro forma adjusting entries reflect the anticipated sale of these interests.

GulfTerra/Enterprise

These amounts represent the historical results related to our interests in Enterprise and GulfTerra which were accounted for as equity investments and the nine processing plants sold to affiliates of EPCO, Inc. for the period presented. The pro forma adjusting entries reflect the following transactions:

The sale of all of our interest in the general partner of Enterprise and GulfTerra;

The elimination of all effects of our common units of GulfTerra and Enterprise and Series C units of GulfTerra; and

The elimination of all non-affiliated effects of the nine processing plants sold.

Pro Forma Adjusting Entries

Other Asian Power Assets

(a) To reflect the pro forma effects of the anticipated sale of our interests in the other Asian power assets noted above on our condensed consolidated balance sheet. The pro forma effects include the following:

(1) Receipt of anticipated proceeds of $180 million from the sale of these interests based on bids received.

(2) Elimination of the individual assets and liabilities of the consolidated power plants and our interests in the unconsolidated power plants.

(3) Gain on the sale of our remaining interests in the Asian power assets of $18 million.

(b) To reflect the pro forma effects of the sale of the interests in our other Asian power assets noted above on our condensed consolidated income statements. The pro forma effects include adjustments for the historical results of operations for the consolidated power plants and unconsolidated affiliates. These adjustments include impairment charges recorded during the six months ended June 30, 2005 and the year ended December 31, 2004.

(c) To eliminate actual U.S. income taxes for our other Asian assets in 2004 and the first six months of 2005. We expect to receive a portion of the proceeds from the sales of these assets within the U.S. and recorded net deferred tax assets and a corresponding income tax expense/benefit on the book versus tax basis differences in these investments. Amounts also reflect the elimination of local income and withholding taxes.

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(d) Earnings per share computations for 2005 include the effect of $8 million of preferred stock dividends.

GulfTerra/Enterprise

(e) To reflect the pro forma effects of the sale of our Enterprise and GulfTerra interests and nine processing plants on our condensed consolidated income statement. The pro forma effects include the following:

(1) Adjustment for the historical results of operations for our nine processing plants, including impairment charges recorded during 2004 on these assets;

(2) Reduction of earnings from unconsolidated affiliates in 2004 for (i) all of our general partner interests in Enterprise and GulfTerra, (ii) all of our Series C units in GulfTerra and (iii) all of the common units sold in both GulfTerra and Enterprise; and

(3) Elimination of gains and losses on long-lived assets during 2004 on sales of our Enterprise and GulfTerra interests, and during 2005 on the sale of our remaining interest in Enterprise.

(f) To reflect income taxes related to the income statement adjustments. Income taxes were computed using a statutory rate of 35 percent, except for taxes on the 2004 net gain related to the sale of our interests in GulfTerra and our nine processing plants. Taxes on the 2004 net gain were computed separately and resulted in an increase in our tax expense of $139 million due to the non-deductibility of goodwill which was written off as a result of these transactions. The statutory rate of 35 percent differs from our effective tax rate.

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, 2005

13,639,403 Shares
El Paso Corporation
Common Stock

PROSPECTUS

WE HAVE NOT AUTHORIZED ANY DEALER, SALESPERSON OR OTHER PERSON TO GIVE YOU WRITTEN INFORMATION OTHER THAN THIS PROSPECTUS OR TO MAKE REPRESENTATIONS AS TO MATTERS NOT STATED IN THIS PROSPECTUS. YOU MUST NOT RELY ON UNAUTHORIZED INFORMATION. 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. NEITHER THE DELIVERY OF THIS PROSPECTUS NOR ANY SALES MADE HEREUNDER AFTER THE DATE OF THIS PROSPECTUS SHALL CREATE AN IMPLICATION THAT THE INFORMATION CONTAINED HEREIN OR THE AFFAIRS OF EL PASO HAVE NOT CHANGED SINCE THE DATE HEREOF.

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PART II
INFORMATION NOT REQUIRED IN PROSPECTUS

ITEM 13. *OTHER EXPENSES OF ISSUANCE AND DISTRIBUTION*

The following table sets forth the costs and expenses, to be incurred by the registrant in connection with the registration of the common stock. All amounts shown are estimated.

Printing and engraving expenses	$	100,000
Legal fees and expenses		150,000
Accounting fees and expenses		75,000
Miscellaneous		50,000
Total	$	375,000

ITEM 14. *INDEMNIFICATION OF DIRECTORS AND OFFICERS*

Section 145 of the Delaware General Corporation Law provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses (including attorneys fees), judgments, fines, and amounts paid in settlement in connection with specified actions, rules, or proceedings, whether civil, criminal, administrative, or investigative (other than action by or in the right of the corporation a derivative action), if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification only extends to expenses (including attorneys fees) incurred in connection with the defense or settlement of such action, and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation. The statute provides that it is not exclusive of other indemnification that may be granted by a corporation s charter, by-laws, disinterested director vote, stockholder vote, agreement, or otherwise.

Article X of El Paso s By-laws requires indemnification to the full extent permitted under Delaware law as from time to time in effect. Subject to any restrictions imposed by Delaware law, the By-laws of El Paso provide an unconditional right to indemnification for all expense, liability, and loss (including attorneys fees, judgments, fines, ERISA excise taxes, or penalties and amounts paid in settlement) actually and reasonably incurred or suffered by any person in connection with any actual or threatened proceeding (including, to the extent permitted by law, any derivative action) by reason of the fact that such person is or was serving as a director, officer, or employee of El Paso or that, being or having been such a director or officer or an employee of El Paso, such person is or was serving at the request of El Paso as a director, officer, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, including an employee benefit plan. The By-laws of El Paso also provide that El Paso may, by action of its Board of Directors, provide indemnification to its agents with the same scope and effect as the foregoing indemnification of directors and officers.

Section 102(b)(7) of the Delaware General Corporation Law permits a corporation to provide in its certificate of incorporation that a director of the corporation shall not be personally liable to the corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability for (i) any breach of the director s duty of loyalty to the corporation or its stockholders, (ii) acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) payment of unlawful dividends or unlawful stock purchases or redemptions, or (iv) any transaction from which the director derived an improper personal benefit.

Article 10 of El Paso s Restated Certificate of Incorporation, as amended, provides that to the full extent that the Delaware General Corporation Law, as it now exists or may hereafter be amended, permits the limitation or elimination of the liability of directors, a director of El Paso shall not be liable to El Paso or its stockholders for monetary damages for breach of fiduciary duty as a director. Any amendment to or repeal of

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such Article 10 shall not adversely affect any right or protection of a director of El Paso for or with respect to any acts or omissions of such director occurring prior to such amendment or repeal.

El Paso has entered into indemnification agreements with each member of the Board of Directors and certain officers, including each of the executives named in this registration statement. These agreements reiterate the rights to indemnification that are provided to our Board of Directors and certain officers under El Paso s By-laws, clarify procedures related to those rights, and provide that such rights are also available to fiduciaries under certain of El Paso s employee benefit plans. As is the case under the By-laws, the agreements provide for indemnification to the full extent permitted by Delaware law, including the right to be paid the reasonable expenses (including attorneys fees) incurred in defending a proceeding related to service as a director, officer or fiduciary in advance of that proceedings final disposition. El Paso may maintain insurance, enter into contracts, create a trust fund or use other means available to provide for indemnity payments and advances. In the event of a change in control of El Paso (as defined in the indemnification agreements), El Paso is obligated to pay the costs of independent legal counsel who will provide advice concerning the rights of each director and officer to indemnity payments and advances.

El Paso maintains directors and officers liability insurance which provides for payment, on behalf of the directors and officers of El Paso and its subsidiaries, of certain losses of such persons (other than matters uninsurable under law) arising from claims, including claims arising under the Securities Act, for acts or omissions by such persons while acting as directors or officers of El Paso and/or its subsidiaries, as the case may be.

ITEM 15. ***RECENT SALES OF UNREGISTERED SECURITIES***

On April 15, 2005, we issued 750,000 shares of 4.99% Convertible Perpetual Preferred Stock in a private placement under Rule 4(2) of the Securities Act of 1933, as amended. The initial purchasers in the transaction were Banc of America Securities LLC and Deutsche Bank Securities Inc. The preferred stock was offered and sold by the initial purchasers only to qualified institutional investors in accordance with Rule 144A under the Securities Act. The gross proceeds to El Paso were approximately $750 million, and the net proceeds to El Paso (after deducting the initial purchasers discounts and commissions and El Paso s estimated expenses) were approximately $722 million.

ITEM 16. ***EXHIBITS***

Each exhibit identified below is filed as part of this registration statement. Exhibits not incorporated by reference to a prior filing or previously filed are designated by an * ; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this registration statement pursuant to Item 601(b)(10) of Regulation S-K.

Exhibit No.	Exhibit
2.A	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (including the form of Assumption Agreement to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.1 to our Form 8-K filed December 15, 2003)

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Exhibit No.	Exhibit
2.B	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the form of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.2 to our Form 8-K filed December 15, 2003); Amendment No. 1 to Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company, dated as of April 19, 2004 (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (Exhibit 2.1 to our Form 8-K filed April 21, 2004); Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003 (Exhibit 2.3 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (Exhibit 2.4 to our Form 8-K filed December 15, 2003)
2.B.1	Purchase and Sale Agreement, dated as of January 14, 2005, by and among Enterprise GP Holdings, L.P., Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso Corporation and GulfTerra GP Holding Company (Exhibit 2.B.1 to our 2004 Form 10-K)
3.A	Amended and Restated Certificate of Incorporation effective as of May 26, 2005 (Exhibit 3.A to our Current Report on Form 8-K filed May 27, 2005)
3.B	By-Laws effective as of July 31, 2003 (Exhibit 3.B to our 2003 Second Quarter Form 10-Q)
4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4.A to our 2004 Form 10-K)
4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (included in Exhibit 3.A to our Current Report on Form 8-K filed May 27, 2005)
4.C	Registration Rights Agreement, dated April 15, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 4.A to our Current Report on Form 8-K filed April 15, 2005)
5.A	Opinion of Andrews Kurth LLP as to the legality of the common stock (Exhibit 5.A to our post-effective amendment no. 1 to Form S-3 on Form S-1 (Registration no. 333-82412) filed May 6, 2005)
10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed

	November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004); Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004)
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004)

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Exhibit No.	Exhibit
10.C	$3,000,000,00 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.1 to our Form 8-K filed April 18, 2003); First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 17, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lender and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 Form 10-K); Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Form 10-K); Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 99.B to our Form 8-K filed August 10, 2004)
10.D	$1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.2 to our Form 8-K filed April 18, 2003)
10.E	Security and Intercreditor Agreement dated as of April 16, 2003 Among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to our Form 8-K filed April 18, 2003)
+10.F	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our 2003 Form 10-K)
+10.G	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.G to our 2004 Form 10-K); Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2004 Form 10-K); Amendment No. 2 effective as of February 7, 2001 to the Stock Option

	Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q)
+10.H	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8, Registration No. 333-64240, filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.H.1 to our 2003 Form 10-K)
+10.I	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I to our 2004 Form 10-K); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.1 to our 2004 Form 10-K); Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.2 to our 2004 Form 10-K)

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Exhibit No.	Exhibit
+10.J	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8, Registration No. 333-78979, filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.I.1 to our 2003 Second Quarter Form 10-Q)
+10.K	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8, Registration No. 333-64236, filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.K.1 to our 2003 Form 10-K)
+10.L	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.K to our 2001 Form 10-K); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.K.1 to our 2002 Form 10-K); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q); Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.L.1 to our 2004 Form 10-K)
+10.M	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.L.1 to our 2002 Form 10-K)
+10.N	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.N to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2003 Third Quarter Form 10-Q)
+10.O	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K)
+10.P	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our 2003 Form 10-K)
+10.Q	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8, Registration No. 333-94717, filed January 14, 2000); Amendment No. 1

	effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.P.1 to our 2002 Form 10-K)
+10.R	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.R to our 2004 Form 10-K)
+10.S	Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.S to our 2004 Form 10-K); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q)

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Exhibit No.	Exhibit
+10.T	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.A to our Form S-8, Registration No. 333-52100, filed December 18, 2000); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.A to our Form S-8, Registration No. 333-52100, filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8, Registration No. 333-82506, filed February 11, 2002); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.T.1 to our 2002 Form 10-K)
+10.U	El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q); Amendment No. 1 effective as of June 6, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.AA.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.V.1 to our 2003 Form 10-K)
+10.V	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Amendment No. 2 to Supplement No. 1 effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 3 to Supplement No. 1 effective as of September 2, 2003 (Exhibit 10.Z.1 to our 2003 Third Quarter Form 10-Q); Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003 (Exhibit 10.W.1 to our 2003 Form 10-K); Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004 (Exhibit 10.W.2 to our 2003 Form 10-K)
+10.W	Employment Agreement Amended and Restated effective as of February 1, 2001 between El Paso and William A. Wise (Exhibit 10.O to our 2000 Form 10-K)
+10.X	Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott. (Exhibit 10.VV to our 2003 Third Quarter Form 10-Q)
+10.Y	Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.U to our 2003 Third Quarter Form 10-Q)
+10.Y.1	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K)
+10.Z	Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart (Exhibit 10.CC to our 2003 Form 10-K)
+10.AA	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.FF to our 2002 Form 10-K)
+10.BB	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective December 17, 2004 (Exhibit 10.WW to our 2003 Third Quarter Form 10-Q)
+10.CC	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2003 Third Quarter Form 10-Q)

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Exhibit No.	Exhibit
10.DD	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to our 2003 Second Quarter Form 10-Q)
10.EE	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our 2003 Form 10-K)
10.FF	Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles (Exhibit 10.II to our 2003 Second Quarter Form 10-Q)
10.GG	Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004, and terminated as described in our Form 8-K filed December 3, 2004)
10.HH	Purchase Agreement dated April 11, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 10.A to our Form 8-K filed April 15, 2005)
+10.II	Agreement and General Release dated May 4, 2005, by and between El Paso Corporation and John W. Somerhalder II (Exhibit 10.A to our Form 8-K filed May 4, 2005)
21	Subsidiaries of El Paso (Exhibit 21 to our 2004 Form 10-K)
*23.A	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Houston)
*23.B	Consent of Independent Registered Public Accounting Firm PricewaterhouseCoopers LLP (Detroit)
*23.C	Consent of Ryder Scott Company, L.P.
23.D	Consent of Andrews Kurth LLP (included in Exhibit 5.A)
24.A	Powers of Attorney (included on signature page to our post-effective amendment no. 1 to Form S-3 on Form S-1 (Registration no. 333-82412) filed May 6, 2005)

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ITEM 17. ***UNDERTAKINGS***

A. The undersigned registrants hereby undertake:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(a) To include any prospectus required by Section 10(a)(3) of the Securities Act;

(b) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement; and

(c) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in this registration statement;

provided, however, that paragraphs A(l)(a) and A(l)(b) above do not apply if the information required to be included in a post-effective amendment by those paragraphs is contained in periodic reports filed with or furnished to the SEC by the registrant pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 that are incorporated by reference in the Registration Statement.

(2) That, for the purpose of determining any liability under the Securities Act, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

B. Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers, and controlling persons of the Registrants pursuant to the provisions described in Item 15 above, or otherwise, the Registrants have been advised that in the opinion of the Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrants of expenses incurred or paid by a director, officer, or controlling person of the Registrants in the successful defense of any action, suit or proceeding) is asserted by such director, officer, or controlling person in connection with the securities being registered, the Registrants will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on this 10th day of August, 2005.

EL PASO CORPORATION
By: /s/ Douglas L. Foshee

Douglas L. Foshee
President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, as amended, this registration statement has been signed by the following persons in the capacities and on the dates as indicated.

Signature	Title	Date
*	Chairman of the Board, Director	August 10, 2005
Ronald L. Kuehn, Jr.		
/s/ Douglas L. Foshee	President, Chief Executive Officer and Director	August 10, 2005
Douglas L. Foshee		
/s/ D. Mark Leland	Executive Vice President and Chief Financial Officer	August 10, 2005
D. Mark Leland		
/s/ Jeffrey I. Beason	Senior Vice President and Controller (Chief Accounting Officer)	August 10, 2005
Jeffrey I. Beason		
*	Director	August 10, 2005
Juan Carlos Braniff		
*	Director	August 10, 2005
James L. Dunlap		
*	Director	August 10, 2005
Robert W. Goldman		
*	Director	August 10, 2005
Anthony W. Hall, Jr.		
*	Director	

Thomas R. Hix		August 10, 2005
*	Director	August 10, 2005
William H. Joyce		
*	Director	August 10, 2005
J. Michael Talbert		

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Signature	Title	Date
Robert F. Vagt	Director	August 10, 2005
* John L. Whitmire	Director	August 10, 2005
* Joe B. Wyatt	Director	August 10, 2005
/s/ Robert W. Baker Robert W. Baker Attorney-in-fact		

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EXHIBIT LIST

Each exhibit identified below is filed as part of this registration statement. Exhibits not incorporated by reference to a prior filing or previously filed are designated by an * ; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this registration statement pursuant to Item 601(b)(10) of Regulation S-K.

Exhibit No.	Exhibit
2.A	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (including the form of Assumption Agreement to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.1 to our Form 8-K filed December 15, 2003)
2.B	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the form of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.2 to our Form 8-K filed December 15, 2003); Amendment No. 1 to Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company, dated as of April 19, 2004 (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (Exhibit 2.1 to our Form 8-K filed April 21, 2004); Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003 (Exhibit 2.3 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (Exhibit 2.4 to our Form 8-K filed December 15, 2003)
2.B.1	Purchase and Sale Agreement, dated as of January 14, 2005, by and among Enterprise GP Holdings, L.P., Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso Corporation and GulfTerra GP Holding Company (Exhibit 2.B.1 to our 2004 Form 10-K)
3.A	Amended and Restated Certificate of Incorporation effective as of May 26, 2005 (Exhibit 3.A to our Current Report on Form 8-K filed May 27, 2005)
3.B	By-Laws effective as of July 31, 2003 (Exhibit 3.B to our 2003 Second Quarter Form 10-Q)
4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4.A to our 2004 Form 10-K)
4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (included in Exhibit 3.A to our Current Report on Form 8-K filed May 27, 2005)

4.C	Registration Rights Agreement, dated April 15, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 4.A to our Current Report on Form 8-K filed April 15, 2005)
5.A	Opinion of Andrews Kurth LLP as to the legality of the common stock (Exhibit 5.A to our post-effective amendment no. 1 to Form S-3 on Form S-1 (Registration no. 333-82412) filed May 6, 2005)

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Exhibit No.	Exhibit
10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004); Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004)
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004)
10.C	$3,000,000,00 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.1 to our Form 8-K filed April 18, 2003); First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 17, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lender and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 Form 10-K); Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Form 10-K); Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 99.B to our Form 8-K filed August 10, 2004)
10.D	$1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee

	Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.2 to our Form 8-K filed April 18, 2003)
10.E	Security and Intercreditor Agreement dated as of April 16, 2003 Among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to our Form 8-K filed April 18, 2003)

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Exhibit No.	Exhibit
+10.F	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our 2003 Form 10-K)
+10.G	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.G to our 2004 Form 10-K); Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2004 Form 10-K); Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q)
+10.H	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8, Registration No. 333-64240, filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.H.1 to our 2003 Form 10-K)
+10.I	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I to our 2004 Form 10-K); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.1 to our 2004 Form 10-K); Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.2 to our 2004 Form 10-K)
+10.J	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8, Registration No. 333-78979, filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.I.1 to our 2003 Second Quarter Form 10-Q)
+10.K	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8, Registration No. 333-64236, filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.K.1 to our 2003 Form 10-K)
+10.L	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.K to our 2001 Form 10-K); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.K.1 to our 2002 Form 10-K); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q); Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.L.1 to our 2004 Form 10-K)
+10.M	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.L.1 to our 2002 Form 10-K)

+10.N	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.N to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2003 Third Quarter Form 10-Q)
+10.O	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K)

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Exhibit No.	Exhibit
+10.P	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 2004 Form 10-K); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our 2003 Form 10-K)
+10.Q	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8, Registration No. 333-94717, filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.P.1 to our 2002 Form 10-K)
+10.R	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.R to our 2004 Form 10-K)
+10.S	Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.S to our 2004 Form 10-K); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q)
+10.T	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.A to our Form S-8, Registration No. 333-52100, filed December 18, 2000); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.A to our Form S-8, Registration No. 333-52100, filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8, Registration No. 333-82506, filed February 11, 2002); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.T.1 to our 2002 Form 10-K)
+10.U	El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q); Amendment No. 1 effective as of June 6, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.AA.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.V.1 to our 2003 Form 10-K)
+10.V	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Amendment No. 2 to Supplement No. 1 effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 3 to Supplement No. 1 effective as of September 2, 2003 (Exhibit 10.Z.1 to our 2003 Third Quarter Form 10-Q); Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003 (Exhibit 10.W.1 to our 2003 Form 10-K); Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004 (Exhibit 10.W.2 to our 2003 Form 10-K)
+10.W	Employment Agreement Amended and Restated effective as of February 1, 2001 between El Paso and William A. Wise (Exhibit 10.O to our 2000 Form 10-K)

+10.X	Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott. (Exhibit 10.VV to our 2004 Third Quarter Form 10-Q)
+10.Y	Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.U to our 2003 Third Quarter Form 10-Q)
+10.Y.1	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K)
+10.Z	Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart (Exhibit 10.CC to our 2003 Form 10-K)
+10.AA	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.FF to our 2002 Form 10-K)

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Exhibit No.	Exhibit
+10.BB	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective December 17, 2004 (Exhibit 10.WW to our 2003 Third Quarter Form 10-Q)
+10.CC	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2003 Third Quarter Form 10-Q)
10.DD	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to our 2003 Second Quarter Form 10-Q)
10.EE	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our 2003 Form 10-K)
10.FF	Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles (Exhibit 10.II to our 2003 Second Quarter Form 10-Q)
10.GG	Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004, and terminated as described in our Form 8-K filed December 3, 2004)
10.HH	Purchase Agreement dated April 11, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 10.A to our Form 8-K filed April 15, 2005)
+10.II	Agreement and General Release dated May 4, 2005, by and between El Paso Corporation and John W. Somerhalder II (Exhibit 10.A to our Form 8-K filed May 4, 2005)
10.JJ	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors (Exhibit 10.A to our Form 8-K filed on May 31, 2005).
10.KK	El Paso Corporation 2005 Omnibus Incentive Compensation Plan (Exhibit 10.B to our Form 8-K filed on May 31, 2005).
10.LL	

	El Paso Corporation Employee Stock Purchase Plan, Amended and Restated Effective as of July 1, 2005. (Exhibit 10.E to our 2005 Second Quarter Form 10-Q)
10.MM	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective August 4, 2005. (Exhibit 10.G to our 2005 Second Quarter Form 10-Q)
21	Subsidiaries of El Paso (Exhibit 21 to our 2004 Form 10-K)
*23.A	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Houston)
*23.B	Consent of Independent Registered Public Accounting Firm PricewaterhouseCoopers LLP (Detroit)
*23.C	Consent of Ryder Scott Company, L.P.
23.D	Consent of Andrews Kurth LLP (included in Exhibit 5.A)
24.A	Powers of Attorney (included on signature page to our post-effective amendment no. 1 to Form S-3 on Form S-1 (Registration no. 333-82412) filed May 6, 2005)