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

Form 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: **(713) 420-2600**
Internet Website: www.elpaso.com

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

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

Common stock, par value $3 per share. Shares outstanding on October 22, 2004: 643,232,071

EL PASO CORPORATION

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

/d	= per day	Mcfe	= thousand cubic feet of natural gas equivalents
Bbl	= barrels	MMBtu	= million British thermal units
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	TBtu	= trillion British thermal units
MBbls	= thousand barrels	MW	= megawatt
Mcf	= thousand cubic feet		

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. Oil includes natural gas liquids unless otherwise specified. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

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

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended March 31,	
	2004	2003 (Restated)
Operating revenues	$1,585	$1,854
Operating expenses		
Cost of products and services	393	605
Operation and maintenance	405	562
Depreciation, depletion and amortization	283	319
Loss on long-lived assets	315	22
Ceiling test charges	28	1
Taxes, other than income taxes	65	78
	1,489	1,587
Operating income	96	267
Earnings (losses) from unconsolidated affiliates	100	(134)
Other income (expense)	37	(5)
Interest and debt expense	(422)	(413)
Distributions on preferred interests of consolidated subsidiaries	(6)	(21)
Loss before income taxes	(195)	(306)
Income tax benefit	(44)	(106)
Loss from continuing operations	(151)	(200)
Discontinued operations, net of income taxes	(55)	(222)
Cumulative effect of accounting changes, net of income taxes	—	(9)
Net loss	$ (206)	$ (431)
Basic and diluted loss per common share		
Loss from continuing operations	$(0.23)	$(0.33)
Discontinued operations, net of income taxes	(0.09)	(0.37)
Cumulative effect of accounting changes, net of income taxes	—	(0.02)
Net loss per common share	$(0.32)	$(0.72)
Basic and diluted average common shares outstanding	638	595
Dividends declared per common share	$ 0.04	$ 0.04

See accompanying notes.

EL PASO CORPORATION

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

	March 31, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,818	$ 1,429
Accounts and notes receivable		
Customers, net of allowance of $265 in 2004 and $273 in 2003	1,486	2,059
Affiliates	139	189
Other	327	247
Inventory	170	184
Assets from price risk management activities	681	706
Assets held for sale and from discontinued operations	1,282	2,505
Restricted cash	713	590
Deferred income taxes	530	592
Other	390	421
Total current assets	7,536	8,922
Property, plant and equipment, at cost		
Pipelines	18,600	18,563
Natural gas and oil properties, at full cost	14,963	15,763
Power facilities	1,588	1,660
Gathering and processing systems	335	334
Other	943	998
	36,429	37,318
Less accumulated depreciation, depletion and amortization	18,273	18,724
Total property, plant and equipment, net	18,156	18,594
Other assets		
Investments in unconsolidated affiliates	3,589	3,551
Assets from price risk management activities	2,345	2,338
Goodwill and other intangible assets, net	1,077	1,088
Other	2,512	2,591
	9,523	9,568
Total assets	$35,215	$37,084

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)
(Unaudited)

	March 31, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,088	$ 1,553
Affiliates	27	26
Other	376	476
Short-term financing obligations, including current maturities	1,472	1,457
Liabilities from price risk management activities	742	734
Western Energy Settlement	671	633
Liabilities related to assets held for sale and discontinued operations	270	894
Accrued interest	408	391
Other	931	910
Total current liabilities	5,985	7,074
Debt		
Long-term financing obligations	19,681	20,275
Other		
Liabilities from price risk management activities	897	781
Deferred income taxes	1,465	1,571
Western Energy Settlement	391	415
Other	2,032	2,047
	4,785	4,814
Commitments and contingencies		
Securities of subsidiaries	434	447
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 648,267,895 shares in 2004 and 639,299,156 shares in 2003	1,944	1,917
Additional paid-in capital	4,597	4,576
Accumulated deficit	(1,991)	(1,785)
Accumulated other comprehensive income	21	11
Treasury stock (at cost); 7,411,357 shares in 2004 and 7,097,326 shares in 2003	(226)	(222)
Unamortized compensation	(15)	(23)
Total stockholders' equity	4,330	4,474
Total liabilities and stockholders' equity	$35,215	$37,084

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Quarter Ended March 31,	
	2004	2003 (Restated)[(1)]
Cash flows from operating activities		
Net loss	$ (206)	$ (431)
Less loss from discontinued operations, net of income taxes	(55)	(222)
Net loss before discontinued operations	(151)	(209)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	283	319
Ceiling test charges	28	1
Loss on long-lived assets	315	22
(Earnings) losses from unconsolidated affiliates, adjusted for cash distributions	(10)	155
Deferred income tax benefit	(55)	(110)
Cumulative effect of accounting changes	—	9
Other non-cash income items	24	198
Asset and liability changes	25	(251)
Cash provided by continuing operations	459	134
Cash provided by (used in) discontinued operations	170	(223)
Net cash provided by (used in) operating activities	629	(89)
Cash flows from investing activities		
Additions to property, plant and equipment	(401)	(674)
Purchases of interests in equity investments	(11)	(1,002)
Net proceeds from the sale of assets and investments	357	1,069
Net change in restricted cash	(124)	(175)
Other	43	(57)
Cash used in continuing operations	(136)	(839)
Cash provided by discontinued operations	753	362
Net cash provided by (used in) investing activities	617	(477)
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(576)	(294)
Net borrowings under short-term debt and credit facilities	—	500
Net proceeds from the issuance of long-term debt and other financing obligations	50	1,822
Dividends paid	(23)	(130)
Payments to redeem preferred interests of consolidated subsidiaries	—	(1,170)
Contributions from discontinued operations	558	139
Issuances of common stock, net	73	—
Other	(16)	29
Cash provided by continuing operations	66	896
Cash used in discontinued operations	(923)	(139)
Net cash provided by (used in) financing activities	(857)	757
Increase in cash and cash equivalents	389	191
Cash and cash equivalents		
Beginning of period	1,429	1,591
End of period	$1,818	$ 1,782

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

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Quarter Ended March 31,	
	2004	2003 (Restated)
Net loss	$(206)	$(431)
Foreign currency translation adjustments	14	58
Unrealized net gains (losses) from cash flow hedging activity		
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $10 in 2004 and $23 in 2003)	(19)	53
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $8 in 2004 and $22 in 2003)	15	(46)
Other comprehensive income	10	65
Comprehensive loss	$(196)	$(366)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Events Update

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the U.S. 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 Quarterly Report on Form 10-Q along with our 2003 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2004, and for the quarters ended March 31, 2004 and 2003, are unaudited. We derived the balance sheet as of December 31, 2003, from the audited balance sheet filed in our 2003 Annual Report on Form 10-K. 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. Our results for the quarter ended March 31, 2003 have been restated to reflect the accounting impact of a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges, primarily those associated with our anticipated natural gas production. These restatements are further discussed in our 2003 Annual Report on Form 10-K. In addition, the prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications had no effect on our previously reported net income or stockholders' equity.

Business Update

In December 2003, our management presented its Long-Range Plan for the Company. This plan, among other things, defined our core businesses, established a timeline for debt reductions and sales of non-core businesses and assets and set financial goals for the future. During 2004, and through the filing date of this Form 10-Q, we have made significant progress in the areas outlined in that plan, including:

- completing or announcing sales of assets and investments of approximately $3.3 billion (see Note 4);
- retiring or refinancing approximately $1.8 billion of maturing debt and other obligations($576 million through March 31, 2004) (see Note 12);
- eliminating debt of $887 million ($72 million through March 31, 2004) through the sale of assets to which the debt related (see Note 12); and
- finalizing the Western Energy Settlement, which substantially resolved our principal exposure relating to the western energy crisis and successfully raising funds to satisfy a significant portion of our current obligations under that settlement (see Note 13).

Liquidity Update

We believe that the restatements of our historical financial statements discussed above would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions; specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension of time from various lenders until November 30, 2004 to file our second quarter 2004 Form 10-Q, which we expect to meet. If we are unable to file our second quarter 2004 Form 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our revolving credit facility and various other transactions could be accelerated. As part of obtaining our waivers, we also amended various provisions of the revolving credit facility, including provisions related to events of default and limitations on our ability, as well as that of our subsidiaries, to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our revolving credit facility could constitute an event of default under some of our other debt agreements. 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.

Our $3 billion revolving credit facility matures on June 30, 2005. The facility is collateralized by our equity interests in Tennessee Gas Pipeline Company (TGP), El Paso Natural Gas Company (EPNG), ANR Pipeline Company (ANR), Colorado Interstate Gas Company (CIG), Wyoming Interstate Company (WIC), Southern Gas Storage Company, ANR Storage Company, as well as our common interests in Enterprise, as further described below. With the sale of a majority of our interests in GulfTerra Energy Partners, L.P. (GulfTerra) to Enterprise Products Partners, L.P. (Enterprise) in September 2004, which included all of our Series C and some of our common units, our borrowing capacity under this facility was reduced by approximately $456 million to approximately $2.5 billion in October 2004. Upon the closing of the merger of GulfTerra and Enterprise, our remaining interests in GulfTerra's common units were converted into Enterprise common units, which continue to collateralize this facility. We are in the process of negotiating the refinancing of this facility as the combination of a $1.75 billion, three year revolving credit facility and a five year term loan of up to $1.25 billion and currently expect to be successful in this refinancing. In the event we are unable to refinance our revolving credit facility by June 30, 2005, we would be obligated to repay any outstanding amounts, and make alternative arrangements for the letters of credit issued pursuant to this credit facility. As of September 30, 2004, we had no borrowings outstanding and had approximately $1.1 billion of letters of credit issued under this credit facility.

Although we expect to successfully refinance all or a portion of our existing revolving credit facility, if we were unsuccessful, we believe we could adjust our planned capital expenditures and increase our planned asset sales to meet any shortfall in liquidity, and at the same time provide for our operations. Further, if we repaid our obligations under the revolving credit facility, some of the assets that currently collateralize this facility, including our equity interests in TGP, EPNG, ANR, CIG, WIC Southern Gas Storage Company, ANR Storage Company and our common units in Enterprise, could be used to support new financing transactions. Although we cannot guarantee the outcome of future events, we believe that this available collateral would be adequate to provide financing sufficient to meet our liquidity needs.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived its financial filing requirements through December 31, 2004. The filing of our second quarter 2004 Form 10-Q and the first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the events of non-compliance resulting from the failure to file financial statements. In addition, neither we nor any of our subsidiaries have received a notice of the default caused by our failure to file financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

Furthermore, the material restatements of our financial statements for the period ended December 31, 2001 as was reported in our 2003 Annual Report on Form 10-K could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004.

Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

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 to do so under their financing agreements and indentures. Under the cash management program, depending on whether participating subsidiaries have short-term cash requirements or surpluses, we either provide cash to them or they provide cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to us via our cash management program due to its anticipated cash needs. In addition, our ownership in a number of our subsidiaries and investments serves as collateral under our revolving credit facility and our other financings. If the lenders under the credit facility or those other financings were to exercise their rights to this collateral, we could lose our ownership interest in these subsidiaries or be required to liquidate these investments.

If, as a result of the events described above, we were subject to voluntary or involuntary bankruptcy proceedings, our creditors could attempt to make claims against our subsidiaries, including claims to substantively consolidate those subsidiaries. We believe that claims to substantively consolidate our subsidiaries would be without merit. However, there is no assurance that our creditors would not advance such a claim in a bankruptcy proceeding. If our creditors were able to substantively consolidate our subsidiaries, it could have a material adverse effect on our financial condition and our liquidity.

We believe we will be able to meet our ongoing liquidity and cash needs through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our revolving credit facility, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, and common or preferred equity securities. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans.

2. Significant Accounting Policies

Our significant accounting policies are discussed in our 2003 Annual Report on Form 10-K. The information below provides updating information or required interim disclosures with respect to those policies or disclosure where our policies have changed.

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 loss and loss per share had we applied SFAS No. 123 for the quarters ended March 31:

	2004	2003
	(In millions)	
Net loss, as reported	$ (206)	$ (431)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	4	11
Deduct: Total stock-based employee compensation determined under fair value-based method for all awards, net of taxes	10	27
Pro forma net loss	$ (212)	$ (447)
Loss per share:		
Basic and diluted, as reported	$(0.32)	$(0.72)
Basic and diluted, pro forma	$(0.33)	$(0.75)

Consolidation of Variable Interest Entities

In January 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. In December 2003, the FASB issued FIN No. 46-R, which amended FIN No. 46 to extend its effective date until the first quarter of 2004 for all types of entities, except special purpose entities. In addition, FIN No. 46-R limited the scope of FIN No. 46 to exclude certain joint ventures or other entities that meet the characteristics of businesses.

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 $12 million of third party debt as of March 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 $31 million as of March 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. These entities consist primarily of 25 equity investments held in our Power segment that have interests in power generation and transmission facilities with a total generating capacity of approximately 8,100 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 ($1.7 billion as of March 31, 2004) and our guarantees and other agreements associated with these entities (a maximum of $221 million as of March 31, 2004).

During our adoption of FIN 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 250 gross MW power facilities and are obligated to market the power generated by those facilities. In addition, we pay that entity a capacity charge that ranges from $25 million to $30 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 quarters ended March 31:

	2004	2003
	(In millions)	
Operating revenues	$ 15	$ 38
Non-current assets from price risk management activities	18	—
Current liabilities from price risk management activities	(30)	(10)
Non-current liabilities from price risk management activities	—	(68)

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. This standard required that we record a liability for retirement and removal costs of long-lived assets used in our businesses. In the first quarter of 2003, we recorded a charge as a cumulative effect of an accounting change of approximately $9 million, net of income taxes related to its adoption.

New Accounting Pronouncement Not Yet Adopted

In September 2004, the SEC issued Staff Accounting Bulletin No. 106. This pronouncement will require companies that use the full cost method for accounting for their oil and gas producing activities to include an estimate of future asset retirement costs to be incurred as a result of future development activities on proved reserves in their calculation of depreciation, depletion and amortization. This pronouncement will also require these companies to exclude any future cash outflows associated with settling asset retirement liabilities from their full cost ceiling test calculation. This standard will also require these companies to disclose the impact of their asset retirement obligations on their oil and gas producing activities, ceiling test calculations and depreciation, depletion and amortization calculations. We will adopt the provisions of this pronouncement in the fourth quarter of 2004 and are currently evaluating its impact, if any, on our consolidated financial statements.

3. Acquisitions and Consolidations

Chaparral Investors, L.L.C. As discussed more completely in our 2003 Annual Report on Form 10-K, we acquired Chaparral in a series of transactions (also referred to as a step acquisition). We reflected Chaparral's results of operations in our income statement as though we acquired it on January 1, 2003. Although this did not change our reported net income for the first quarter of 2003, it did impact the individual components of our income statement by increasing our revenues by $76 million, operating expenses by $80 million, earnings (losses) from unconsolidated affiliates by $55 million, interest expense by $67 million and decreasing distributions on preferred interests in subsidiaries by $18 million and other income by $2 million.

During the first quarter of 2003, as a result of an additional investment in Limestone Electron Trust (Limestone), coupled with a number of developments including a general decline in power prices, declines in our credit ratings as well as those of our counterparties, adverse developments at several of Chaparral's projects, our announced exit from the power contract restructuring business and generally weaker economic conditions in the unregulated power industry, we determined that the fair value of Chaparral (based on its discounted expected net cash flows) was less than our carrying value of the investment. As a result, we recorded an impairment of $207 million on Chaparral, before income taxes, during the quarter ended March 31, 2003.

4. Divestitures

Sales of Assets and Investments

During 2004, 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:

Significant Assets and Investments Sold	Completed Through March 31, 2004	Completed After March 31, 2004 or Announced to Date[(1)]	Total
		(In millions)	
Regulated			
Pipelines	$ 2	$ 52	$ 54
• Australia pipelines[(2)]			
• Equity interest in gathering systems[(2)]			
• Aircraft[(3)]			
Unregulated			
Production	352	58	410
• Natural gas and oil properties in Canada[(4)]			
• International exploration and production assets[(2)]			
Power	6	870	876
• 25 domestic power plants under contract for sale[(5)]			
• Utility Contract Funding (UCF)[(2)]			
• Mohawk River Funding IV[(3)]			
• Equity interest in the Bastrop Company power investment[(2)]			
• 5 other domestic power plants and turbines[(2)]			
Field Services	—	1,026	1,026
• Effective ownership of 50 percent of general partnership interest, approximately 2.9 million common units and all Series C units of GulfTerra[(2)]			
• South Texas processing plants[(2)]			
Other			
Corporate	8	8	16
• Aircraft			
Total continuing	368[(6)]	2,014	2,382
Discontinued	891	14	905
• Aruba and Eagle Point refineries[(3)]			
• Other petroleum assets[(2)]			
Total	$1,259	$2,028	$3,287

(1) Sales that have not been completed are estimates, subject to customary regulatory approvals, final negotiations and other conditions.
(2) These sales were completed after March 31, 2004.
(3) These sales were completed as of March 31, 2004.
(4) We sold all of our Canadian onshore natural gas and oil properties in the first quarter of 2004. We sold our interests in Nova Scotia in the third quarter of 2004.
(5) The sales of 22 of these plants were completed after March 31, 2004.
(6) 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 $11 million for the quarter ended March 31, 2004.

Significant Assets and Investments Sold	Proceeds (In millions)
As of March 31, 2003	
Regulated	
Pipelines	$ 43
• Panhandle gathering system located in Texas	
• 2.1 percent equity interest in Alliance pipeline and related assets	
Unregulated	
Production	678
• Natural gas and oil properties in western Canada, New Mexico, Oklahoma and the Gulf of Mexico	
Power	264
• 50 percent equity interest in CE Generation L.L.C. power investment	
• Mt. Carmel power plant	
• Equity interest in Kladno power project	
Field Services	35
• Gathering systems located in Wyoming	
Other	
Corporate	30
• Aircraft	
Total continuing	1,050[(1)]
Discontinued	515
• Corpus Christi refinery	
• Florida petroleum terminals and tug and barge operations	
• Coal reserves and properties in West Virginia, Virginia and Kentucky	
Total	$1,565

(1) Proceeds include costs incurred in preparing assets for disposal and exclude returns of invested capital and cash transferred with the assets sold. These items increased our sales proceeds by $19 million for the quarter ended March 31, 2003.

See Notes 6 and 17 for a discussion of gains, losses and asset impairments related to the sales above.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets being disposed of as held for sale or, if appropriate, discontinued operations if they have received appropriate approvals by our management or Board of Directors and have met other criteria. The following table details the items that have been reflected as current assets and liabilities held for sale in our balance sheets as of March 31, 2004 and December 31, 2003.

	March 31, 2004	December 31, 2003
	(In millions)	
Assets Held for Sale		
Current assets	$ 43	$ 44
Assets from price risk management activities, current	2	2
Investments in unconsolidated affiliates	474	480
Property, plant and equipment, net	465	477
Assets from price risk management activities, non-current	14	11
Intangible assets, net	11	11
Other assets	116	114
Total assets	$1,125	$1,139
Current liabilities	$ 55	$ 54
Long-term debt, less current maturities	167	169
Other liabilities	12	13
Total liabilities	$ 234	$ 236

In August 2004, our Board of Directors authorized the sale of our Indian Springs natural gas gathering and processing assets in our Field Services segment. We currently expect to incur an impairment charge of approximately $13 million related to these assets, and will classify them as assets held for sale subsequent to March 31, 2004.

Discontinued Operations

Petroleum Markets. During the first quarter of 2003, our Board of Directors approved the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. In June 2003, our Board of Directors authorized the sale of our remaining petroleum markets operations, including our Aruba refinery, 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 a pre-tax impairment charge of $350 million during the first quarter of 2003 related primarily to our Eagle Point refinery and several of our chemical 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 $55 million in the first quarter of 2003 from the sale of our Corpus Christi refinery and Florida terminalling and marine assets.

In the first and second quarters of 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 expect to complete the sale of our remaining petroleum markets operations in 2004. In addition, in the first quarter of 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. 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.

In the second quarter of 2004, our Board of Directors approved exiting our Canadian and other international natural gas and oil operations. We will report these operations as discontinued operations beginning in the second quarter of 2004, which will not have a material impact to our balance sheet.

Our petroleum markets and coal mining operations 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 March 31, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	Coal Mining	Total
		(In millions)	
Operating Results Data			
Quarter Ended March 31, 2004			
Revenues	$ 639	$ —	$ 639
Costs and expenses	(653)	—	(653)
Loss on long-lived assets	(42)	—	(42)
Other expense	(2)	—	(2)
Interest and debt expense	(3)	—	(3)
Loss before income taxes	(61)	—	(61)
Income taxes	(6)	—	(6)
Loss from discontinued operations, net of income taxes	$ (55)	$ —	$ (55)
Quarter Ended March 31, 2003			
Revenues	$ 2,168	$ 27	$ 2,195
Costs and expenses	(2,132)	(21)	(2,153)
Loss on long-lived assets	(296)	(3)	(299)
Other income	7	1	8
Income (loss) before income taxes	(253)	4	(249)
Income taxes	(28)	1	(27)
Income (loss) from discontinued operations, net of income taxes	$ (225)	$ 3	$ (222)

	Petroleum Markets	
	March 31, 2004	December 31, 2003
	(In millions)	
Financial Position Data		
Assets of discontinued operations		
Accounts and notes receivables	$ 69	$ 259
Inventory	5	385
Other current assets	31	131
Property, plant and equipment, net	26	521
Other non-current assets	26	70
Total assets of discontinued operations	$157	$1,366
Liabilities of discontinued operations		
Accounts payable	$ 12	$ 172
Other current liabilities	18	86
Long-term debt	—	374
Other non-current liabilities	6	26
Total liabilities of discontinued operations	$ 36	$ 658

5. Restructuring Costs

As a result of actions taken in 2003 and 2004, we incurred organizational restructuring costs included in our operation and maintenance expense. By segment, these charges were as follows:

	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate	Total
			(In millions)				
2004							
Employee severance, retention and transition costs	$ 4	$ 9	$ 2	$ 3	$ 1	$ 8	$ 27
2003							
Employee severance, retention and transition costs	$ —	$ 3	$ 1	$ 3	$ —	$ 18	$ 25
Contract termination costs	—	—	—	—	—	44	44
	$ —	$ 3	$ 1	$ 3	$ —	$ 62	$ 69

Our 2004 restructuring costs consisted of employee severance costs which included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. During the first quarter of 2004, we eliminated approximately 350 full-time positions from our continuing businesses and approximately 1,100 positions related to discontinued businesses. As of September 30, 2004, substantially all of the 2004 employee severance, retention and transition costs had been paid.

Our 2003 restructuring costs were incurred as part of our ongoing liquidity enhancement and cost reduction efforts. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. The contract termination costs consisted of $44 million related to amounts paid for canceling or restructuring our obligations for chartering ships to transport liquefied natural gas (LNG) from supply areas to domestic and international market centers.

Office Relocation and Consolidation

In May 2004, we began consolidating our Houston-based operations into one location. We anticipate the consolidation will be substantially complete by the end of 2004. As a result, we will establish an accrual to record a liability for our obligations under the terms of the vacated leases in the period that the space is available for subleasing. We currently lease approximately 912,000 square feet of office space in the buildings we are vacating under various leases with terms that expire in 2004 through 2014. We estimate the total accrual for our liability will be approximately $80 million to $100 million. At the time the decision was made to consolidate our Houston-based operations, approximately 26,000 square feet was vacant and available for subleasing at which time we accrued an obligation of approximately $1 million. During the third quarter of 2004, we vacated approximately 211,000 square feet and recorded a liability of approximately $30 million. In addition, we subleased approximately 125,000 square feet in the third quarter of 2004. Approximately $3 million in actual moving expenses related to the relocation will be expensed in the period that they are incurred. These amounts will be reflected in our Corporate operations.

6. 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, goodwill and other intangibles that are a part of our continuing operations. During each of the quarters ended March 31, our loss on long-lived assets was as follows:

	2004	2003
	(In millions)	
Net realized loss	$ 77	$ 4
Asset impairments		
Power	228	—
Production	8	9
Field Services	2	—
Corporate	—	9
Total asset impairments	238	18
Loss on long-lived assets	$315	$22

Net Realized Loss

Our 2004 net realized loss was primarily related to an $85 million loss associated with the sale of natural gas and oil properties in Canada in our Production segment. Our 2003 net realized loss was primarily related to an $8 million realized loss related to the sale of an aircraft in our Corporate operations, partially offset by a $4 million realized gain associated with the sale of the Mt. Carmel power plant in our Power segment.

Asset Impairments

Our 2004 asset impairments primarily occurred in our Power segment, which included a $98 million impairment related to the sale of our subsidiary, UCF, which owns a restructured power contract and a $135 million impairment related to our Manaus and Rio Negro power plants in Brazil. The impairments in Brazil were primarily due to events in the first quarter of 2004 that may make it difficult to extend their power sales agreements that expire in 2005 and 2006. See Note 13 for a further discussion of these matters. Our Production segment also incurred an $8 million impairment in 2004 on a Canadian asset that was not part of our full cost pool. Our 2003 impairment charges related to the sale of non-full cost pool assets in Canada and an impairment of LNG assets due to our plan to reduce our involvement in this business.

7. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to determine whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects.

For the quarter ended March 31, 2004, we recorded ceiling test charges of approximately $24 million and $4 million related to our Canadian and Indonesian full cost pools. During the first quarter of 2004, we sold all of our Canadian onshore natural gas and oil properties. The ceiling test charge in Canada related to our remaining operations in Nova Scotia where, in the first quarter of 2004, we drilled an exploratory well that was not commercially viable.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in performing our ceiling test calculations and will be factored into future ceiling test calculations. The charges for our international full cost pools would not have materially changed had the impact of our hedges not been included in calculating our ceiling test charges since we do not significantly hedge our international production activities.

8. Income Taxes

Our income tax benefit and effective income tax rate were $44 million and 23 percent for the quarter ended March 31, 2004, compared to an income tax benefit and effective income tax rate of $106 million and 35 percent for the quarter ended March 31, 2003. 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 the first quarter of 2004, our overall effective tax rate on continuing operations was lower than the statutory rate due primarily to the impairments of certain of our foreign investments for which there is no corresponding tax benefit.

For the year ended December 31, 2004 we currently expect our effective tax rate to be significantly different from the statutory rate of 35 percent based on the closing of the GulfTerra transaction in September 2004. The sale of our interests in GulfTerra will result in a significant tax gain (versus a much lower book gain) and significant tax expense due to the non-deductibility of goodwill written off as a result of the transaction. We believe the impact of this non-deductible goodwill will increase our tax expense (or reduce our tax benefit) by approximately $139 million.

Proposed tax legislation has been introduced in the U.S. Senate which would disallow deductions for certain settlements made to or on behalf of governmental entities. 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 assets. In such event, our tax expense would increase. Our total tax assets related to the Western Energy Settlement were $400 million as of March 31, 2004.

9. Earnings Per Share

Our basic and diluted loss per share were as follows for the quarters ended March 31:

	2004	2003
	(In millions, except per common share amounts)	
Loss from continuing operations	$ (151)	$ (200)
Discontinued operations, net of income taxes	(55)	(222)
Cumulative effect of accounting changes, net of income taxes	—	(9)
Net loss	$ (206)	$ (431)
Average common shares outstanding	638	595
Losses per common share		
Loss from continuing operations	$(0.23)	$(0.33)
Discontinued operations, net of income taxes	(0.09)	(0.37)
Cumulative effect of accounting changes, net of income taxes	—	(0.02)
Net loss	$(0.32)	$(0.72)

For both of the quarters ended March 31, 2004 and March 31, 2003, there were a total of 16 million of potentially dilutive securities excluded from the determination of average common shares outstanding because we had net losses from continuing operations in these periods. The excluded securities included stock options, trust preferred securities and convertible debentures.

10. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of March 31, 2004 and December 31, 2003. 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.

	March 31, 2004	December 31, 2003
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (35)	$ (31)
Derivatives from power contract restructuring activities	1,823[1]	1,925
Other commodity-based derivative contracts	(525)	(488)
Total commodity-based derivatives	1,263	1,406
Interest rate and foreign currency hedging derivatives[2]	124	123
Net assets from price risk management activities[3]	$1,387	$1,529

(1) Includes $864 million of assets from derivative contracts that we sold in the second quarter of 2004. See Note 6 for a discussion of the impairment related to this sale.

(2) During the quarter ended March 31, 2004, we entered into new cross currency hedge transactions that convert €50 million of our fixed rate Euro-denominated debt into $61 million of floating rate debt. After March 31, 2004, we entered into other cross currency hedge transactions that convert another €50 million of fixed rate debt into $60 million of floating rate debt.

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

11. Inventory

We have the following inventory on our balance sheets:

	March 31, 2004	December 31, 2003
	(In millions)	
Materials and supplies and other	$142	$148
Natural gas liquids and natural gas in storage	28	36
Total current inventory	$170	$184

12. Debt, Other Financing Obligations and Other Credit Facilities

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

	March 31, 2004	December 31, 2003
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 1,417	$ 1,401
Short-term financing obligations	55	56
Total short-term financing obligations	$ 1,472	$ 1,457
Long-term financing obligations	$19,681	$20,275

Long-Term Financing Obligations

From January 1, 2004 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Principal	Net Proceeds/ Repayments in Debt	Due Date
			(In millions)		
Issuances					
Macae	Note	LIBOR + 4.25%	$ 50	$ 50	2007
Repayments					
El Paso CGP	Note	LIBOR + 3.5%	$ 200	$ 200	
El Paso	Revolver	LIBOR + 3.5%	250	250	
Other	Long-term debt	Various	126	126	
	Repayments through March 31, 2004		576	576	
El Paso CGP	Note	6.2%	190	190	
Gemstone	Notes	7.71%	202	202	
El Paso	Revolver	LIBOR + 3.5%	600	600	
Lakeside	Note	LIBOR + 3.5%	42	42	
El Paso CGP	Notes	10.25%	38	38	
Other	Long-term debt	Various	143	143	
			$1,791	$1,791	

Company	Type	Interest Rate	Principal	Net Change in Debt	Due Date
			(In millions)		
Other Changes in Debt					
Blue Lake Gas Storage[1]	Term loan	LIBOR + 1.2%	$ 14	$ 14	2006
Mohawk River Funding IV[2]	Note	7.75%	(72)	(72)	
Other changes through March 31, 2004			(58)	(58)	
El Paso Power[3]	Non-recourse senior notes	7.944%	(815)	(815)	
El Paso Power	Capitalized lease	11.0%	(14)	(14)	
			$ (887)	$ (887)	

(1) This debt was consolidated as a result of adopting FIN 46 (see Note 2).

(2) This debt was eliminated when we sold our interest in Mohawk River Funding IV.

(3) This debt was eliminated when we sold our interests in UCF.

In October 2004, we entered into an agreement, effective August 2004, with two affiliates of Enron that would liquidate two existing swap agreements in exchange for approximately $213 million of 6.5%, one year notes. The transaction is pending approval by the bankruptcy court. As of March 31, 2004, the balance of these swaps was a liability of $245 million, which is reflected in other current and other non-current liabilities in our balance sheet.

Credit Facilities

We maintain a $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. This credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on the unused amounts of the facility. This revolving credit facility and other financing arrangements are collateralized by our ownership in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company, Southern Gas Storage Company, as well as our common units in Enterprise, as further described below. With the sale of a majority of our interests in GulfTerra to Enterprise in September 2004, which included all of our Series C and some of our common units, our borrowing capacity under this facility was reduced by approximately $456 million to approximately $2.5 billion in October 2004. Upon the closing of the merger of GulfTerra and Enterprise, our remaining interests in GulfTerra's common units were converted into Enterprise's common units which continue to collateralize this facility. Amounts outstanding under the revolving credit facility as of March 31, 2004, are classified as non-current in our balance sheet, based on the facility's maturity date. As of March 31, 2004, there were $600 million of borrowings outstanding and approximately $1.1 billion of letters of credit issued under the facility. In September 2004, we repaid the remaining $600 million outstanding under this facility. As of September 30, 2004, our borrowing availability under this facility was $1.8 billion. We are in the process of negotiating the refinancing of this facility as the combination of a $1.75 billion three year revolving credit facility and a five year term loan of up to $1.25 billion and currently expect to be successful in this refinancing.

The availability of borrowings under the revolving credit facility and other borrowing agreements is subject to various conditions described below, 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.

Restrictive Covenants

Our restrictive covenants are discussed in our 2003 Annual Report on Form 10-K. For an update of matters that have or could impact these covenants, including the restatement of our historical financial statements and associated waivers obtained, see Note 1, Liquidity Update of this Quarterly Report on Form 10-Q.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of March 31, 2004, we had outstanding letters of credit of approximately $1.2 billion. Of the letters of credit outstanding, approximately $1.1 billion was outstanding under our revolving credit facility. Included in this amount were $0.6 billion of letters of credit securing our recorded obligations related to price risk management activities. Of the outstanding letters of credit, $72 million was supported with cash collateral.

13. Commitments and Contingencies

Legal Proceedings and Government Investigations

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 to resolve the principal litigation, 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 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 to provide structural relief to the settling parties. In the JSA, we agreed to do the following:

- Subject to the conditions in the settlement; (1) make 3.29 Bcf/d of primary firm pipeline capacity on our EPNG system available to California delivery points during a five year period from the date of settlement, but only if shippers sign firm contracts for 3.29 Bcf/d of capacity with California delivery points; (2) maintain facilities sufficient to deliver 3.29 Bcf/d to the California delivery points; and (3) not add any firm incremental load to our EPNG system that would prevent it from satisfying its obligation to provide this capacity;

- Construct a new 320 MMcf/d, Line 2000 Power-Up expansion project and forego recovery of the cost of service of this expansion until EPNG's next rate case before the FERC;

- Clarify the rights of Northern California shippers to recall some of EPNG's system capacity (Block II capacity) to serve markets in PG&E's service area; and

- With limited exceptions, 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, we filed the JSA described above with the FERC in resolution of the CPUC complaint proceeding discussed below. 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.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. In the second quarter of 2003, we recorded an additional pretax charge of $104 million, based upon reaching definitive settlement agreements, and also established an escrow account for amounts to be funded by us under this settlement upon final approval by various parties. As of March 31, 2004, we had funded $558 million to this escrow account which was reflected as an increase in restricted cash in our balance sheet and a reduction of our cash flows from investing activities. Included in this amount were $74 million of proceeds from the issuance of common stock in January 2004.

Below is an analysis of our obligations related to the Western Energy Settlement as of March 31, 2004 (amounts are discounted):

Remaining Obligations	Current	Long-Term	Total
		(In millions)	
Cash payments of $45 million/year for 20 years	$ 45	$357	$ 406
Price reduction on power supply contract	82	34	116
Proceeds from issuance of common stock	195	—	195
Other cash payments	349	—	345
Total	$671	$391	$1,062

Once effective in June 2004, $602 million was released to the settling parties, which includes the escrowed funds discussed above. The payment of $602 million will be reflected as a reduction of our cash flows from operations in the second quarter of 2004. After the release of these funds, our remaining obligation under the Western Energy Settlement consists of the price reduction under a power supply contract over its remaining term and the 20-year cash payment obligation indicated in the table above. 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 initial collateral requirement was approximately $592 million and will be reduced as payments under our 20 year obligation are made in the future. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 8.

We are also a defendant in a number of additional lawsuits, pending in several Western states, relating to various aspects of the 2000-2001 Western energy crisis. We do not believe these additional lawsuits, either individually or in the aggregate, will have a material impact on us.

CPUC Complaint Proceeding Docket No. RP00-241-000. In April 2000, the CPUC filed a complaint under Section 5 of the Natural Gas Act (NGA) with FERC alleging that EPNG's sale of approximately 1.2 Bcf of capacity to its affiliate, EPME, raised issues of market power and was a violation of the FERC's marketing affiliate regulations and asked that the contracts be voided. In the spring and summer of 2001, hearings were held before an ALJ to address the market power issue and the affiliate issue. On November 19, 2003, the FERC approved the JSA, which is part of the Western Energy Settlement and vacated the ALJ's initial decisions. That decision was upheld by the FERC in a rehearing order issued on March 30, 2004. On April 9, 2004, certain shippers appealed both FERC orders on this matter to the U.S. Court of Appeals for the District of Columbia Circuit.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our former officers. Eleven of these lawsuits are now consolidated in federal court in Houston before a single judge. The twelfth lawsuit, filed in the Southern District of New York, was dismissed in light of similar claims being asserted in the consolidated suits in Houston. The lawsuits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. Two shareholder derivative actions have also been filed which generally allege the same claims as those made in the consolidated shareholder class action lawsuits. One, which was filed in federal court in Houston in August 2002, has been consolidated with the shareholder class actions pending in Houston, and has been stayed. The second shareholder derivative lawsuit, filed in Delaware State Court in October 2002, generally alleges the same claims as those made in the consolidated shareholder class action lawsuit and also has been stayed. Two other shareholder derivative lawsuits are now consolidated in state court in Houston. Both generally allege that manipulation of California gas supply and gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Beginning in February 2004, seventeen purported shareholder class action lawsuits alleging violations of federal securities laws were filed against us and several individuals in federal court in Houston. The lawsuits generally allege that our reporting of natural gas and oil reserves was materially false and misleading. Each of these lawsuits recently has been consolidated into the shareholder lawsuits described in the immediately preceding paragraph. An amended complaint in this consolidated securities lawsuit was filed on July 2, 2004.

In September 2004, a new derivative lawsuit was filed in federal court in Houston against certain of El Paso's current and former directors and officers. The claims in this new derivative lawsuit are for the most part the same claims made in the July 2004 consolidated amended complaint in the securities lawsuit. The one distinction is that the new derivative lawsuit includes a claim for compensation disgorgement under Sarbanes-Oxley Act of 2002 against certain of the individually named defendants.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston 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 recently was amended to include allegations relating to our reporting of natural gas and oil reserves. Our costs and legal exposure related to this lawsuit are not currently determinable; however, we believe this matter will be covered by insurance.

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). Discovery is proceeding. 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 on April 10, 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. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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 our subsidiaries are currently one of several defendants in over 50 such lawsuits nationwide, which 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 generally 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 and claims are not currently determinable.

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 are cooperating 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 are also cooperating with the U.S. Attorney regarding an investigation of specific transactions executed in connection with our production 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 between EPME and the CFTC of the price reporting matter providing for the payment by EPME of a civil monetary penalty 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 into the matter.

CFTC Investigation. In April 2004, our affiliates elected to voluntarily cooperate with the CFTC in connection with the CFTC's industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, our affiliates provided information relating to storage reports provided to the Energy Information Administration for the period of October 2003 through December 2003. On August 30, 2004, the CFTC announced they had completed the investigation and found no evidence of wrongdoing.

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 Nation's 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. Recent press reports indicate that other government entities, including various Congressional committees, are investigating the Oil for Food Program. We received inquiries from one of these committees.

On September 30, 2004, the Special Advisor to the Director of Central Intelligence issued a report on the Iraqi regime, including the Oil for Food Program. In part, the report found that the Iraqi regime earned kick backs or surcharges associated with the Oil for Food Program. The report did not name U.S. companies or individuals for privacy reasons, but according to various news reports congressional sources have identified The Coastal Corporation and the former chairman and CEO of Coastal, among others, as having purchased Iraqi crude during the period when allegedly improper surcharges were assessed by Iraq.

We are continuing in the process of collecting and reviewing documents responsive to the subpoena.

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. On June 20, 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.

On November 1, 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. On April 2, 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 personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All of these lawsuits have been settled, with settlement payments fully covered by insurance. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to four of the settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas on November 20, 2002, seeking additional sums based upon their interpretation of earlier settlement agreements. This matter has been settled and dismissed. In addition, a lawsuit entitled *Baldonado et. al. v. EPNG* was filed on June 30, 2003 in state court in Eddy County, New Mexico on behalf of 23 firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. This case was dismissed by the trial court. The appeals court initially issued a notice dismissing all claims. This decision was appealed and the appeals court has agreed to hear this matter. Briefs will be filed by the end of this year. Our costs and legal exposure related to the *Baldonado* lawsuit are not currently determinable, however we believe this matter will 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.

For each of our outstanding legal 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. 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 current reserves are adequate. As of March 31, 2004, we had approximately $1.2 billion accrued for all outstanding legal matters, which includes the accruals related to 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 March 31, 2004, we had accrued approximately $401 million, including approximately $394 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 $401 million accrual, $158 million was reserved for facilities we currently operate, and $243 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 $401 million to approximately $591 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 ($97 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($304 million to $494 million) and if no one amount in that range is more likely than any other, the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	March 31, 2004	
Sites	Expected	High
	(In millions)	
Operating	$158	$225
Non-operating	212	321
Superfund	31	45
Total	$401	$591

Below is a reconciliation of our accrued liability from January 1, 2004, to March 31, 2004 (in millions):

Balance as of January 1, 2004	$412
Payments for remediation activities	(10)
Other changes, net	(1)
Balance as of March 31, 2004	$401

For 2004, we estimate that our total remediation expenditures will be approximately $57 million. In addition, we expect to make capital expenditures for environmental matters of approximately $86 million in the aggregate for the years 2004 through 2008. 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 March 31, 2004, TGP had pre-collected PCB costs by approximately $121 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 March 31, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $90 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 62 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 March 31, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $45 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 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 reserves are adequate.

Other

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. We sold $244 million of the original claims to a third party. Enron also maintained that El Paso Merchant Energy-Petroleum Company owed it approximately $3 million, and that EPME owed EPMI $46 million, each due to the termination of petroleum and physical power contracts. In both cases, we maintained that due to contractual setoff rights, no money was owed to the Enron parties. Additionally, EPME maintained that EPMI owed EPME $30 million due to the termination of the physical power contract, which is included in the $317 million of filed claims. EPMI filed a lawsuit against EPME and its guarantor, El Paso Corporation, based on the alleged $46 million liability. On June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved all of the foregoing issues as well as most other trading or merchant issues between the parties. Our European trading businesses also asserted $20 million in 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 exposure to Enron is $3 million.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have 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. 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 the rejection date.

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 it 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.

Economic Conditions of Brazil. We own and have investments in power, pipeline and production assets in Brazil with an aggregate exposure, including financial guarantees, of approximately $1.5 billion. During 2002, Brazil experienced declines in its financial markets, which contributed to significantly higher interest rates in 2002 on local debt for the government and private sectors, significantly decreased the availability of funds from lenders outside of Brazil and decreased the amount of foreign investment in the country. During late 2003 and 2004, Brazil's general economic conditions improved, although Brazil continues to experience high debt and interest rate levels that need to be improved in order to stabilize its economy. In addition, the government may impose or attempt to impose changes that could affect our investments, including imposing price controls on electricity and fuels, attempting to force renegotiation of power purchase agreements (PPA's) which provide for partial protection from local currency devaluation or attempting to impose other concessions. These developments have delayed and may continue to delay the implementation of project financings planned and underway in Brazil (although we have raised $420 million of non-recourse debt on our Macae power project through 2004). We currently believe that the economic difficulties in Brazil will not have a future material adverse effect on our investment in the country, but we continue to monitor the economic situation and potential changes in governmental policy, and are working with the state-controlled utilities in Brazil that are counterparties under our projects' PPA's to attempt to maintain the economic returns we anticipated when we made our investments. Some of the specific difficulties we are experiencing in Brazil are discussed below.

We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The project company in which we have an ownership interest has a 20-year PPA with a regional utility that is currently in international arbitration and in litigation in Curitiba courts. 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 $181 million at March 31, 2004. Based on the future outcome of our dispute under the PPA, we could be required to write down the value of our investment.

We own two projects located in Manaus, Brazil. The first project is a 238 MW fuel-oil fired plant known as the Manaus Project, which has a net book value of $34 million at March 31, 2004 and the second project is a 158 MW fuel-oil fired plant known as the Rio Negro Project with a net book value of $40 million at March 31, 2004. The Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. In the first quarter of 2003, the Manaus Project began experiencing delays in payment from the purchaser of our power, Manaus Energia S.A. In the fourth quarter of 2003, all of the contractual issues were resolved and a payment schedule was established and is being followed for all payments in arrears. These past due payments were collected as of March 2004. As of March 31, 2004, our accounts receivable on the Manaus Project is $4 million. In addition, we have filed a lawsuit in the Brazilian courts against Manaus Energia on the Rio Negro Project regarding a tariff dispute related to power sales from 1999 to 2003 and have an additional long-term receivable of $32 million which is a subject of this lawsuit. As a result of changes in the Brazilian political environment in early 2004, Manaus Energia issued a request for power supply proposals for 450 MW to 525 MW of net generating capacity from 2005 to 2006. The bid qualifications issued by Manaus Energia may prohibit us from supplying power from our Manaus and Rio Negro projects. We have filed both administrative and legal challenges to these bid qualifications and intend to submit a bid. A non-governmental organization has obtained a preliminary injunction enjoining Manaus Energia from proceeding with the bid process until a decision on the merits of their complaint is made. Based on the expected results of the bid process and its impact on the future outcome of any negotiations to extend the term of the PPA's, we recorded an impairment charge of approximately $135 million in the first quarter of 2004. Based on the future outcome of the lawsuit related to the $32 million receivable, we could be required to provide an allowance for the receivable discussed above.

We own a 50 percent interest in a 404 MW dual-fuel-fired power project known as the Porto Velho Project, located in Porto Velho, Brazil. The Porto Velho Project has two PPA's. The first PPA has a term of ten years and relates to the first phase of the project. The second PPA has a term of 20 years and relates to the second 345 MW phase of the project. We are negotiating certain provisions of both PPA's with EletroNorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. Although the current terms of the PPA's 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 at March 31, 2004, was $291 million.

We own a 895 MW gas-fired power project known as the Macae project located near the city of Macae, Brazil with a net book value of $732 million at March 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 guaranteed by Petrobras until August 2007 under a participation agreement. Recently Petrobras has requested that certain provisions of the participation agreement, particularly the terms of the capacity payment, be renegotiated and we have begun early discussions with Petrobras. While the current terms of the participation agreement do not indicate an impairment of our investment, a renegotiation of the participation agreement could reduce our earnings from this project beginning in 2005 and we may be required to write down the value of our investment at that time.

While the outcome of these matters cannot be predicted with certainty 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. The impact of these changes may have a material effect on our results of operations, our financial position and our cash flows in the periods these events occur.

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 2003 Annual Report on Form 10-K for a description of each type of guarantee. As of March 31, 2004, we had approximately $256 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 March 31, 2004, we had accrued $78 million related to these arrangements.

14. Retirement Benefits

The components of net benefit cost (income) for our pension and postretirement benefit plans for the quarters ended March 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Service cost	$ 8	$ 9	$—	$—
Interest cost	31	34	8	9
Expected return on plan assets	(48)	(57)	(3)	(2)
Amortization of net actuarial loss	12	1	1	—
Amortization of transition obligation	—	—	2	2
Amortization of prior service cost[(1)]	(1)	(1)	—	—
Settlements, curtailment, and special termination benefits	—	—	—	(6)
Net benefit cost (income)	$ 2	$(14)	$ 8	$ 3

[(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.

We made $15 million and $19 million of cash contributions to our Supplemental Executive Retirement Plan and other postretirement plans during the quarters ended March 31, 2004 and 2003. We expect to contribute an additional $2 million to the Supplemental Executive Retirement Plan and $48 million to our other postretirement plans in 2004. We do not anticipate making any other contributions to our other retirement benefit plans in 2004. We are currently evaluating the impact of the Pension Funding Equity Act enacted in 2004 on our projected funding.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. Benefit obligations and costs reported that are related to prescription drug coverage do not reflect the impact of this legislation. In addition, we are currently evaluating new accounting standards that become effective in the fourth quarter of 2004 that may require changes to our net benefit cost and to previously reported benefit information.

15. Capital Stock

Common Stock

In January 2004, we issued 8.8 million shares of common stock for $74 million to satisfy the remaining stock obligation under our Western Energy Settlement.

Dividends

During the quarter ended March 31, 2004, we paid dividends of $23 million to common stockholders. We have also paid dividends of $77 million subsequent to March 31, 2004. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit. In addition, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends (2.0625% per quarter 8.25% per annum)of approximately $6 million in each quarter of 2004 on its Series A cumulative preferred stock.

16. Segment Information

During 2004, we reorganized our business structure into two primary business lines, regulated and unregulated, 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 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 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 our continuing corporate operations. Our operating results for all periods presented reflect this change.

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 loss from continuing operations for the quarters ended March 31:

	2004	2003
	(In millions)	
Total EBIT	$ 233	$ 128
Interest and debt expense	(422)	(413)
Distributions on preferred interests of consolidated subsidiaries	(6)	(21)
Income taxes	44	106
Loss from continuing operations	$(151)	$(200)

The following tables reflect our segment results as of and for the quarters ended March 31:

	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2004							
Revenues from external customers	$698	$102[2]	$ 240	$ 149	$345	$ 43	$1,577
Intersegment revenues	23	372[2]	(399)	58	(3)	(43)	8[3]
Operation and maintenance	180	89	12	98	26	—	405
Depreciation, depletion and amortization	100	149	3	16	3	12	283
(Gain) loss on long-lived assets	(1)	93	—	224	2	(3)	315
Ceiling test charges	—	28	—	—	—	—	28
Operating income (loss)	$348	$ 94	$(175)	$(188)	$ 10	$ 7	$ 96
Earnings from unconsolidated affiliates	33	1	—	29	37	—	100
Other income (expense)	5	—	3	20	(11)	20	37
EBIT	$386	$ 95	$(172)	$(139)	$ 36	$ 27	$ 233
2003							
Revenues from external customers	$722	$257[2]	$ 149	$ 222	$401	$ 35	$1,786
Intersegment revenues	31	503[2]	(537)	20	157	(106)	68[3]
Operation and maintenance	176	91	44	165	31	55	562
Depreciation, depletion and amortization	95	164	7	20	10	23	319
(Gain) loss on long-lived assets	—	9	(1)	(6)	1	19	22
Ceiling test charges	—	1	—	—	—	—	1
Operating income (loss)	$384	$440	$(441)	$ (5)	$ —	$(111)	$ 267
Earnings (losses) from unconsolidated affiliates	43	6	—	(201)	28	(10)	(134)
Other income (expense)	2	3	7	10	(1)	(26)	(5)
EBIT	$429	$449	$(434)	$(196)	$ 27	$(147)	$ 128

(1) Includes our Corporate and telecommunications activities and 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 record an intersegment revenue elimination, which is the only elimination 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 petroleum markets operations.

Total assets by segment are presented below:

	March 31, 2004	December 31, 2003
	(In millions)	
Regulated		
Pipelines	$16,009	$15,753
Unregulated		
Production	4,048	4,205
Marketing and Trading	2,336	2,666
Power	6,589	7,074
Field Services	1,962	1,990
Total segment assets	30,944	31,688
Corporate	4,114	4,030
Discontinued operations	157	1,366
Total consolidated assets	$35,215	$37,084

17. 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. 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 $94 million for the quarter ended March 31, 2004 and $83 million for the quarter ended March 31, 2003 from our investments. Our proportionate share of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $14 million and $9 million for the quarters ended March 31, 2004 and 2003.

	Quarter Ended March 31, 2004		
	GulfTerra	Other Investments	Total
	(In millions)		
Operating results data:			
Operating revenues	$127	$457	$584
Operating expenses	81	304	385
Income from continuing operations[(1)]	31	81	112
Net income[(1)]	31	78	109

(1) We have also recorded minority interest expense in 2004 of $10 million related to the effective 50 percent general partner interest in GulfTerra acquired by Enterprise in December 2003.

	Quarter Ended March 31, 2003		
	GulfTerra	Other Investments	Total
	(In millions)		
Operating results data:			
Operating revenues	$188	$667	$855
Operating expenses	137	424	561
Income from continuing operations	28	143	171
Net income	28	143	171

Our income statement reflects our earnings (losses) from unconsolidated affiliates. This amount includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments to income we record. The table below reflects our earnings (losses) from unconsolidated affiliates for the quarters ended March 31:

	2004	2003
	(In millions)	
Proportional share of income of investees[1]	$109	$ 171
Impairment charges and gains and losses on sale of investments		
Chaparral[2]	—	(207)
Milford power facility[3]	(2)	(86)
Other impairments	(17)	(10)
Other	10	(2)
Total earnings (losses) from unconsolidated affiliates	$100	$(134)

(1) We have also recorded minority interest expense in 2004 of $10 million related to the effective 50 percent general partner interest in GulfTerra acquired by Enterprise in December 2003.

(2) This impairment resulted from other than temporary declines in the investment's fair value based on developments in our power business and the power industry (see Note 3).

(3) This impairment resulted from a write-off of notes receivable and accruals on contracts due to ongoing difficulty at the project level.

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates for the quarters ended March 31:

	2004	2003
	(In millions)	
Operating revenue	$ 73	$ (69)
Other revenue — management fees	2	2
Cost of sales	23	21
Reimbursement for operating expenses	30	36
Other income	3	3
Interest income	2	3
Interest expense	—	2

GulfTerra

Prior to 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 contributes to our income through our general partner interest and our ownership of common and preference units. We do not have any loans to or from GulfTerra.

We had the following interests in GulfTerra as of March 31, 2004:

	Book Value (In millions)	Ownership (Percent)
One Percent General Partner[1]	$194	100.0
Common Units[2]	249	17.8
Series C Units[3]	332	100.0
Total	$775	

(1) We had $181 million of indefinite-lived intangible assets related to our general partner interest and $96 million recorded as minority interest related to Enterprise's effective 50 percent ownership interest in the general partner as of March 31, 2004. Additionally, we had approximately $480 million of goodwill associated with our Field Services segment which was eliminated as a result of the completion of the Enterprise transaction discussed below.

(2) The remaining units are owned by public holders, including the partnership employees and management, none of which individually own more than 10 percent.

(3) As of March 31, 2004, we owned all of the Series C units of GulfTerra.

In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we completed the sale of substantially all of our interests in GulfTerra, as well as certain processing assets to affiliates of Enterprise. Our total gross cash proceeds from the sale were approximately $1.03 billion and we will record a gain of approximately $19 million as a result of this transaction including the elimination of approximately $480 million in goodwill associated with our Field Services segment. Of the $480 million of goodwill that was eliminated, approximately $397 million will not be deductible for tax purposes. As a result, we will recognize a significant tax gain and tax expense associated with the transaction in the third quarter of 2004. The assets sold were our interest in the general partner of GulfTerra, 10.9 million Series C units, 2.9 million GulfTerra common units, and nine processing plants located in South Texas. In addition to the cash proceeds, we received a 9.9 percent interest in the general partner of the combined organization, Enterprise Products GP, LLC. Our remaining GulfTerra common units were exchanged for approximately 13.5 million common units in Enterprise as a result of the merger.

Our segments also conduct transactions in the ordinary course of business with GulfTerra, including sales of natural gas and operational services. Below is the summary of our transactions with GulfTerra for the quarters ended March 31:

	2004	2003
	(In millions)	
Revenues received from GulfTerra		
Marketing and Trading	$ 9	$10
Field Services	1	5
	$10	$15
Expenses paid to GulfTerra		
Field Services	$19	$17
Marketing and Trading	8	11
Production	2	2
	$29	$30
Reimbursements received from GulfTerra		
Field Services	$22	$24

For a further discussion of our relationships with GulfTerra, see our 2003 Annual Report on Form 10-K.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2003 Annual Report on Form 10-K, and the financial statements and notes presented in Item 1 of this Form 10-Q.

Our results for the quarter ended March 31, 2003 have been restated to reflect the accounting impact of a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges, primarily those associated with our anticipated natural gas production as further discussed in our 2003 Annual Report on Form 10-K.

Overview

Business Update

In December 2003, our management presented its Long-Range Plan for the Company. This plan, among other things, defined our core businesses, established a timeline for debt reductions and sales of non-core businesses and assets and set financial goals for the future. During 2004, and through the filing date of this Form 10-Q, we have made significant progress in the areas outlined in that plan, including:

- completing or announcing sales of assets and investments of approximately $3.3 billion (see Note 4)
- retiring or refinancing approximately $1.8 billion of maturing debt and other obligations, ($576 million through March 31, 2004) (see Note 12);
- eliminating debt of $887 million ($72 million through March 31, 2004) through the sale of assets to which the debt related (see Note 12); and
- finalizing the Western Energy Settlement, which substantially resolved our principal exposure relating to the western energy crisis and successfully raising funds to satisfy a significant portion of our current obligations under that settlement (see Note 13).

Liquidity Update

We believe that the restatements of our historical financial statements discussed above would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions; specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension of time from various lenders until November 30, 2004 to file our second quarter 2004 Form 10-Q, which we expect to meet. If we are unable to file our second quarter 2004 Form 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our revolving credit facility and various other transactions could be accelerated. As part of obtaining our waivers, we also amended various provisions of the revolving credit facility, including provisions related to events of default and limitations on our ability, as well as that of our subsidiaries, to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our revolving credit facility could constitute an event of default under some of our other debt agreements. 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.

Our $3 billion revolving credit facility matures on June 30, 2005. The facility is collateralized by our equity interests in TGP, EPNG, ANR, CIG, WIC, Southern Gas Storage Company, ANR Storage Company, as well as our common units in Enterprise, as further described below. With the sale of a majority our interests in GulfTerra to Enterprise in September 2004, which included all of our Series C and some of our common units, our borrowing capacity under this facility was reduced by approximately $456 million to approximately $2.5 billion in October 2004. Upon the closing of the merger of GulfTerra and Enterprise, our remaining interests in GulfTerra's common units were converted into Enterprise common units, which continue to collateralize this facility. We are in the process of negotiating the refinancing of this facility as the combination of a $1.75 billion, three year revolving credit facility and a five year term loan of up to $1.25 billion and currently expect to be successful in this refinancing. In the event we are unable to refinance our revolving credit facility by June 30, 2005, we would be obligated to repay any outstanding amounts, and make alternative arrangements for the letters of credit issued pursuant to this credit facility. As of September 30, 2004, we had no borrowings outstanding and had approximately $1.1 billion of letters of credit issued under this credit facility.

Although we expect to successfully refinance all or a portion of our existing revolving credit facility, if we were unsuccessful, we believe we could adjust our planned capital expenditures and increase our planned asset sales to meet any shortfall in liquidity, and at the same time provide for our operations. Further, if we repaid our obligations under the revolving credit facility, some of the assets that currently collateralize this facility, including our equity interests in TGP, EPNG, ANR, CIG, WIC, Southern Gas Storage Company, ANR Storage Company and our common units in Enterprise, could be used to support new financing transactions. Although we cannot guarantee the outcome of future events, we believe that this available collateral would be adequate to provide financing sufficient to meet our liquidity needs.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived its financial filing requirements through December 31, 2004. The filing of our second quarter 2004 Form 10-Q and the first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the events of non-compliance resulting from the failure to file financial statements. In addition, neither we nor any of our subsidiaries have received a notice of the default caused by our failure to file financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

Furthermore, the material restatement of our financial statements for the period ended December 31, 2001 as was reported in our 2003 Annual Report on Form 10-K could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004. Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

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 to do so under their financing agreements and indentures. Under the cash management program, depending on whether participating subsidiaries have short-term cash requirements or surpluses, we either provide cash to them or they provide cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to us via our cash management program due to its anticipated cash needs. In addition, our ownership in a number of our subsidiaries and investments serve as collateral under our revolving credit facility and our other financings. If the lenders under the credit facility or those other financings were to exercise their rights to this collateral, we could lose our ownership interest in these subsidiaries or be required to liquidate these investments.

If, as a result of the events described above, we were subject to voluntary or involuntary bankruptcy proceedings, our creditors could attempt to make claims against our subsidiaries, including claims to substantively consolidate those subsidiaries. We believe that claims to substantively consolidate our subsidiaries would be without merit. However, there is no assurance that our creditors would not advance such a claim in a bankruptcy proceeding. If our creditors were able to substantively consolidate our subsidiaries, it could have a material adverse effect on our financial condition and our liquidity.

Despite the events and factors described above, we believe we will be able to meet our ongoing liquidity and cash needs through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our revolving credit facility, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, and common or preferred equity securities. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans.

Capital Structure

Our 2003 Annual Report on Form 10-K 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, the information disclosed in that Form 10-K.

During the first quarter of 2004, we continued to reduce our debt as part of our Long-Range Plan announced in December 2003. Our activity during the quarter ended March 31, 2004 is as follows (in millions):

Short-term financing obligations, including current maturities	$ 1,457
Long-term financing obligations	20,275
Securities of subsidiaries	447
Total debt and securities of subsidiaries as of December 31, 2003	22,179
Principal amounts borrowed	50
Repayments/retirements of principal[(1)]	(576)
Sale of entity[(2)]	(72)
Redemptions and eliminations of securities of subsidiaries	(13)
Other	19
Total debt and securities of subsidiaries as of March 31, 2004	$21,587

(1) Amount includes $250 million repayments under our revolving credit facility and excludes $370 million repayments of long-term debt related to our Aruba refinery classified as part of our discontinued operations prior to the sale of this facility in early 2004.

(2) Amount relates to the sale of Mohawk River Funding IV.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Item 1, Financial Statements, Note 12.

Capital Resources and Liquidity

Overview of Cash Flow Activities for the Quarters Ended March 31, 2004 and 2003

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

	2004	2003
	(In millions)	
Cash flows from continuing operating activities		
Net loss before discontinued operations	$(151)	$(209)
Non-cash income adjustments	585	594
Changes in assets and liabilities	25	(251)
Cash flows from continuing operating activities	459	134
Cash flows from continuing investing activities	(136)	(839)
Cash flows from continuing financing activities	66	896
Discontinued operations		
Cash flows from operating activities	170	(223)
Cash flows from investing activities	753	362
Cash flows from financing activities	(923)	(139)
Change in cash and cash equivalents related to discontinued operations	—	—
Change in cash and cash equivalents	$ 389	$ 191

During the first quarter of 2004, we generated cash from several sources, including our principal continuing operations as well as through asset sales in both our continuing and discontinued operations. We used a major portion of that cash to fund our capital expenditures and to make payments to retire long-term debt. Overall, our cash sources and uses are summarized as follows (in billions):

Cash inflows	
Cash flows from continuing operations	$0.5
Net proceeds from the sale of assets and investments	0.4
Net discontinued operations activity[1]	0.6
Total cash inflows	1.5
Cash outflows	
Additions to property, plant and equipment	0.4
Payments to retire long-term debt[1]	0.6
Net payments of restricted cash	0.1
Total cash outflows	1.1
Net increase in cash	$0.4

[1] Excludes payments of approximately $370 million related to long-term debt at our Aruba refinery classified as part of discontinued operations.

As of September 30, 2004, we had available cash on hand and borrowing capacity under our revolving credit facility totaling $3.3 billion. A more detailed analysis of our cash flows from operating, investing and financing activities of our continuing operations and cash flow from discontinued operations is as follows.

Cash From Continuing Operating Activities

Overall, cash generated from our continuing operating activities was $0.5 billion during the first quarter of 2004 versus $0.1 billion during the same period of 2003. The $0.4 billion quarter over quarter increase in operating cash flow was due primarily to the significant amount of working capital used in 2003 to meet collateral and margin call requirements relative to 2004. During 2003, increases in natural gas prices and our credit rating downgrades caused us to use approximately $0.4 billion of operating cash flow to fund margin calls.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $0.1 billion for the quarter ended March 31, 2004. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$ 0.3
Pipeline expansion, maintenance and integrity projects	0.1
Restricted cash activity	0.1
Proceeds from the sale of assets and investments	(0.4)
Total continuing investing activity	$ 0.1

Cash received from the sale of assets and investments was primarily from the sale of natural gas and oil properties. For the remainder of 2004, we expect our total capital expenditures to be approximately $1.7 billion, which includes approximately $0.6 billion for our Production segment and $1.0 billion for our Pipelines segment.

Cash From Continuing Financing Activities

Net cash provided by our continuing financing activities was $0.1 billion for the quarter ended March 31, 2004. Cash provided from our financing activities included $0.6 billion of cash contributed by our discontinued operations and other financing activities of $0.1 billion. Cash used in our financing activities included net repayments of $0.6 billion made to retire third party long-term debt.

Cash from Discontinued Operations

During the first quarter of 2004, our discontinued operations generated $0.6 billion of cash. We generated $0.2 billion in cash in these operations and received proceeds from asset sales of $0.8 billion, offset by payments of long-term debt of $0.4 billion.

Commodity-based Derivative Contracts

We utilize 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 and valuation methodology as of March 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	$ 26	$ 49	$ —	$ —	$ —	$ 75
Liabilities	(31)	(57)	(12)	(10)	—	(110)
Total derivatives designated as hedges	(5)	(8)	(12)	(10)	—	(35)
Assets from power contract restructuring derivatives[1][2]	208	428	376	681	130	1,823
Other commodity-based derivatives						
Exchange-traded positions[3]						
Assets	78	27	56	(2)	—	159
Liabilities	(71)	(16)	3	—	—	(84)
Non-exchange-traded positions						
Assets	408	275	141	202	61	1,087
Liabilities[1]	(679)	(502)	(203)	(246)	(57)	(1,687)
Total other commodity-based derivatives	(264)	(216)	(3)	(46)	4	(525)
Total commodity-based derivatives	$ (61)	$ 204	$ 361	$ 625	$134	$ 1,263

(1) Includes $242 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 quarter ended March 31, 2004.

(2) Includes $864 million of assets from derivative contracts that we sold in the second quarter of 2004. See Item 1, Financial Statements, Note 6, for a discussion of the impairment related to this sale.

(3) Exchange-traded positions are 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, 2004 to March 31, 2004:

	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 January 1, 2004	$(31)	$1,925	$(488)	$1,406
Fair value of contract settlements during the period	17	(121)	98	(6)
Change in fair value of contracts	(21)	19	(133)	(135)
Option premiums received, net	—	—	(2)	(2)
Net change in contracts outstanding during the period	(4)	(102)	(37)	(143)
Fair value of contracts outstanding at March 31, 2004	$(35)	$1,823	$(525)	$1,263

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.

During the first quarter of 2004, we sold a restructured power contract with a fair value of $75 million in conjunction with the sale of our interest in Mohawk River Funding IV. During the second quarter of 2004, we sold a restructured power contract with a fair value of $864 million in conjunction with the sale of our interest in Utility Contract Funding. See Item I, Financial Statements, Notes 4 and 6, for additional information on these sales.

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 or, if not settled, until the end of the period.

Segment Results

Below are our results of operations (as measured by EBIT) by segment. During 2004, we reorganized our business structure into two primary business lines, regulated and unregulated, 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 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 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 2004. The 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 our continuing corporate operations. Our operating results for all periods presented reflect this change.

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 consolidated EBIT to our consolidated net loss for the quarters ended March 31:

	2004	2003
	(In millions)	
Regulated Businesses		
Pipelines	$ 386	$ 429
Unregulated Businesses		
Production	95	449
Marketing and Trading	(172)	(434)
Power	(139)	(196)
Field Services	36	27
Segment EBIT	206	275
Corporate	27	(147)
Consolidated EBIT from continuing operations	233	128
Interest and debt expense	(422)	(413)
Distributions on preferred interests of consolidated subsidiaries	(6)	(21)
Income taxes	44	106
Loss from continuing operations	(151)	(200)
Discontinued operations, net of income taxes	(55)	(222)
Cumulative effect of accounting changes, net of income taxes	—	(9)
Net loss	$(206)	$(431)

Overview of Results of Operations

In the first quarter of 2004, our consolidated EBIT from continuing operations was $233 million of which $206 million was our segment EBIT. During the quarter, our Pipelines, Production and Field Services segments contributed $517 million of combined EBIT. These positive contributions were partially offset by EBIT losses of $311 million in our Power and Marketing and Trading segments. The following overview summarizes the results of operations of our operating segments.

Pipelines	The Pipelines segment generated EBIT of $386 million, which was generally consistent with our expectations for the period.
Production	The Production segment generated EBIT of $95 million, which was below our expectations for the period, primarily due to ceiling test and other charges of $130 million. These charges were primarily associated with our Canadian operations, the majority of which were sold during the period. Our production volumes were also below expectations for the period and our production costs were higher. However, offsetting these impacts were higher than expected commodity prices and lower than expected depreciation costs due to the impact of the reserve and hedge restatements in periods prior to 2004.
Marketing and Trading	The Marketing and Trading segment generated an EBIT loss of $172 million, which was significantly below our expectations. The performance was driven primarily by mark-to-market losses in our natural gas portfolio as natural gas prices increased in the period, partially offset by mark-to-market income in our major tolling contract. Our natural gas portfolio exposure was impacted by the hedge restatement in periods prior to 2004, resulting in a mark-to-market position that will result in losses as natural gas prices increase.
Power	The Power segment generated an EBIT loss of $139 million, which was below our expectations for the period, primarily due to asset impairments of $246 million. These impairments were primarily related to two of our plants in Brazil due to events in the first quarter of 2004 that may make it difficult to extend their power sales agreements that expire in 2005 and 2006, and due to certain of our domestic operations which are being sold.
Field Services	The Field Services segment generated EBIT of $36 million, which was consistent with our expectations for the period and impacted by the significant asset sales activity in the segment in 2003.

For the remainder of 2004, we expect the trends discussed above to continue, given the historic stability in our pipeline business and the current favorable pricing environment for natural gas. We expect our EBIT to decline in our Field Services segment in the fourth quarter of 2004 as a result of the completion of sales of our interests in GulfTerra and a majority of our remaining processing assets. In our Power segment, we expect to generate additional EBIT losses as a result of liquidating our power contract restructuring derivatives and as we continue to sell our domestic power plant portfolio. Internationally, we continue to foresee challenges in our operating areas, particularly in Brazil where we have significant power investments. Finally, we anticipate our Marketing and Trading segment's EBIT will continue to be volatile due to unpredictable changes in natural gas and power prices as they relate to our historical trading portfolio as we transition toward a core marketing business.

Our earnings in each period were impacted both favorably and unfavorably by a number of factors affecting our businesses that are enumerated in the table below. The discussion that follows summarizes these factors and their impact on our operating segments and our corporate activities. For a more detailed discussion of these factors and other items impacting our financial performance for the quarters ended March 31, see the individual segment and other results included in Item 1, Financial Statements, Notes 5, 6, 7 and 17.

	Operating Segments					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate
	(In millions)					
2004						
Asset and investment impairments, net of gain (loss) on sale	$ 1	$ (93)	$—	$(242)	$(3)	$ 3
Ceiling test charges	—	(28)	—	—	—	—
Restructuring charges	(4)	(9)	(2)	(3)	(1)	(8)
Total	$(3)	$(130)	$(2)	(245)	$(4)	$ (5)
2003						
Asset and investment impairments, net of gain (loss) on sale	$—	$ (9)	$ 1	$(288)	$—	$(29)
Ceiling test charges	—	(1)	—	—	—	—
Restructuring charges	—	(3)	(1)	(3)	—	(62)
Total	$—	$ (13)	$—	$(291)	$—	$(91)

The following is a discussion of the year over year results of each of our business segments as well as our corporate activities, interest and debt expense, distributions on preferred interests of consolidated subsidiaries, income taxes and the results of our discontinued petroleum markets and coal operations.

Regulated Businesses — Pipelines Segment

Our Pipelines segment owns and operates our interstate natural gas transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our 2003 Annual Report on Form 10-K. Below are the operating results and analysis of these results for our Pipelines segment for the quarters ended March 31:

Pipelines Segment Results	2004	2003
	(In millions, except volume amounts)	
Operating revenues	$ 721	$ 753
Operating expenses	(373)	(369)
Operating income	348	384
Other income	38	45
EBIT	$ 386	$ 429
Throughput volumes (BBtu/d)[1]	22,771	23,858

[1] Throughput volumes for the quarter ended March 31, 2003 exclude volumes related to our equity investment in Portland Natural Gas Transmission System which was sold in the fourth quarter of 2003, and exclude intrasegment activities. Throughput volumes includes volumes related to our Mexico investments which were transferred from our Power segment effective January 1, 2004.

Operating Results (EBIT)

The following factors contributed to our overall EBIT decrease of $43 million for the quarter ended March 31, 2004 as compared to the quarter ended March 31, 2003:

	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
ANR				
Contract remarketing/restructuring with We Energies and other customers	$(20)	$—	$—	$(20)
Termination of Dakota gasification facility contract	(16)	15	—	(1)
Southern Natural Gas Company (SNG)				
Equity earnings from Citrus — gas sales activities	—	—	(9)	(9)
Mainline expansions	10	(2)	(2)	6
EPNG				
Impact of lower power purchase costs and higher natural gas prices on natural gas imbalances	—	(7)	—	(7)
Termination of customer risk sharing mechanism in December 2003	(6)	—	—	(6)
Impact of capacity obligation to former full requirements customers	(3)	—	—	(3)
CIG				
Storage facility gas loss replacement in 2004	—	(6)	—	(6)
Impact of the finalization of a rate case settlement in 2003	(4)	—	—	(4)
Other				
Favorable resolution of a measurement dispute at a processing plant serving our TGP system	10	—	—	10
Other	(3)	(4)	4	(3)
Total	$(32)	$(4)	$(7)	$(43)

The renegotiation or restructuring of several contracts on our pipeline systems will continue to unfavorably impact our operating results and EBIT for the remainder of 2004, among other items noted below. Guardian Pipeline, which is owned in part by We Energies, is currently providing a portion of its firm transportation requirements and directly competes with ANR for a portion of the markets in Wisconsin. Additionally, ANR will continue to experience lower operating revenues and lower operating expenses for the remainder of 2004 based on the termination of the Dakota contract on its system. However, the termination of this contract will not have a significant overall impact on operating income and EBIT.

The impact of the termination of EPNG's risk sharing mechanism in December 2003 will continue to reduce its comparative EBIT for the remainder of 2004. However, with the completion of Phases I and II of EPNG's Line 2000 Power-up project in February and April of 2004, EPNG is now able to re-market the 110 MMcf/d capacity obligation for former full requirements customers. EPNG is at risk for the permanently released portion of such capacity and it must demonstrate that sales of the capacity do not adversely impact its service to firm customers.

Our operating results in future periods will also be impacted by other factors in addition to those noted above. ANR has entered into an agreement with a shipper to restructure another of its transportation contracts on its Southeast Leg as well as a related gathering contract. We anticipate this restructuring will be completed in March 2005 upon which ANR will receive $26 million.

Unregulated Businesses — Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are impacted 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 and sell the products at attractive prices.

Operational Update

Our long-term strategy includes developing our production opportunities primarily in the U.S. and Brazil, while prudently divesting of our production properties outside of these areas. In the second quarter of 2004, our Board of Directors approved exiting our Canadian and other international natural gas and oil operations. We will report these operations as discontinued operations beginning in the second quarter of 2004. As of September 2004, we have sold all of our Canadian operations and substantially all of our operations in Indonesia. Our operations in Canada included activities in Nova Scotia where, in the first quarter of 2004, we drilled an exploratory well that was not commercially viable and therefore recorded a $24 million ceiling test charge. In July 2004, we acquired the remaining 50 percent interest in UnoPaso, which increased our operations in Brazil.

Through September 2004, we have spent $616 million in capital expenditures for acquisition, exploration, and development activities. Based on the finding and development costs experienced in our 2004 drilling program, we expect our domestic unit of production depletion rate to increase from $1.58 per Mcfe during the first quarter 2004 to $1.64 Mcfe for the second quarter of 2004 and to $1.74 per Mcfe for the third quarter of 2004.

For the first quarter of 2004, our total equivalent production declined approximately 37 Bcfe or 30 percent compared to the same period in 2003. This decline was caused by asset sales in 2003 primarily in Oklahoma and New Mexico, normal production declines and disappointing drilling results. For the first nine months of 2004, our production averaged approximately 845 MMcfe/d; however, for the month of September 2004 daily production averaged approximately 765 MMcfe/d. At the end of the first quarter of 2004, we sold our production operations in western Canada which had an average daily production of approximately 50 MMcfe/d. As mentioned above, in July 2004, we acquired the remaining 50 percent interest in our UnoPaso investment in Brazil. Prior to this acquisition, we treated our interest in UnoPaso as an equity method investment and, therefore, did not include our proportionate share of its production in our average daily production amounts. Subsequent to the acquisition of the remaining interest, we began consolidating the operations of UnoPaso, which is producing an average of approximately 55 MMcfe/d. Our production levels are dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future asset sales or acquisitions.

Earlier this year, we completed a restatement of our historical financial statements to reflect significant revisions of our proved natural gas and oil reserves and to revise our accounting treatment for the majority of our production hedges. The impact of these restatements on our Production segment in 2004 include lower depreciation expense due to the higher ceiling test charges in the restated periods and higher realized prices due to the restatement of the hedges, which were all at hedged prices below market prices in 2004.

Production Hedging

We primarily conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on our sales. 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 a further discussion of our hedging program and additional hedges put in place in May and August 2004, refer to our 2003 Annual Report on Form 10-K.

In October 2004, we entered into additional transactions in our Marketing and Trading segment designed to provide protection to El Paso from natural gas price declines in 2005. These "put" contracts will not be treated as hedges for accounting purposes, but will provide El Paso with a floor price of $6.00 per MMBtu on 54 TBtu of our natural gas production in 2005.

Further, we are reviewing a separate strategy under which we would designate certain of the natural gas derivatives that are currently marked to market in our Marketing and Trading segment as hedges of our natural gas production. Transactions of this type would be treated as hedges for accounting purposes and would generally have the effect of hedging a portion of our natural gas production volumes at current market prices, while reducing the earnings exposure in our Marketing and Trading segment to future natural gas price changes. These derivative hedge designations would have no impact on the company's overall cash flow in any period, but would impact the timing of recognizing the changes in the fair value of these derivatives in El Paso's overall operating results.

Operating Results

Below are the operating results and analysis for our Production segment for the quarters ended March 31:

Production Segment Results	**2004**	**2003**
	(In millions, except volumes and prices)	
Operating revenues:		
Natural gas	$ 393	$ 653
Oil, condensate and liquids	79	105
Other	2	2
Total operating revenues	474	760
Transportation and net product costs	(17)	(31)
Total operating margin	457	729
Operating expenses:		
Depreciation, depletion and amortization	(149)	(164)
Production costs[1]	(45)	(64)
Ceiling test and other charges[2]	(130)	(13)
General and administrative expenses	(37)	(44)
Taxes, other than production and income taxes	(2)	(4)
Total operating expenses[3]	(363)	(289)
Operating income	94	440
Other income	1	9
EBIT	$ 95	$ 449
Volumes, prices and costs per unit:		
Natural gas		
Volumes (MMcf)	70,393	101,743
Average realized prices including hedges ($/Mcf)[4]	$ 5.59	$ 6.42
Average realized prices excluding hedges ($/Mcf)[4]	$ 5.66	$ 6.68
Average transportation costs ($/Mcf)	$ 0.19	$ 0.22
Oil, condensate and liquids		
Volumes (MBbls)	2,768	3,724
Average realized prices including hedges ($/Bbl)[4]	$ 28.62	$ 28.31
Average realized prices excluding hedges ($/Bbl)[4]	$ 28.62	$ 29.10
Average transportation costs ($/Bbl)	$ 1.19	$ 0.98

Production Segment Results	2004	2003
	(In millions, except volumes and prices)	
Production cost ($/Mcfe)		
Average lease operating costs	$ 0.49	$ 0.35
Average production taxes	0.03	0.17
Total production cost	$ 0.52	$ 0.52
Average general and administrative expense ($/Mcfe)	$ 0.42	$ 0.36
Unit of production depletion cost ($/Mcfe)	$ 1.58	$ 1.24

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

(2) Includes ceiling test charges, restructuring costs, asset impairments and loss on long-lived assets.

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

(4) Prices are stated before transportation costs.

Quarter Ended March 31, 2004 Compared to Quarter Ended March 31, 2003

For the quarter ended March 31, 2004, EBIT was $354 million lower than the same period in 2003. The decrease is due to lower realized natural gas prices and lower production volumes as a result of asset sales, normal production declines and disappointing drilling results. Also contributing to lower EBIT were higher operating expenses due to higher ceiling test and other charges in 2004.

Operating Revenues. The following table describes the variance in revenue between the quarters ended March 31, 2004 and 2003 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges on our revenues.

	Variance			
Production Revenue Variance Analysis	Prices	Volumes	Hedges	Total
	(In millions)			
Natural gas	$ (72)	$(209)	$21	$(260)
Oil, condensate and liquids	(1)	(28)	3	(26)
Total operating revenues	$ (73)	$(237)	$24	$(286)

For the quarter ended March 31, 2004, operating revenues were $286 million lower than the same period in 2003 due to lower market prices for natural gas and oil and lower production volumes, partially offset by a decrease in losses from our hedging program. The decline in natural gas volumes was primarily due to the sale of properties in 2003 in New Mexico, Oklahoma, offshore Gulf of Mexico and western Canada as well as normal production declines and disappointing drilling results.

Average realized natural gas prices for the first quarter of 2004, excluding hedges, were $1.02 per Mcf lower than the same period in 2003, a decrease of 15 percent. However, partially offsetting the decrease in revenues were $5 million of hedging losses in 2004 as compared to $26 million of hedging losses in 2003 relating to our natural gas hedge positions. We expect to continue to incur hedging losses in 2004 based on current market prices for natural gas relative to the prices at which our natural gas production is hedged.

Operating Expenses. Total operating expenses were $74 million higher for the first quarter of 2004 as compared to the first quarter of 2003 primarily due to higher ceiling test and other charges, partially offset by lower depreciation, depletion, and amortization expense, lower production costs, and lower general and administrative expenses.

Ceiling test and other charges increased by $117 million in 2004. During 2004, we incurred an $85 million loss associated with the sale of our Canadian operations, a $24 million impairment related to an exploratory well drilled in Nova Scotia that was not commercially viable and an $8 million impairment related to a non-full cost pool asset in Canada.

Total depreciation, depletion, and amortization expense decreased by $15 million in the first quarter of 2004 as compared to the same period in 2003. Lower production volumes in 2004 due to the asset sales and other production declines discussed above resulted in a decrease of $46 million. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs and a lower reserve base, which contributed an increase of $29 million in our depreciation, depletion, and amortization expense.

Production costs decreased by $19 million in the first quarter of 2004 as compared to the same period in 2003 due to a decrease in production taxes resulting from high cost gas well tax credits in the first quarter of 2004 and due to lower commodity prices in 2004 compared to 2003. Production taxes decreased $0.14 per Mcfe in 2004. However, our total production costs per Mcfe remained the same between the first quarter of 2004 and 2003 as average lease operating costs increased $0.14 per Mcfe in 2004 primarily due to lower production volumes discussed above.

General and administrative expenses decreased by $7 million, but increased $0.06 per Mcfe, in the first quarter of 2004 as compared to the same period in 2003. The total dollar decrease was primarily due to lower corporate overhead allocations as we reduced corporate expenses, while the increase on a per unit basis was due to lower production volumes.

Unregulated Business — Marketing and Trading Segment

Earlier this year, we completed a restatement of our historical financial statements to reflect significant revisions of our proved natural gas and oil reserves and to revise our accounting treatment for the majority of our production hedges. This restatement impacted our 2004 operating results by changing the accounting for many of our natural gas hedging contracts. This change will result in increased earnings volatility in the future related to these derivative contracts as natural gas prices change. For a further discussion of the restatement, refer to our 2003 Annual Report on Form 10-K.

As discussed in our Production segment, in October 2004, we entered into additional transactions designed to provide protection to El Paso from natural gas price declines in 2005. These "put" contracts will provide El Paso with a floor price of $6.00 per MMBtu on 54 TBtu of our Production segment's natural gas production in 2005. Under these contracts, we will generally have mark-to-market earnings if the current and future price of natural gas declines in any given period and losses if the current and future price of natural gas increases in any given period.

Further, we are reviewing a strategy under which certain of our fixed price natural gas derivatives that are currently marked to market would be designated as hedges of the natural gas production in our Production segment. Transactions of this type would generally be treated as hedges for accounting purposes and would have the effect of hedging a portion of the natural gas production volumes in our Production segment at current market prices while reducing our earnings exposure to future natural gas price changes. These derivative hedge designations would have no impact on El Paso's overall cash flow in any period, but would impact the timing of recognizing the changes in the fair value of these derivatives in El Paso's overall operating results.

Our operations primarily consist of the management of our trading portfolio and the marketing of our Production segment's natural gas and oil production. Below are our segment operating results and an analysis of these results for the quarters ended March 31:

Marketing and Trading Segment Results

	2004	2003
	(In millions)	
Gross margin[1]	$(159)	$(390)
Operating expenses	(16)	(51)
Operating loss	(175)	(441)
Other income	3	7
EBIT	$(172)	$(434)

(1) Gross margin 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.

For the quarter ended March 31, 2004, our gross margin improved by $231 million compared to the same period in 2003. This improvement was due primarily to a $314 million decrease in the fair value of our derivatives, principally our natural gas contracts, during 2003 compared to a $148 million decrease in the fair value of our trading positions during 2004. We sell natural gas at a fixed price in many of our trading contracts. The increase in natural gas futures prices in the first quarter of 2003 was more significant than the increase in the first quarter of 2004, resulting in a decrease in the fair value of these derivatives in the first quarter of 2003 that was greater than the same period in 2004. Also contributing to this improvement was $34 million of losses related to the early termination of some of our derivative and non-derivative contracts in 2003, compared to less than $1 million in 2004. Our non-derivative contracts also had settlement losses of $33 million in 2004 compared to $48 million in 2003, which primarily related to demand charges we could not recover on existing transportation contracts. In 2003, we were actively liquidating the derivative and non-derivative positions in our trading portfolio. In 2004, we refocused our efforts on managing the existing positions in our portfolio and, as a result, began to experience the benefits of previous contract terminations through lower demand charges. These improvements were partially offset by a $15 million increase in the fair value of our Midwest derivative tolling agreement in 2004 compared to a $38 million increase in 2003. This tolling contract is sensitive to changes in forecasted power prices relative to forecasted natural gas prices in the Midwest. We expect the fair value of this contract to be volatile over its entire contract term, which extends through 2019.

For the quarter ended March 31, 2004, our operating expenses decreased by $35 million compared to the same period in 2003. This decrease was primarily due to $11 million of amortization expense on a Western Energy Settlement obligation that was transferred to our corporate operations in late 2003. Also contributing to the decrease was a $10 million decrease in corporate overhead allocations and an $8 million decrease in operating expenses of our London office, which was closed in 2003.

Unregulated Businesses — Power Segment

Our Power segment has three primary business activities: domestic power plant operations, domestic power contract restructuring activities and international power plant operations. Below are our segment operating results, a summary of the operating results of each of its activities and an analysis of those results for the quarters ended March 31:

Power Segment Results	2004	2003
	(In millions)	
Gross margin[1]	$ 160	$ 179
Operating expenses	(348)	(184)
Operating loss	(188)	(5)
Other income (expense)	49	(191)
EBIT	$(139)	$(196)
Domestic Power		
Domestic power plant operations	1	(261)
Domestic power contract restructuring business	(74)	28
International Power		
Brazilian power operations	(78)	22
Other international power operations	23	28
Other	(11)	(13)
EBIT	$(139)	$(196)

(1) Gross margin 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.

Domestic Power Plant Operations

Our domestic power plant operations relate to the ownership and operation of power plant assets in the U.S. For the quarter ended March 31, 2004, the EBIT generated by our domestic power plant operations was $262 million higher than the same period in 2003. This increase was primarily due to a decrease in the amount of impairments in 2004 compared to 2003. In 2003, we recognized a $207 million impairment on our investment in Chaparral and an $86 million loss due to the write-off of receivables as a result of the transfer of our interest in the Milford power facility to the plant's lenders. In 2004, we recognized impairments of $11 million on our domestic power plants included as assets held for sale to adjust the carrying value of these plants to the expected sales price. Offsetting this net increase was a decrease in operating income in 2004 of $19 million from our East Coast Power facility which was sold during 2003. The majority of our domestic plants were sold in the second and third quarters of 2004.

Domestic Power Contract Restructuring Business

Our domestic power contract restructuring business relates to the continued performance under our previously restructured power contracts. For the quarter ended March 31, 2004, the EBIT generated by our domestic power contract restructuring business was $102 million lower than the same period in 2003. This decrease was due primarily to the announced sale of Utility Contract Funding and its restructured power contract and related debt, which resulted in a $98 million impairment loss during the first quarter of 2004. In August, 2004, our Board of Directors approved the sale of wholly owned subsidiaries Cedar Brakes I and II which own restricted power contracts that are recorded at market value. Should we sell these entities for less than their market value, we will record a loss in the period the sale is final. Also contributing to EBIT for the quarters ended March 31, 2004 and 2003 were increases of $19 million and $20 million in the fair value of our restructured power contracts.

International Power Plant Operations

Brazil. During the first quarter of 2003, we conducted a majority of our power plant operations in Brazil through Gemstone, an unconsolidated joint venture. In the second quarter of 2003, we acquired the joint venture partner's interest in Gemstone and began consolidating Gemstone's debt and its investments in the Macae, Porto Velho and Araucaria power plants. As a result, our first quarter 2004 consolidated operating results include the revenues, expenses and equity earnings from Gemstone's assets. Our first quarter 2003 operating results include the equity earnings we earned from Gemstone.

For the quarter ended March 31, 2004, the EBIT loss generated by our Brazilian power plant operations was $78 million compared to EBIT of $22 million in the same period in 2003. Our 2004 EBIT loss was primarily due to $135 million of impairments of the Manaus and Rio Negro power plants due to events in the first quarter of 2004 that may make it difficult to extend their power sales agreements that expire in 2005 and 2006. These losses were partially offset by $42 million of operating income from our Macae power plant and $7 million from our Porto Velho power plant in 2004. Our 2003 EBIT was primarily due to $17 million of equity earnings from Gemstone, which primarily included the operating results from the Macae, Porto Velho and Araucaria power plants above and the cost of the debt held by Gemstone.

Other International. For the quarter ended March 31, 2004, the EBIT generated by our other international power operations was $5 million lower than the same period in 2003. The decrease was primarily due to a decrease in EBIT from our Central American and European power plants, which primarily resulted from increased fuel and maintenance expenses.

Other Power Operations

Our other power operations consist of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance and engineering costs, and the costs of carrying our power turbine inventory. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations. In the first quarter 2004, our general and administrative expenses remained relatively consistent with the same period in 2003.

We are currently in the process of selling a number of our domestic and international power assets. As these sales occur and as sales agreements are negotiated and approved, it is possible that impairments of these assets may occur, and these impairments may be material.

Unregulated Businesses — Field Services Segment

Our Field Services segment conducts our midstream activities which include gathering and processing of natural gas. Until September 2004, our assets principally consisted of our general and limited partner holdings of GulfTerra, a publicly traded master limited partnership in which our subsidiary served as the general partner, and consolidated processing assets in south Texas and south Louisiana. In September 2004, we sold substantially all of our remaining interests in GulfTerra as well as our south Texas processing plants to Enterprise as part of the merger transaction between GulfTerra and Enterprise. Following these sales, substantially all of our gathering and processing business will be conducted through our remaining ownership interests in the merged partnership. For a discussion of our ownership interests in GulfTerra and our activities with the partnership, see Item 1, Financial Statements, Note 17.

Investment in GulfTerra

We recognize earnings and receive cash from GulfTerra in several ways, including through a share of the partnership's cash distributions and through our ownership of limited, preferred and general partner interests. During 2003, the primary source of earnings in our Field Services segment was from our equity investment in GulfTerra. Our sale of an effective 50 percent interest in GulfTerra's general partner in December 2003 as well as the completion of the sale in September 2004 of our remaining interest in the general partner of GulfTerra (upon which we received cash and a 9.9 percent interest in the general partner of Enterprise Products GP, LLC) has and will continue to result in lower equity earnings in 2004. In addition, we have agreed to provide a total of $45 million in payments during the three years after the merger becomes effective. Prior to completion of the sale of substantially all of our interests in GulfTerra to Enterprise, we received management fees under an agreement to provide operational and administrative services to the partnership. These management fees increased as a result of GulfTerra's asset acquisitions in 2002 and 2003. Upon the closing of the merger of GulfTerra and Enterprise, these fees and many of the internal costs of providing these management services were eliminated. We are reimbursed for costs paid directly by us on the partnership's behalf. For the quarters ended March 31, 2004 and 2003, we were reimbursed approximately $22 million and $24 million for expenses incurred on behalf of the partnership. During 2004, our earnings and cash distributions received from GulfTerra were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner's share of distributions	$ 21	$ 21
Proportionate share of income available to common unit holders	5	7
Series C units	5	8
Gains on issuance by GulfTerra of its common units	3	—
	$ 34	$ 36

For a further discussion of the business activities of our Field Services segment, see our 2003 Annual Report on Form 10-K. Below are the operating results and analysis of these results for our Field Services segment for the quarters ended March 31:

Field Services Segment Results	2004	2003
	(In millions)	
Processing and gathering gross margins[(1)]	$ 45	$ 47
Operating expenses	(35)	(47)
Operating income	10	—
Other income	26	27
EBIT	$ 36	$ 27
Volumes and Prices:		
Processing		
Volumes (inlet BBtu/d)	3,243	3,307
Prices ($/MMBtu)	$ 0.13	$ 0.11
Gathering		
Volumes (BBtu/d)	186	577
Prices ($/MMBtu)	$ 0.12	$ 0.22

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

For the quarter ended March 31, 2004, our EBIT was $9 million higher than the same period in 2003. The effect of lower natural gas prices in 2004 relative to liquid prices in our processing operations increased EBIT by $13 million; however the effect of sales of our gathering and processing assets reduced EBIT by $6 million.

Overall, margins decreased in the first quarter of 2004 by $2 million as compared to the same period in 2003 due primarily to a reduction of $14 million from asset sales in 2003, partially offset by a $13 million increase at our remaining processing facilities. In these processing operations, while NGL prices remained relatively flat in 2004 compared to the same period in 2003, we experienced an increase in margin because of lower natural gas prices in 2004. These lower natural gas prices increased our margin per unit at our processing facilities in south Texas and increased the amount of NGLs extracted compared to 2003.

Operating expenses for the quarter ended March 31, 2004 were $12 million lower than the same period in 2004 primarily as a result of asset sales. In August 2004, our Board of Directors authorized the sale of our Indian Springs natural gas gathering and processing assets in our Field Services segment. We currently expect to incur an impairment charge of approximately $13 million related to these assets.

Corporate, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, including financial services and LNG and related items, all of which are immaterial to our results in 2004. During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to our continuing corporate operations. Our operating results for all periods reflect this change.

For the quarter ended March 31, 2004, EBIT in our corporate operations was $174 million higher than the same period in 2003 due to the following:

	Increase in EBIT in 2004 compared to 2003
	(In millions)
Lower impairments and contract terminations in our LNG business	$ 65
Lower foreign currency losses on Euro-denominated debt	45
Lower losses on the Lakeside and Metro assets in our telecommunications business	16
Lower realized losses on sale of aircraft	14
Higher operating income on financial services investments	12
Lower employee severance, retention and transition costs	10
Higher revenues on petroleum ship charters due to increased demand	7
Other increases	5
Total increase in EBIT	$174

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. We are currently evaluating each of these suits as to their merits and our defenses, Settlements and/or adverse rulings against us related to these and other legal matters would impact our future results. Additionally, during 2004, we hedged an additional €100 million of our Euro-denominated debt, which we expect will continue to reduce our exposure to foreign currency fluctuations. As discussed in Item 1, Financial Statements, Note 5, we incurred relocation charges of approximately $30 million in the third quarter of 2004 related to the consolidation of our Houston-based operations. We estimate the total accrual for our liability will be approximately $80 million to $100 million.

Interest and Debt Expense

Interest and debt expense for the quarter ended March 31, 2004, was $9 million higher than the same period in 2003. Below is an analysis of our interest expense for the quarters ended March 31:

	2004	2003
	(In millions)	
Long-term debt, including current maturities	$397	$371
Revolving credit facilities	28	20
Other interest	8	28
Capitalized interest	(11)	(6)
Total interest and debt expense	$422	$413

Interest expense on long-term debt for the quarter ended March 31, 2004, was $26 million higher than the same period in 2003. The increase was due to higher average debt balances from the issuance and consolidation of debt during 2003 and the first quarter of 2004, net of retirements, resulting in increased interest of $28 million.

Interest expense on our revolving credit facility for the quarter ended March 31, 2004, was $8 million higher than the same period in 2003. This increase was due to $20 million in commitment fees on letters of credit outstanding and amortization of debt issue costs. Partially offsetting this increase was lower interest expense of $12 million due to lower average borrowings under these facilities in the first quarter of 2004 compared to 2003. Our average revolving credit balances, which were based on daily ending balances, were approximately $638 million, with an average interest rate of 4.65% during the first quarter of 2004.

Other interest for the quarter ended March 31, 2004, was $20 million lower than the same period in 2003. The decrease was primarily due to a $7 million decrease in 2004 as a result of the write-off of unamortized financing costs during 2003 due to the retirement of the Trinity River financing arrangement, a $6 million reduction in interest expense from the retirement of other financing obligations, $2 million due to lower interest paid on customer deposits and a $2 million reduction in affiliated interest expense on notes we had with Gemstone, which were eliminated as a result of the consolidation of these investments in the second quarter of 2003.

Capitalized interest for the quarter ended March 31, 2004, was $5 million higher than the same period in 2003 primarily due to higher average interest rates in 2004 than in 2003.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the quarter ended March 31, 2004 were $15 million lower than the same period in 2003 primarily due to the refinancing and redemption of our Clydesdale financing arrangement, the redemptions of the preferred stock on two of our subsidiaries, Trinity River and Coastal Securities, and the reclassification of our Coastal Finance I and Capital Trust I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150 in 2003. Based on this reclassification, we began recording the preferred returns on these securities as interest expense rather than as distributions of preferred interests. The decrease was also due to the impact of the consolidations of Chaparral and Gemstone as a result of our acquisitions of these investments. Our remaining balance of preferred interests as of March 31, 2004 primarily consists of $300 million of preferred stock of our consolidated subsidiary, El Paso Tennessee Pipeline Co.

Income Taxes

Income tax benefits from continuing operations and our effective tax rates for the quarters ended March 31 were as follows:

	2004	2003
	(In millions, except for rates)	
Income tax benefits	$(44)	$(106)
Effective tax rate	23%	35%

Our effective tax rates were different than the statutory tax rate of 35 percent primarily due to:

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates, including impairments of certain of our foreign investments;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- non-deductible dividends on the preferred stock of subsidiaries.

For the year ended December 31, 2004 we currently expect our effective tax rate to be significantly different from the statutory rate of 35 percent because of the closing of the GulfTerra transaction in September 2004. The sale of our interests in GulfTerra will result in a significant tax gain (versus a much lower book gain) and significant tax expense due to the non-deductibility of goodwill written off as a result of the transaction. We believe the impact of this non-deductible goodwill will increase our tax expense (or reduce our tax benefit) by approximately $139 million.

Proposed tax legislation has been introduced in the U.S. Senate which would disallow deductions for certain settlements made to or on behalf of governmental entities. 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 assets. Our total tax assets related to the Western Energy Settlement were $400 million as of March 31, 2004. In such event, our tax expense would increase.

For a further discussion of our effective tax rates, see Item 1, Financial Statements, Note 8.

Discontinued Operations

For the quarter ended March 31, 2004, our after-tax loss from our petroleum markets discontinued operations was $55 million. The loss was primarily due to losses of $40 million from the sale of our Eagle Point and Aruba refineries and $8 million of severance costs for work force reductions as assets are sold.

For the quarter ended March 31, 2003, our after-tax loss from petroleum markets discontinued operations was $225 million. The loss was primarily due to impairments of $350 million on our Eagle Point refinery and several of our chemical assets. The loss was partially offset by operating income from our Eagle Point and Aruba refineries of $79 million and gains of $55 million from the sale of our Corpus Christi refinery and the Florida terminalling and marine assets.

In the second quarter of 2004, our Board of Directors approved exiting our Canadian and other international natural gas and oil operations. We will report these operations as discontinued operations beginning in the second quarter of 2004.

Commitments and Contingencies

See Item 1, Financial Statements, Note 13, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- liquidity and cash flow;
- credit ratings;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic performance;
- operating income;
- management's plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our 2003 Annual Report on Form 10-K filed with the Securities and Exchange Commission on September 30, 2004.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our 2003 Annual Report on Form 10-K, 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 2003 Annual Report on Form 10-K, 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 $33 million as of March 31, 2004 and $34 million as of December 31, 2003, and represents our potential one-day unfavorable impact on the fair values of our trading contracts.

Interest Rate Risk

As of March 31, 2004, we had $1.6 billion of third party long-term power purchase and power supply derivative contracts. In the second quarter of 2004, we sold one of the contracts held by Utility Contract Funding, which had a fair value of $864 million as of March 31, 2004. The sale of this derivative and the planned sale of Cedar Brakes I and II, which hold two of our power derivative contracts, will substantially reduce our exposure to interest rate risk related to these contracts.

Item 4. Controls and Procedures

During 2003, we initiated a project to ensure compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX), which will apply to us at December 31, 2004. This project entailed a detailed review and documentation of the processes that impact the preparation of our financial statements, an assessment of the risks that could adversely affect the accurate and timely preparation of those financial statements, and the identification of the controls in place to mitigate the risks of untimely or inaccurate preparation of those financial statements. Following the documentation of these processes, which was substantially concluded by December 2003, we initiated an internal review or "walk-through" of these financial processes by the financial management responsible for those processes to evaluate the design effectiveness of the controls identified to mitigate the risk of material misstatements occurring in our financial statements. We also initiated a detailed process to evaluate the operating effectiveness of our controls over financial reporting. This process involves testing the controls for effectiveness, including a review and inspection of the documentary evidence supporting the operation of the controls on which we are placing reliance.

In September 2004, we completed investigations surrounding matters that gave rise to a restatement of our historical financial statements for the period from 1999 to 2002 and the first nine months of 2003. These investigations identified a number of internal control weaknesses which we reported as material control weaknesses in our Annual Report on Form 10-K.

The following are the internal control deficiencies identified as a result of our SOX implementation and from the independent reviews that led to the restatements of our historical financial statements, which we have previously disclosed:

- A weak control environment surrounding the booking of our natural gas and oil reserves in the Production segment;
- Inadequate controls over access to our proved natural gas and oil reserve system;
- Inadequate documentation of policies and procedures related to proved natural gas and oil reserves booking;
- Inadequate documentation of accounting conclusions in prior periods related to complex accounting standards;
- Lack of formal documentation and communication of policies and procedures with respect to accounting matters;
- Ineffective monitoring activities to ensure compliance with existing policies, procedures and accounting conclusions (in some cases as a result of inadequate staffing);
- Lack of formal evidence to substantiate monitoring activities were adequately performed (e.g. monitoring activities, such as meetings and report reviews, were not always documented in a way to objectively confirm the monitoring activities occurred);
- Inadequate change management and security access to our information systems (e.g., program developers were allowed to migrate system changes into production and passwords for some of our applications did not adhere to the corporate policy for effective passwords);
- Lack of proper segregation of duties related to manual journal entry preparation and procurement activities (e.g., our financial accounting system was not designed to prevent the same person from posting an entry that prepared the entry and a buyer of goods could also receive for the goods); and
- Untimely preparation and review of volume and accounting reconciliations.

We have communicated to our Audit Committee and to our external auditors the deficiencies identified to date in our internal controls over financial reporting as well as the remediation efforts that we have underway. Our management, with the oversight of our Audit Committee, is committed to effectively remediate known deficiencies as expeditiously as possible and continues its extensive efforts to comply with

Section 404 of SOX by December 31, 2004. Consequently, we have made the following changes to our internal controls:

- Added members to our Board of Directors, including our Audit Committee, and our executive management team with extensive experience in the natural gas and oil industry;
- Formed an internal committee to provide oversight of the proved natural gas and oil reserve estimation process, which is staffed with appropriate technical, financial reporting and legal expertise;
- Continued use of an independent third-party reserve engineering firm, selected by and reporting annually to the Audit Committee of the Board of Directors, to perform an independent assessment of our proved natural gas and oil reserves;
- Formed a centralized proved natural gas and oil reserve evaluation and reporting function, staffed primarily with newly hired personnel that have extensive industry experience, that is separate from the operating divisions and reports to the president of Production and Non-regulated Operations;
- Restricted security access to the proved natural gas and oil reserve system to the centralized reserve reporting staff;
- Revised our documentation of procedures and controls for estimating proved natural gas and oil reserves;
- Enhanced internal audit reviews to monitor booking of proved natural gas and oil reserves;
- Implemented standard information system policies and procedures to enforce change management and segregation of responsibilities when migrating programming changes to production and strengthened security policies and procedures around passwords for applications and databases;
- Modified systems and procedures to ensure appropriate segregation of responsibilities for manual journal entry preparation and procurement activities;
- Formalized our account reconciliation policy and timely completed all material account reconciliations; and
- Developed and implemented formal training to educate company personnel on management's responsibilities mandated by SOX Section 404, the components of the internal control framework on which we rely and the relationship to our company values including accountability, stewardship, integrity and excellence.

We are in the process of implementing the following changes to our internal controls and expect to have them implemented by December 31, 2004:

- Improved training regarding SEC guidelines for booking proved natural gas and oil reserves;
- Formal communication of procedures for documenting accounting conclusions involving interpretation of complex accounting standards, including identification of critical factors that support the basis for our conclusion;
- Evaluation, formalization and communication of required policies and procedures;
- Improved monitoring activities to ensure compliance with policies, procedures and accounting conclusions; and
- Review of the adequacy, proficiency and training of our finance and accounting staff.

Many of the deficiencies in our internal controls that we have identified are likely the result of significant changes the company has undergone during the past five years as a result of major acquisitions and reorganizations. As we continue our SOX Section 404 compliance efforts, including the testing of the effectiveness of our internal controls, we may identify additional deficiencies in our system of internal controls that either individually or in the aggregate may represent a material weakness requiring additional remediation efforts.

We did not make any changes to our internal controls over financial reporting during the quarter ended March 31, 2004, that have had a material adverse affect or are reasonably likely to have a material adverse affect on our internal controls over financial reporting. However, we have made significant changes to improve our internal controls during the quarter ended March 31, 2004, and subsequent to that date.

We also undertook a review of our overall disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As a result of the deficiencies described above, we concluded that our disclosure controls and procedures were not effective at March 31, 2004. However, to address the deficiencies in our internal controls, we expanded our disclosure controls and procedures to include additional analysis and other post-closing procedures to ensure our disclosure controls and procedures were effective over the preparation of these financial statements. Consequently, we concluded that our disclosure controls and procedures over the preparation of these financial statements were effective.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 13, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our Annual Report on Form 10-K filed with the Securities and Exchange Commission on September 30, 2004.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

None.

Item 6. Exhibits

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EL PASO CORPORATION

Date: October 27, 2004

/s/ D. Dwight Scott

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: October 27, 2004

/s/ Jeffrey I. Beason

Jeffrey I. Beason
Senior Vice President and Controller
(Principal Accounting Officer)