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 September 30, 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 December 16, 2004: 643,194,441

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 September 30,		Nine Months Ended September 30,	
	2004	2003 (Restated)	2004	2003 (Restated)
Operating revenues	$1,429	$1,714	$ 4,510	$ 5,111
Operating expenses				
Cost of products and services	390	362	1,215	1,415
Operation and maintenance	507	453	1,281	1,634
Depreciation, depletion and amortization	270	283	808	897
Loss on long-lived assets	550	54	789	463
Taxes, other than income taxes	67	81	197	229
	1,784	1,233	4,290	4,638
Operating income (loss)	(355)	481	220	473
Earnings from unconsolidated affiliates	617	79	815	31
Other income	36	49	139	132
Other expense	(21)	—	(57)	(129)
Interest and debt expense	(396)	(475)	(1,229)	(1,352)
Distributions on preferred interests of consolidated subsidiaries	(6)	(7)	(18)	(45)
Income (loss) before income taxes	(125)	127	(130)	(890)
Income taxes	77	62	124	(451)
Income (loss) from continuing operations	(202)	65	(254)	(439)
Discontinued operations, net of income taxes	(12)	(41)	(150)	(1,195)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(9)
Net income (loss)	$ (214)	$ 24	$ (404)	$(1,643)
Basic and diluted income (loss) per common share				
Income (loss) from continuing operations	$(0.31)	$ 0.11	$ (0.40)	$ (0.74)
Discontinued operations, net of income taxes	(0.02)	(0.07)	(0.23)	(2.00)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(0.02)
Net income (loss) per common share	$(0.33)	$ 0.04	$ (0.63)	$ (2.76)
Basic and diluted average common shares outstanding	639	596	639	596
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.12

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,329	$ 1,429
Accounts and notes receivable		
Customers, net of allowance of $196 in 2004 and $272 in 2003	1,280	2,039
Affiliates	123	189
Other	231	245
Inventory	154	181
Assets from price risk management activities	325	706
Assets held for sale and from discontinued operations	480	2,538
Restricted cash	234	590
Deferred income taxes	563	592
Other	258	413
Total current assets	5,977	8,922
Property, plant and equipment, at cost		
Pipelines	19,175	18,563
Natural gas and oil properties, at full cost	14,884	14,689
Power facilities	1,528	1,660
Gathering and processing systems	167	334
Other	890	998
	36,644	36,244
Less accumulated depreciation, depletion and amortization	18,019	18,049
Total property, plant and equipment, net	18,625	18,195
Other assets		
Investments in unconsolidated affiliates	3,052	3,551
Assets from price risk management activities	1,555	2,338
Goodwill and other intangible assets, net	424	1,082
Other	2,162	2,996
	7,193	9,967
Total assets	$31,795	$37,084

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 938	$ 1,552
Affiliates	13	26
Other	385	438
Short-term financing obligations, including current maturities	1,554	1,457
Liabilities from price risk management activities	599	734
Western Energy Settlement	44	633
Liabilities related to assets held for sale and discontinued operations	149	933
Accrued interest	359	391
Other	787	910
Total current liabilities	4,828	7,074
Long-term financing obligations	17,673	20,275
Other		
Liabilities from price risk management activities	1,046	781
Deferred income taxes	1,598	1,571
Western Energy Settlement	342	415
Other	1,910	2,047
	4,896	4,814
Commitments and contingencies		
Securities of subsidiaries	366	447
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 650,956,586 shares in 2004 and 639,299,156 shares in 2003	1,952	1,917
Additional paid-in capital	4,557	4,576
Accumulated deficit	(2,189)	(1,785)
Accumulated other comprehensive income	(38)	11
Treasury stock (at cost); 7,522,799 shares in 2004 and 7,097,326 shares in 2003	(224)	(222)
Unamortized compensation	(26)	(23)
Total stockholders' equity	4,032	4,474
Total liabilities and stockholders' equity	$31,795	$37,084

See accompanying notes.

EL PASO CORPORATION

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

	Nine Months Ended September 30,	
	2004	2003 (Restated) [1]
Cash flows from operating activities		
Net loss	$ (404)	$(1,643)
Less loss from discontinued operations, net of income taxes	(150)	(1,195)
Net loss before discontinued operations	(254)	(448)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	808	897
Loss on long-lived assets	789	463
Earnings from unconsolidated affiliates, adjusted for cash distributions	(592)	224
Deferred income tax expense (benefit)	88	(482)
Cumulative effect of accounting changes	—	9
Other non-cash items	153	412
Asset and liability changes	(384)	633
Cash provided by continuing operations	608	1,708
Cash provided by discontinued operations	191	58
Net cash provided by operating activities	799	1,766
Cash flows from investing activities		
Additions to property, plant and equipment	(1,246)	(1,868)
Purchases of interests in equity investments	(26)	(25)
Net proceeds from the sale of assets and investments	1,758	1,382
Cash paid for acquisitions, net of cash acquired	(47)	(1,078)
Net change in restricted cash	470	(137)
Other	108	(42)
Cash provided by (used in) continuing operations	1,017	(1,768)
Cash provided by discontinued operations	1,140	297
Net cash provided by (used in) investing activities	2,157	(1,471)
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,705)	(2,091)
Net repayments under short-term debt and credit facilities	—	(250)
Net proceeds from the issuance of long-term debt and other financing obligations	50	3,433
Dividends paid	(75)	(178)
Payments to redeem preferred interests of consolidated subsidiaries	—	(1,177)
Contributions from discontinued operations	966	355
Issuances of common stock, net	73	—
Other	(34)	20
Cash provided by (used in) continuing operations	(725)	112
Cash used in discontinued operations	(1,331)	(355)
Net cash used in financing activities	(2,056)	(243)
Increase in cash and cash equivalents	900	52
Cash and cash equivalents		
Beginning of period	1,429	1,591
End of period	$ 2,329	$ 1,643

[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 September 30,		Nine Months Ended September 30,	
	2004	2003 (Restated)	2004	2003 (Restated)
Net income (loss)	$(214)	$24	$(404)	$(1,643)
Foreign currency translation adjustments	3	4	(22)	120
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $33 and $45 in 2004 and $8 and $50 in 2003)	(47)	38	(70)	108
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $3 and $18 in 2004 and less than $1 and $27 in 2003)	4	(2)	43	(61)
Other comprehensive income (loss)	(40)	40	(49)	167
Comprehensive income (loss)	$(254)	$64	$(453)	$(1,476)

See accompanying notes.

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 September 30, 2004, and for the quarters and nine months ended September 30, 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 all periods presented have been reclassified to reflect our Canadian and certain other international natural gas and oil production operations as discontinued operations. Also, our results for the quarter and nine months ended September 30, 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 and oil production. These restatements are further discussed in our 2003 Annual Report on Form 10-K. Finally, 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, eliminating, or refinancing approximately $4.2 billion of debt and other obligations ($2.6 billion through September 30, 2004) (see Note 11);
- 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 12); and
- entering into a new credit agreement in November 2004 to refinance our previous revolving credit facility with an aggregate of $3 billion in financings consisting of a $1.25 billion, five-year term loan; a $1.0 billion, three-year revolving credit facility; and a $750 million, five-year funded letter of credit facility (see Note 11).

Liquidity Update

During 2004, we received waivers and amendments to our then existing revolving credit facility and various other financing arrangements to address events that we believe would have constituted an event of default; specifically under the provisions in those arrangements related to the timely filing of our financial statements, representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. We have filed our financial statements within the time frames granted by these waivers.

In November 2004, we replaced our previous revolving credit facility which was scheduled to mature in June 2005, with a new credit agreement with a group of lenders for an aggregate of $3 billion in financings. The new credit agreement consists of a $1.25 billion, five-year term loan; a $1 billion, three-year revolving credit facility under which we can issue letters of credit; and an additional $750 million, five-year funded letter of credit facility. The letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity as term loans. The new credit agreement is collateralized by our interests in El Paso Natural Gas Company (EPNG), Tennessee Gas Pipeline Company (TGP), ANR Pipeline Company (ANR), Colorado Interstate Gas Company (CIG), Wyoming Interstate Company Ltd. (WIC), ANR Storage Company and Southern Gas Storage Company.

Our new credit agreement provided approximately $220 million in net additional borrowing availability (after repayment of an existing obligation of approximately $229 million and various other items) as compared to our previous revolving credit facility. Upon closing of the new credit agreement, we borrowed $1.25 billion under the term loan and utilized the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to replace approximately $1.2 billion of letters of credit issued under our previous revolving credit facility.

El Paso CGP Company, our subsidiary, has not yet filed its financial statements for the third quarter of 2004, as required under several of its, and its affiliates', financing arrangements. We believe El Paso CGP's financial statements will be filed prior to any notice being given or within the allowed time frames under those arrangements such that there will be no event of default.

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 income (loss) and income (loss) per share had we applied SFAS No. 123:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Net income (loss) as reported	$ (214)	$ 24	$ (404)	$(1,643)
Add: Stock-based compensation expense in net income (loss), net of taxes	4	8	11	35
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	9	21	28	73
Pro forma net income (loss)	$ (219)	$ 11	$ (421)	$(1,681)
Income (loss) per share:				
Basic and diluted, as reported	$(0.33)	$0.04	$(0.63)	$ (2.76)
Basic and diluted, pro forma	$(0.34)	$0.02	$(0.66)	$ (2.82)

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 $9 million of third party debt as of September 30, 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 $33 million as of September 30, 2004. We deconsolidated EMA because our equity partner is allocated a majority of EMA's losses and returns through its equity interest and its fuel supply and power purchase agreements with EMA.

We have significant interests in a number of other variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of September 30, 2004, these entities consisted primarily of 21 equity investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 7,800 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 ($1.6 billion as of September 30, 2004) and our guarantees and other agreements associated with these entities (a maximum of $104 million as of September 30, 2004).

During our adoption of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity's two 250 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $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 nine months ended September 30, 2004 and 2003, and as of September 30, 2004 and December 31, 2003:

	2004	2003
	(In millions)	
Operating revenues	$(30)	$ 26
Current liabilities from price risk management activities	(19)	(28)
Non-current liabilities from price risk management activities	(30)	(6)

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 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.

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. The net carrying amounts of our goodwill as of September 30, 2004, and the changes in the net carrying amounts of goodwill for the nine months ended September 30, 2004, for each of our segments are as follows:

	Pipelines	Field Services	Corporate	Total
		(In millions)		
Balances as of January 1, 2004	$413	$ 480	$ 3	$ 896
Impairments of goodwill	—	(480)	—	(480)
Other changes	—	—	(3)	(3)
Balances as of September 30, 2004	$413	$ —	$—	$ 413

In September 2004, we completed the sale of substantially all of our interests in GulfTerra Energy Partners (GulfTerra), as well as certain processing assets in our Field Services segment, to affiliates of Enterprise Products Partners, L.P. (Enterprise). As a result of these sales, we determined that the remaining assets in our Field Services segment could not support the goodwill in this segment, and therefore, we fully impaired this amount in the third quarter of 2004. See Note 16 for a further discussion of the impact of the Enterprise transactions on our goodwill and other intangible assets during the third quarter of 2004.

New Accounting Pronouncements Not Yet Adopted

Accounting for Natural Gas and Oil Producing Activities. 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. It will also require these companies to exclude future cash outflows associated with settling asset retirement liabilities from their full cost ceiling test calculation. Finally, this standard will require disclosure of the impact of a company's asset retirement obligations on its oil and gas producing activities, ceiling test calculations and depreciation, depletion and amortization calculations. We will adopt the provisions of this pronouncement in the first quarter of 2005 and are currently evaluating its impact, if any, on our consolidated financial statements.

Accounting for Inventory Costs. In November 2004, the FASB issued SFAS No. 151, *Inventory Costs, an amendment of ARB No. 43, Chapter 4.* This statement clarifies the types of costs that should be expensed rather than capitalized as inventory. This statement also clarifies the circumstances under which fixed overhead costs associated with operating facilities involved in inventory processing should be capitalized. The provisions of SFAS No. 151 are effective for fiscal years beginning after June 15, 2005, and may impact certain inventory costs we incur after January 1, 2006. We are currently evaluating the impact, if any, of this standard on our consolidated financial statements.

Accounting for Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95.* This standard requires that companies record the fair value of their stock-based compensation arrangements as a liability or as a component of equity on the date they are granted to employees. The classification of these arrangements as liabilities or as a component of equity is based on whether the obligations can be settled in cash and/or in stock. Regardless of their treatment as liabilities or equity, these amounts are to be expensed over the vesting period of the arrangements. This standard is effective for interim periods beginning after June 15, 2005, at which time companies can select whether they will apply the standard retroactively by restating their historical financial statements or prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We will adopt this pronouncement in the third quarter of 2005 and are currently evaluating its impact on our consolidated financial statements.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB is expected to issue FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004*. FSP No. 109-2 will clarify the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement will also require companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act, and we continue to evaluate this legislation and FSP No. 109-2 to determine whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our 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 first quarter of 2003.

Gemstone. As discussed more completely in our 2003 Annual Report on Form 10-K, we acquired all of the outstanding third party interests in Gemstone for approximately $50 million in April 2003. The results of Gemstone's operations have been included in our consolidated financial statements beginning April 1, 2003. Had the acquisition been effective January 1, 2003, our revenues, operating income, and net income for the quarter ended March 31, 2003 would not have been significantly different, and basic and diluted earnings per share would have been unaffected.

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 September 30, 2004	Completed After September 30, 2004 or Announced to Date[1]	Total
	(In millions)		
Regulated			
Pipelines	$ 54	$ —	$ 54
• Australia pipelines			
• Aircraft			
• Interest in gathering systems			
Unregulated			
Production	24	—	24
• Brazilian exploration and production assets			
Power	699	184	883
• Utility Contract Funding (UCF)[2]			
• Mohawk River Funding IV[2]			
• Bastrop Company equity investment[2]			
• 25 domestic power plants under contract[3]			
• 5 other domestic power plants and turbines[2]			
Field Services	1,029	—	1,029
• General partnership interest, common units and Series C units of GulfTerra			
• South Texas processing plants			
• Dauphin Island and Mobile Bay equity investments			
Other			
Corporate	16	—	16
• Aircraft			
Total continuing	1,822[4]	184	2,006
Discontinued	1,293	2	1,295
• Natural gas and oil production properties in Canada and other international production assets[2]			
• Aruba and Eagle Point refineries and other petroleum assets[2]			
Total	$3,115	$186	$3,301

(1) Sales that have not been completed are estimates, subject to customary regulatory approvals, final negotiations and other conditions.
(2) These sales were completed as of September 30, 2004.
(3) The sales of 21 of these plants were completed as of September 30, 2004, and three additional sales were completed in the fourth quarter of 2004.
(4) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $64 million for the nine months ended September 30, 2004. Proceeds also exclude any non-cash consideration received in these sales.

Significant Assets and Investments Sold	**Proceeds (In millions)**
Through September 30, 2003	
Regulated	
Pipelines	$ 82
• Panhandle gathering system located in Texas	
• 2.1 percent interest in Alliance pipeline and related assets	
• Helium processing operations in Oklahoma	
• Table Rock sulfur extraction facility	
• Horsham pipeline in Australia	
Unregulated	
Production	678
• Natural gas and oil properties in New Mexico, Texas, Louisiana, Oklahoma and the Gulf of Mexico	
• Drilling rigs	
Power	300
• 50 percent interest in CE Generation L.L.C. power investment	
• Mt. Carmel power plant	
• Interest in Kladno power project	
• CAPSA/CAPEX investments in Argentina	
• Mohawk River Funding I, L.L.C.	
Field Services	153
• Gathering systems located in Wyoming	
• Midstream assets in the north Louisiana and Mid-Continent regions	
Other	
Corporate	113
• Aircraft	
• Enerplus Global Energy Management Company and its financial operations	
• Encap funds management business and related investments	
Total continuing	1,326(1)
Discontinued	661
• Corpus Christi refinery	
• Florida petroleum terminals and tug and barge operations	
• Louisiana lease crude business	
• Coal reserves and properties in West Virginia, Virginia and Kentucky	
• Natural gas and oil production properties in Canada	
• Petroleum asphalt facilities	
Total	$1,987

(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 $56 million for the nine months ended September 30, 2003.

See Notes 6 and 16 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 to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. These assets consist of certain of our domestic power plants and natural gas gathering and processing assets in our Field Services segment. The following table details the items that have been reflected as current assets and liabilities held for sale in our balance sheets as of September 30, 2004 and December 31, 2003.

	September 30, 2004	December 31, 2003
	(In millions)	
Assets Held for Sale		
Current assets	$ 8	$ 46
Investments in unconsolidated affiliates	137	480
Property, plant and equipment, net	99	477
Other assets	122	136
Total assets	$366	$1,139
Current liabilities	$ 2	$ 54
Long-term debt, less current maturities	132	169
Other liabilities	—	13
Total liabilities	$134	$ 236

Discontinued Operations

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of November 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During the nine months ended September 30, 2004, we recognized approximately $98 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties in early 2005.

Petroleum Markets. During 2003, our Board of Directors approved the sales of our petroleum markets businesses and operations. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax impairment charges of approximately $1,337 million during the nine months ended September 30, 2003 related to these assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately $59 million in the first nine months of 2003 from the sale of our Corpus Christi refinery, our asphalt assets, our 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 recorded realized losses of approximately $37 million in the first nine months of 2004, primarily from the sale of our Aruba and Eagle Point refineries. 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.

The petroleum markets, coal mining and our other international natural gas and oil production operations discussed above, are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of September 30, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
		(In millions)		
Operating Results Data				
Quarter Ended September 30, 2004				
Revenues	$ 44	$ 1	$ —	$ 45
Costs and expenses	(52)	(5)	—	(57)
Gain (loss) on long-lived assets	1	(5)	—	(4)
Other income	14	—	—	14
Income (loss) before income taxes	7	(9)	—	(2)
Income taxes	10	—	—	10
Loss from discontinued operations, net of income taxes	$ (3)	$ (9)	$ —	$ (12)
Quarter Ended September 30, 2003				
Revenues	$ 907	$ 20	$ —	$ 927
Costs and expenses	(953)	(57)	(1)	(1,011)
Gain (loss) on long-lived assets	8	1	(8)	1
Other expense	(2)	—	—	(2)
Interest and debt expense	(4)	1	—	(3)
Loss before income taxes	(44)	(35)	(9)	(88)
Income taxes	(5)	(42)	—	(47)
Income (loss) from discontinued operations, net of income taxes	$ (39)	$ 7	$ (9)	$ (41)
Nine Months Ended September 30, 2004				
Revenues	$ 737	$ 29	$ —	$ 766
Costs and expenses	(782)	(52)	—	(834)
Loss on long-lived assets	(37)	(98)	—	(135)
Other income	14	—	—	14
Interest and debt expense	(3)	1	—	(2)
Loss before income taxes	(71)	(120)	—	(191)
Income taxes	1	(42)	—	(41)
Loss from discontinued operations, net of income taxes	$ (72)	$ (78)	$ —	$ (150)
Nine Months Ended September 30, 2003				
Revenues	$ 4,586	$ 66	$ 27	$ 4,679
Costs and expenses	(4,697)	(104)	(22)	(4,823)
Loss on long-lived assets	(1,278)	(13)	(11)	(1,302)
Other income (expense)	(16)	—	1	(15)
Interest and debt expense	(8)	2	—	(6)
Loss before income taxes	(1,413)	(49)	(5)	(1,467)
Income taxes	(231)	(42)	1	(272)
Loss from discontinued operations, net of income taxes	$(1,182)	$ (7)	$ (6)	$(1,195)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Financial Position Data			
September 30, 2004			
Assets of discontinued operations			
Accounts and notes receivable	$ 49	$ 1	$ 50
Inventory	8	—	8
Other current assets	1	1	2
Property, plant and equipment, net	22	6	28
Other non-current assets	26	—	26
Total assets	$ 106	$ 8	$ 114
Liabilities of discontinued operations			
Accounts payable	$ 5	$ 1	$ 6
Other current liabilities	5	—	5
Other non-current liabilities	4	—	4
Total liabilities	$ 14	$ 1	$ 15
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivable	$ 259	$ 22	$ 281
Inventory	385	3	388
Other current assets	131	8	139
Property, plant and equipment, net	521	399	920
Other non-current assets	70	6	76
Total assets	$1,366	$438	$1,804
Liabilities of discontinued operations			
Accounts payable	$ 172	$ 39	$ 211
Other current liabilities	86	—	86
Long-term debt	374	—	374
Other non-current liabilities	26	3	29
Total liabilities	$ 658	$ 42	$ 700

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 for the nine months ended September 30:

	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate	Total
			(In millions)				
2004							
Employee severance, retention and transition costs	$5	$12	$ 2	$4	$1	$11	$ 35
Office relocation and consolidation	—	—	—	—	—	30	30
	$5	$12	$ 2	$4	$1	$41	$ 65
2003							
Employee severance, retention and transition costs	$1	$ 4	$10	$4	$3	$40	$ 62
Contract termination costs	—	—	—	—	—	44	44
	$1	$ 4	$10	$4	$3	$84	$106

Our 2004 restructuring costs consisted of employee severance costs which included severance payments and costs for pension benefits settled under existing benefit plans, as well as office relocation and consolidation costs. As of September 30, 2004, substantially all of the employee severance, retention and transition costs had been paid. For further information on our office relocation and consolidation costs, see the discussion below.

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 were recorded in the first quarter of 2003 and 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 announced that we would begin consolidating our Houston-based operations into one location. This 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 we no longer utilize the leased space. 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 lease obligation, net of estimates for sub-lease payments, will be approximately $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 $32 million. In addition, we subleased approximately 210,000 square feet in the third and fourth quarters of 2004. Actual moving expenses related to the relocation will be expensed in the period that they are incurred. All amounts related to the relocation will be expensed in our corporate activities.

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 intangible assets that are a part of our continuing operations. During each of the periods ended September 30, our loss on long-lived assets was as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Net realized (gain) loss	$ 6	$ 10	$ (8)	$ (6)
Goodwill impairments	480	—	480	163
Impairments of long-lived assets	64	44	317	306
Loss on long-lived assets	$550	$ 54	$789	$463

Net Realized (Gain) Loss

Our 2004 net realized gains are primarily related to an $8 million gain on aircraft sales associated with our corporate activities. Our Power segment also recorded net gains of approximately $5 million related to the sales of 6 of our domestic power plants. These gains were partially offset by an $11 million loss on the sale of our South Texas processing assets in our Field Services segment. Our 2003 net realized gain was primarily related to a $14 million gain on the sale of our north Louisiana and Mid-Continent midstream assets in our Field Services segment, a $6 million gain on the Table Rock sulfur extraction facility in our Pipelines segment, and a $5 million gain on the sale of non-full cost pool assets in our Production segment. Partially offsetting these gains were $10 million of losses related to the sale of Mohawk River Funding I in our Power segment and $8 million of losses related to the sales of assets associated with our corporate activities in 2003.

Asset and Goodwill Impairments

Our 2004 asset and goodwill impairments primarily occurred in our Field Services and Power segments. Our Field Services segment recorded a $480 million impairment of its goodwill that resulted from the sale of substantially all of our interests in GulfTerra, as well as our processing assets in south Texas to affiliates of Enterprise in the third quarter of 2004 (see Note 16). We also recorded $7 million of impairments in the second quarter of 2004 in our Field Services segment, primarily related to miscellaneous assets that will no longer be used because of various asset sales. Our Field Services segment also recorded a $13 million impairment in the third quarter of 2004 on our Indian Springs natural gas gathering and processing assets to adjust the carrying value of these assets to their expected sales price. In the first quarter of 2004, our Power segment recorded a $135 million impairment related to our Manaus and Rio Negro power plants in Brazil and a $98 million impairment related to the sale of our subsidiary, UCF, which owns a restructured power contract. The impairments in Brazil were primarily due to events in the first quarter of 2004 that may make it difficult to extend the plants' power sales agreements that expire in 2005 and 2006. See Note 12 for a further discussion of the matters related to Brazil. Our Power segment also recorded $62 million of impairments on our domestic power plants to adjust the carrying value of these plants to their expected sales price. Of the $62 million of impairments, $52 million was recorded in the third quarter.

Our 2003 impairment charges primarily related to our telecommunications and LNG operations, both included in our corporate activities. Our telecommunications operations recorded charges of $396 million, which included a $269 million impairment charge (including a $163 million writedown of goodwill) related to our investment in the wholesale metropolitan transport services, primarily in Texas and an impairment of our Lakeside Technology Center facility of $127 million based on probability-weighted scenarios of what the asset could be sold for in the current market. We also recorded $37 million of impairments on our LNG assets and a $22 million impairment on turbines classified as non-current assets in our Power segment as a result of our plan to reduce our involvement in that business.

7. Income Taxes

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions, except rates)			
Income taxes	$ 77	$62	$ 124	$(451)
Effective tax rate	(62)%	49%	(95)%	51%

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 nine months of 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the GulfTerra transaction and impairments of certain of our foreign investments. The sale of our interests in GulfTerra associated with the merger between GulfTerra and Enterprise in September 2004 resulted in a significant taxable gain (compared to a lower book gain) and significant tax expense due to the non-deductibility of a significant portion of the goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense by approximately $139 million. See Note 16 for a further discussion of the merger and related transactions. Additionally, on the impairment of certain of our foreign investments, primarily during the first quarter of 2004, we received no U.S. federal income tax benefit. The combination of these items resulted in an overall tax expense for a period in which there was a pre-tax loss.

In 2004, Congress proposed but failed to enact legislation which would disallow deductions for certain settlements made to or on behalf of governmental entities. We expect Congress to reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax assets. In such event, our tax expense would increase. Our total tax assets related to the Western Energy Settlement were approximately $400 million as of September 30, 2004.

8. Earnings Per Share

We have excluded 17 million and 16 million of potentially dilutive securities for the quarters ended September 2004 and 2003, and 16 million of potentially dilutive securities for the nine months ended September 30, 2004 and 2003, from the determination of diluted earnings per share (as well as their related income statement impacts) due to their antidilutive effect on income (loss) per common share. The excluded securities included stock options, trust preferred securities and convertible debentures.

9. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of September 30, 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.

	September 30, 2004	December 31, 2003
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (46)	$ (31)
Derivatives from power contract restructuring activities	905	1,925[1]
Other commodity-based derivative contracts[2]	(752)	(488)
Total commodity-based derivatives	107	1,406
Interest rate and foreign currency hedging derivatives[3]	128	123
Net assets from price risk management activities[4]	$ 235	$1,529

(1) Includes $942 million of derivative contracts sold in connection with the sales of UCF and Mohawk River Funding IV in 2004.

(2) In December 2004, we designated other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production, and, as a result, we will reclassify this amount to derivatives designated as hedges in the fourth quarter of 2004. As of September 30, 2004 these contracts had a fair value loss of $567 million.

(3) During the nine months ended September 30, 2004, we entered into new cross currency hedge transactions that convert €100 million of our fixed rate Euro-denominated debt into $121 million of floating rate debt.

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

10. Inventory

We have the following inventory recorded on our balance sheets:

	September 30, 2004	December 31, 2003
	(In millions)	
Materials and supplies and other	$132	$145
Natural gas liquids and natural gas in storage	22	36
Total current inventory	$154	$181

11. Debt, Other Financing Obligations and Other Credit Facilities

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

	September 30, 2004	December 31, 2003
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 1,506	$ 1,401
Short-term financing obligations	48	56
Total short-term financing obligations	$ 1,554	$ 1,457
Long-term financing obligations	$17,673	$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 Increase/ Reduction in Debt	Due Date
			(In millions)		
Issuances and other increases					
Macae	Non-recourse note	LIBOR + 4.25%	$ 50	$ 50	2007
Blue Lake Gas Storage[(1)]	Non-recourse term loan	LIBOR + 1.2%	14	14	2006
	Increases through September 30, 2004		64	64	
El Paso[(2)]	Notes	6.50%	213	213	2005
El Paso[(3)]	Term loan	LIBOR + 2.75%	1,250	1,250	2009
	Increases through date of filing		$1,527	$1,527	
Repayments, repurchases and other retirements					
El Paso CGP	Note	LIBOR + 3.5%	$ 200	$ 200	
El Paso	Revolver	LIBOR + 3.5%	850	850	
Gemstone	Notes	7.71%	202	202	
El Paso CGP	Note	6.2%	190	190	
Mohawk River Funding IV[(4)]	Non-recourse note	7.75%	72	72	
Utility Contract Funding[(4)]	Non-recourse senior notes	7.944%	815	815	
Other	Long-term debt	Various	263	263	
	Decreases through September 30, 2004		2,592	2,592	
Gemstone	Notes	7.71%	748	748	
Lakeside	Note	LIBOR + 3.5%	271	271	
El Paso CGP	Notes	10.25%	38	38	
El Paso[(2)]	Notes	6.50%	213	213	
El Paso[(5)]	Zero coupon debenture	—	103	104	
El Paso	Note	6.88%	14	15	
El Paso CGP	Note	7.5%	55	58	
El Paso CGP	Note	6.50%	91	94	
El Paso	Note	6.75%	21	22	
El Paso	Medium-term notes	Various	28	28	
Other	Long-term debt	Various	11	11	
	Decreases through date of filing		$4,185	$4,194	

(1) This debt was consolidated as a result of adopting FIN No. 46 (see Note 2).

(2) In the fourth quarter of 2004, we entered into an agreement with Enron that liquidated two derivative swap agreements (reflected in other current and other non-current liabilities in our balance sheet as of September 30, 2004) in exchange for approximately $213 million of 6.5% one year notes. Subsequent to the closing of our new credit agreement, these notes were paid in full.

(3) Proceeds from the $1.25 billion term loan under the new credit agreement entered into in November 2004.

(4) This debt was eliminated when we sold our interests in Mohawk River Funding IV and UCF.

(5) In December 2004, we repurchased these 4% yield-to-maturity zero-coupon debentures. The amount shown as principal is the carrying value on the date the debt was retired as compared to its maturity value in 2021 of $196 million.

Credit Facilities

During 2004, we received waivers and amendments to our then existing revolving credit facility and various other financing arrangements to address events that we believe would have constituted an event of default; specifically under the provisions in those arrangements related to the timely filing of our financial statements, representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. All conditions to these waivers have now been met.

In November 2004, we replaced our previous revolving credit facility, which was scheduled to mature in June 2005, with a new credit agreement with a group of lenders for an aggregate of $3 billion in financings. As of September 30, 2004, we had no outstanding borrowings, but had $1.1 billion of letters of credit issued under our previous revolving credit facility. The new credit agreement provides approximately $220 million in net additional borrowing availability (after repayment of our Lakeside Technology Center obligation of approximately $229 million and various other items), as compared with the borrowing availability under our previous revolving credit facility. This new credit agreement consists of a $1.25 billion five-year term loan; a $1 billion three-year revolving credit facility; and a $750 million, five-year funded letter of credit facility. Certain of our subsidiaries, EPNG, TGP, ANR and CIG, also continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement which is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company and Southern Gas Storage Company.

Upon closing of the new credit agreement, we borrowed $1.25 billion under the term loan and utilized the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to replace approximately $1.2 billion of letters of credit issued under our previous revolving credit facility. The term loan bears interest at LIBOR plus 2.75 percent, matures in November 2009, and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the new revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent, or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. Finally, under the terms of the new credit agreement, certain lenders funded a $750 million letter of credit facility that provides us the ability to issue letters of credit or borrow any unused capacity under the letter of credit facility as term loans with a maturity in November 2009. We pay LIBOR plus 2.75 percent on any amounts borrowed under the letter of credit facility, and 2.85 percent on letters of credit and unborrowed funds.

Restrictive Covenants

Our restrictive covenants includes restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our new credit agreement the significant debt covenants and cross defaults are:

(a) El Paso's ratio of Debt to Consolidated EBITDA, each as defined in the new credit agreement, shall not exceed 6.50 to 1.0 at any time prior to September 30, 2005, 6.25 to 1.0 at any time on or after September 30, 2005 and prior to June 30, 2006, and 6.00 to 1.0 at any time on or after June 30, 2006 until maturity;

(b) El Paso's ratio of Consolidated EBITDA, as defined in the new credit agreement, to interest expense plus dividends paid shall not be less than 1.60 to 1.0 prior to March 31, 2006, 1.75 to 1.0 on or after March 31, 2006 and prior to March 31, 2007, and 1.80 to 1.0 on or after March 31, 2007 until maturity;

(c) EPNG, TGP, ANR, and CIG cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the new credit agreement, for that particular company to exceed 5 to 1;

(d) the proceeds from the issuance of Debt by our pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt; and

(e) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to Debt in an aggregate principal amount of $200 million or more.

In addition to the above restrictions and default provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in our cash management program, and limitations on our ability to prepay debt.

El Paso CGP Company, our subsidiary, has not yet filed its financial statements for the third quarter of 2004, as required under several of its and its affiliates financing arrangements. We believe El Paso CGP's financial statements will be filed prior to any notice being given or within the allowed time frames under those arrangements such that there will be no event of default.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of September 30, 2004, we had outstanding letters of credit of approximately $1.2 billion, of which $1.1 billion was outstanding under our previous revolving credit facility and $65 million was supported with cash collateral. Included in this amount were $0.8 billion of letters of credit securing our recorded obligations related to price risk management activities. Prior to the closing of our new credit agreement, we had approximately $1.2 billion of letters of credit issued pursuant to our previous revolving credit facility. We used the new $750 million letter of credit facility and approximately $0.4 billion of the new $1.0 billion revolving credit facility to replace these issued letters of credit.

12. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2004, our master settlement agreement, along with other separate settlement agreements, became effective with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada 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, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA described above with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. During the nine months ended September 30, 2003, we recorded additional pretax charges of $103 million based upon reaching definitive settlement agreements. Charges and expenses associated with the Western Energy Settlement are included in operations and maintenance expense in our consolidated statements of income. In June 2004, the settlement became effective and $602 million was released to the settling parties. This amount is shown as a reduction of our cash flows from operations in the second quarter of 2004. Of the amount released, $568 million has been previously held in an escrow account pending final approval of the settlement. The release of these restricted funds is included as an increase in our cash flows from investing activities. Our remaining obligation as of September 30, 2004 under the Western Energy Settlement consists of a discounted 20-year cash payment obligation of $386 million and a price reduction under a power supply contract, which is included in our price risk management activities. In connection with the Western Energy Settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining cash payment obligation. The collateral requirement is being reduced as payments under the 20 year obligation are made. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 7.

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 raised issues of market power and was a violation of the FERC's marketing 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. In November 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 in March 2004. In April 2004, certain shippers appealed both FERC orders on this matter to the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument before the court of appeals was held in October 2004.

Shareholder Class Action Suits. Beginning in July 2002, 12 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 12th 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.

Beginning in February 2004, 17 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 in July 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 the Sarbanes-Oxley Act of 2002 against certain of the individually named defendants.

Our costs and exposures in these lawsuits are not currently determinable. We are currently evaluating each of these cases as to their merits, our defenses, their possible settlement and potential insurance recoveries.

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 was subsequently 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.

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

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. A number of our subsidiaries were named defendants in actions filed in 1997 brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). 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 in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action has since been filed as to the heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et. al. v. El Paso Natural Gas Company, et. al.,* and *Deane W. Moore, et. al. v. Burlington Northern, Inc., et. al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs seek an accounting and damages for alleged royalty underpayments from 1983 to the present on natural gas produced from specified wells in Oklahoma, plus interest from the time such amounts were allegedly due, as well as punitive damages. The plaintiffs have filed expert reports alleging damages in excess of $1 billion. While Burlington accepted our tender of defense in 1997 pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Northern, Inc., and had been defending the matter since that time, it has recently asserted contractual claims for indemnity against us. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties are proceeding with discovery. In March 2004, the court dismissed all claims brought on behalf of the class of overriding royalty interest owners, but denied defendant's other motions for summary judgment. In September 2004, the court granted several motions made by Burlington that have the effect of partially reducing the plaintiffs' claims, but denied Burlington's motion to preclude interest payments on any amounts found to be owing to plaintiffs. The written order on such motions has not been issued yet and in the interim, the case is being reassigned to another trial judge due to conflict issues. It is anticipated that this matter will be scheduled for trial during 2005. A third action, styled *Bank of America, et. al. v. El Paso Natural Gas and Burlington Resources Oil & Gas Company*, was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity. In December 2004, EPNG and El Paso Production Company were served with another purported royalty class action lawsuit alleging the failure to pay royalties on oil produced from the South Erick Field in Beckham County, Oklahoma commencing in 1957. We believe that EPNG and El Paso Production are entitled to a defense and indemnity in this action from Burlington under the spin-off agreement of 1992. 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 59 such lawsuits nationwide, which have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs 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 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 hedges of our natural gas and oil production.

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

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand jury subpoenas for documents with regard to these reserve revisions. We are cooperating with the SEC's and the U.S. Attorney's investigations of this matter.

Storage Reporting. In 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. In August 2004, the CFTC announced they had completed the investigation and found no evidence of wrongdoing. In November 2004, ANR and TGP received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the EIA for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR and TGP provided information on their weekly EIA submissions for the weeks ending November 12, 2004 and November 19, 2004. Neither ANR nor TGP's submissions to the EIA were revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC. We are cooperating with the CFTC's request.

Iraq Oil Sales. In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations' Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records relating to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with the Oil for Food Program. We have also received an inquiry from the United States Senate's Permanent Subcommittee of Investigations related to a specific transaction in 2000.

In September 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 cooperating with the U.S. Attorney's, the SEC's and the Senate Subcommittee's investigations of this matter.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations. In December 2003, the matter was referred to the Department of Justice.

After a public hearing conducted by the National Transportation Safety Board (NTSB) on its investigation into the Carlsbad rupture, the NTSB published its final report in April 2003. The NTSB stated that it had determined that the probable cause of the August 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program.

In November 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture and cooperated fully in responding to the subpoena. That subpoena has since expired. In December 2003 and January 2004, eight current and former employees were served with testimonial subpoenas issued by the grand jury. Six individuals testified in March 2004. In April 2004, we and EPNG received a new federal grand jury subpoena requesting additional documents. We have responded fully to this subpoena. Two additional employees testified before the grand jury in June 2004.

A number of 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.

A lawsuit entitled *Baldonado et. al. v. EPNG* was filed in June 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. Plaintiff's filed their brief and request for oral argument in November 2004. EPNG will file its brief 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. Parties to four of the settled lawsuits filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas in November 2002, seeking additional sums based upon their interpretation of earlier settlement agreements. This matter has been settled and dismissed.

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 September 30, 2004, we had approximately $522 million 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 September 30, 2004, we had accrued approximately $389 million, including approximately $381 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $8 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $389 million accrual, $145 million was reserved for facilities we currently operate, and $244 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 $389 million to approximately $550 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 ($81 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($308 million to $469 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.

	September 30, 2004	
Sites	**Expected**	**High**
	(In millions)	
Operating	$145	$190
Non-operating	213	314
Superfund	31	46
Total	$389	$550

Below is a reconciliation of our accrued liability from January 1, 2004, to September 30, 2004 (in millions):

Balance as of January 1, 2004	$412
Additions/adjustments for remediation activities	8
Payments for remediation activities	(32)
Other changes, net	1
Balance as of September 30, 2004	$389

For the remainder of 2004, we estimate that our total remediation expenditures will be approximately $18 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 September 30, 2004, TGP had pre-collected PCB costs by approximately $124 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 September 30, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $95 million for estimated future refund obligations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 61 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of September 30, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $46 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws 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.

Rates and Regulatory Matters

Proposed Release Regarding Pipeline Integrity Costs. In November 2004, the FERC issued an industry-wide Proposed Accounting Release that, if enacted as written, would require our interstate pipelines to expense rather than capitalize certain costs that are part of our pipeline integrity program. The accounting release is proposed to be effective January 2005 following a period of public comment on the release. We are currently reviewing the release and have not quantified the impact this release will have on our consolidated financial statements.

Inquiry Regarding Income Tax Allowances. On December 2, 2004, the FERC issued a notice of inquiry in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC seeks comments on whether the court's reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines, including those pipelines that are not owned by a corporate entity, such as Great Lakes Gas Transmission Limited Partnership which is jointly owned with unaffiliated parties.

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 (EPM) owed it approximately $3 million, and that EPM 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, EPM maintained that EPMI owed EPM $30 million due to the termination of a physical power contract, which is included in the $317 million of filed claims. EPMI filed a lawsuit against EPM and its guarantor, El Paso, 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 for which final payments were made in the third quarter of 2004. 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 that time.

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

Investments in Brazil. We own and have investments in power, pipeline and production assets in Brazil with an aggregate exposure, including financial guarantees, of approximately $1.6 billion as of September 30, 2004. During 2002, Brazil experienced higher interest rates on local debt for the government and private sectors, which 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 and interest rate levels decreased. 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 its economic situation. Some of the specific issues 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 Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $184 million at September 30, 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 $35 million at September 30, 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 $39 million at September 30, 2004. Manaus Energia purchases power from both projects through long-term PPAs. However, the Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. 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. Several non-governmental organizations obtained a preliminary injunction enjoining Manaus Energia from proceeding with the bid process until a decision on the merits of their complaint was made, but that injunction has now been lifted, and Manaus Energia received bids in December 2004. We continue to negotiate PPA term extensions and have received an offer from Manaus Energia to extend the term of the Manaus and Rio Negro PPAs. Also, 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 that has resulted in a long-term receivable of $32 million which is a subject of this lawsuit. Based on the bid process and the expected outcome of our negotiations to extend the term of the PPAs, we recorded an impairment charge of approximately $135 million in the first quarter of 2004. We also recorded a $32 million charge in operation and maintenance expense in our Power segment in the third quarter of 2004 as a valuation allowance for our overall exposure in these two projects. We recorded this valuation allowance based on our current expectation of recoverable amounts based on further negotiations that have taken place in the fourth quarter of 2004.

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 PPAs. 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 PPAs 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 PPAs and the proposed amendments do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment was $284 million at September 30, 2004. In October 2004, the project experienced an outage associated with one of its steam turbine generators, which resulted in a partial reduction in the plant's capacity. We expect to replace or repair the steam turbine during 2005.

We own a 895 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil with a net book value of $707 million at September 30, 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. 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 September 30, 2004, we had approximately $55 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 September 30, 2004, we had accrued $78 million related to these arrangements.

13. Retirement Benefits

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

	Quarter Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003	2004	2003	2004	2003
	(In millions)							
Service cost	$ 8	$ 9	$—	$—	$ 24	$ 27	$—	$—
Interest cost	30	33	9	9	91	101	25	27
Expected return on plan assets	(47)	(57)	(3)	(2)	(142)	(171)	(9)	(6)
Amortization of net actuarial loss	12	1	1	—	36	3	3	—
Amortization of transition obligation	—	—	2	2	—	—	6	6
Amortization of prior service cost(1)	(1)	(1)	—	—	(3)	(3)	—	—
Settlements, curtailment, and special termination benefits(2)	(5)	—	—	—	(5)	—	—	(6)
Net benefit cost (income)	$ (3)	$(15)	$ 9	$ 9	$ 1	$ (43)	$25	$21

(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.

(2) We recognized curtailments in 2004 and 2003 related to a reduction in the number of employees that participate in our pension and other postretirement plans, which resulted from our various asset sales and employee severance efforts in 2004 and 2003.

We made $59 million and $72 million of cash contributions to our Supplemental Executive Retirement Plan and other postretirement plans during the nine months ended September 30, 2004 and 2003. We expect to contribute an additional $2 million to the Supplemental Executive Retirement Plan and $10 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 will adopt a new accounting standard in the fourth quarter of 2004 that we believe will not materially affect our previously reported benefit information and our net benefit cost for the year ending December 31, 2004.

Retirement Savings Plan

As of June 25, 2004, participants in our retirement savings plan were temporarily suspended from making future contributions, or transferring other investment funds, to the El Paso Corporation Stock Fund. This temporary suspension was necessary because El Paso was not current with all of its SEC filings. The suspension will be lifted after we become current with our SEC filings.

See Note 12 for an additional matter that could impact our retirement benefit obligations.

14. Capital Stock

Common Stock

In January 2004, we issued 8.8 million shares of common stock for $74 million, less issuance costs of $1 million, to satisfy the remaining stock obligation under our Western Energy Settlement.

Dividends

During the nine months ended September 30, 2004, we paid dividends of $75 million to common stockholders. We have also paid dividends of approximately $25 million subsequent to September 30, 2004. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit. On November 18, 2004, the Board of Directors declared a quarterly dividend of $0.04 per share on the company's outstanding stock. The dividend will be payable on January 3, 2005 to shareholders of record on December 3, 2004. In addition, El Paso Tennessee Pipeline Co., our subsidiary, pays dividends (2.0625% per quarter, 8.25% per annum) of approximately $6 million each quarter on its Series A cumulative preferred stock.

15. 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 continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements. Our operating results for all periods presented reflect these changes.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the periods ended September 30:

	Quarter Ended September 30, 2004	Quarter Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
Total EBIT	$ 277	$ 609	$ 1,117	$ 507
Interest and debt expense	(396)	(475)	(1,229)	(1,352)
Distributions on preferred interests of consolidated subsidiaries	(6)	(7)	(18)	(45)
Income taxes	(77)	(62)	(124)	451
Income (loss) from continuing operations	$(202)	$ 65	$ (254)	$ (439)

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

Quarter Ended September 30,	Regulated: Pipelines	Unregulated: Production	Unregulated: Marketing and Trading	Unregulated: Power	Unregulated: Field Services	Corporate[1]	Total
			(In millions)				
2004							
Revenues from external customers	$582	$ 92[2]	$ 176	$188	$ 370	$ 21	$1,429
Intersegment revenues	22	308[2]	(296)	(7)	56	(83)	—
Operation and maintenance	204	96	15	134	19	39	507
Depreciation, depletion and amortization	104	136	4	14	3	9	270
(Gain) loss on long-lived assets	—	—	—	45	506	(1)	550
Operating income (loss)	$218	$147	$(139)	$(48)	$(477)	$ (56)	$ (355)
Earnings from unconsolidated affiliates	43	1	—	25	548	—	617
Other income	7	2	1	18	2	6	36
Other expense	—	—	—	(2)	(12)	(7)	(21)
EBIT	$268	$150	$(138)	$ (7)	$ 61	$ (57)	$ 277
2003							
Revenues from external customers	$572	$ (5)[2]	$ 476	$353	$ 229	$ 29	$1,654
Intersegment revenues	26	457[2]	(394)	(30)	97	(96)	60[3]
Operation and maintenance	157	96	38	146	30	(14)	453
Depreciation, depletion and amortization	95	136	9	23	7	13	283
(Gain) loss on long-lived assets	(1)	10	—	41	2	2	54
Operating income (loss)	$267	$183	$ 35	$ 26	$ (8)	$ (22)	$ 481
Earnings from unconsolidated affiliates	28	1	—	9	41	—	79
Other income	6	1	(6)	35	—	13	49
Other expense	—	—	(1)	(3)	(1)	5	—
EBIT	$301	$185	$ 28	$ 67	$ 32	$ (4)	$ 609

(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 operations.

Nine Months Ended September 30,	Regulated Pipelines	Unregulated Production	Unregulated Marketing and Trading	Unregulated Power	Unregulated Field Services	Corporate[1]	Total
	(In millions)						
2004							
Revenues from external customers	$1,875	$ 369[2]	$ 544	$ 539	$1,090	$ 93	$4,510
Intersegment revenues	67	907[2]	(964)	85	151	(246)	—
Operation and maintenance	556	258	38	328	70	31	1,281
Depreciation, depletion and amortization	305	407	10	42	10	34	808
(Gain) loss on long-lived assets	(1)	—	—	285	514	(9)	789
Operating income (loss)	$ 826	$ 552	$ (468)	$(180)	$ (460)	$ (50)	$ 220
Earnings from unconsolidated affiliates	117	4	—	78	616	—	815
Other income	21	2	6	66	2	42	139
Other expense	(2)	—	—	(8)	(34)	(13)	(57)
EBIT	$ 962	$ 558	$ (462)	$ (44)	$ 124	$ (21)	$1,117
2003							
Revenues from external customers	$1,882	$ 145[2]	$ 1,129	$ 781	$ 885	$ 97	$4,919
Intersegment revenues	89	1,610[2]	(1,711)	127	377	(300)	192[3]
Operation and maintenance	658	272	107	457	100	40	1,634
Depreciation, depletion and amortization	291	435	22	70	25	54	897
(Gain) loss on long-lived assets	(9)	5	(3)	36	(3)	437	463
Operating income (loss)	$ 763	$ 928	$ (712)	$ 89	$ (23)	$(572)	$ 473
Earnings (losses) from unconsolidated affiliates	96	11	—	(94)	28	(10)	31
Other income	21	4	9	70	—	28	132
Other expense	(5)	—	(1)	(9)	(2)	(112)	(129)
EBIT	$ 875	$ 943	$ (704)	$ 56	$ 3	$(666)	$ 507

(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 operations.

Total assets by segment are presented below:

	September 30, 2004	December 31, 2003
	(In millions)	
Regulated		
Pipelines	$15,867	$15,753
Unregulated		
Production	4,057	3,767
Marketing and Trading	1,987	2,666
Power	4,565	7,074
Field Services	688	1,990
Total segment assets	27,164	31,250
Corporate	4,517	4,030
Discontinued operations	114	1,804
Total consolidated assets	$31,795	$37,084

16. 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. The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates, including affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest.

	Quarter Ended September 30,					Nine Months Ended September 30,				
	GulfTerra	Citrus	Great Lakes	Other Investments	Total	GulfTerra	Citrus	Great Lakes	Other Investments	Total
	(In millions)									
2004										
Operating results data:										
Operating revenues	$141	$64	$31	$353	$589	$406	$178	$99	$1,117	$1,800
Operating expenses	93	21	15	275	404	259	69	41	839	1,208
Income from continuing operations	30	18	9	46	103	90	44	33	153	320
Net income[(1)]	30	18	9	46	103	90	46	33	153	322
2003										
Operating results data:										
Operating revenues	$169	$59	$31	$458	$717	$556	$170	$96	$1,518	$2,340
Operating expenses	111	28	15	349	503	401	73	43	1,062	1,579
Income from continuing operations	39	14	7	57	117	96	29	27	267	419
Net income[(1)]	39	14	7	57	117	96	29	27	267	419

(1) Includes net income of $3 million and $1 million for the quarters ended September 30, 2004 and 2003, and $24 million and $6 million for the nine months ended September 30, 2004 and 2003, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

Our income statement reflects our share of net earnings from unconsolidated affiliates, which includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments. The table below reflects our earnings (losses) from unconsolidated affiliates for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Proportional share of income of investees	$103	$117	$322	$ 419
Impairment charges and gains and losses on sale of investments				
Gain on sale of GulfTerra interests	511	—	511	—
Chaparral impairment[1]	—	—	—	(207)
Milford power facility impairment[2]	—	(2)	(2)	(88)
Dauphin Island/Mobile Bay impairment[3]	—	—	—	(80)
Power plants held for sale impairments[3]	(15)	—	(50)	—
Linden Venture impairment[4]	—	(22)	—	(22)
Gain on sales of CAPSA/CAPEX	—	—	—	24
Other gains (losses)	10	(1)	10	(14)
Gain on issuance of GulfTerra common units	1	3	4	15
Other	7	(16)	20	(16)
Total earnings from unconsolidated affiliates	$617	$ 79	$815	$ 31

(1) 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).

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

(3) These impairments resulted from the anticipated sales of these investments, which were substantially completed in the third quarter of 2004.

(4) This impairment resulted from the anticipated loss from the sale of East Coast Power, L.L.C., which was completed in the fourth quarter of 2003.

We received distributions and dividends from our investments of $72 million and $116 million for each of the quarters ended September 30, 2004 and 2003, and $240 million and $273 million for the nine months ended September 30, 2004 and 2003.

Related Party Transactions

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Operating revenue	$75	$86	$236	$213
Other revenue — management fees	(2)	5	3	11
Cost of sales	31	26	91	85
Reimbursement for operating expenses	27	34	93	102
Other income	1	3	6	8
Interest income	2	3	6	9
Interest expense	—	—	—	3

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

In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we sold to affiliates of Enterprise substantially all of our interests in GulfTerra, which had a carrying value of approximately $519 million. This value included an indefinite lived intangible asset of $181 million and minority interest of $84 million directly related to our GulfTerra interests. In the transaction, we sold our interest in the general partner of GulfTerra, 10.9 million GulfTerra Series C units, 2.9 million GulfTerra common units and miscellaneous administrative assets to Enterprise for $870 million of cash and 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. As of September 30, 2004, we have approximately $256 million of investments in unconsolidated affiliates on our balance sheet related to Enterprise. Concurrent with the sale of our investment, we also sold nine of our processing plants located in south Texas to Enterprise for $156 million of cash.

As a result of the Enterprise transactions, we recorded a $511 million gain in earnings from unconsolidated affiliates from the sale of our interests in GulfTerra, an $11 million loss on long-lived assets from closing adjustments related to the sale of our south Texas processing assets and a $480 million impairment of the goodwill associated with our Field Services segment in the third quarter of 2004. See Note 2 for a further discussion of the goodwill impairment. The net income statement impact of the Enterprise transactions was a pre-tax gain of $20 million. Approximately $397 million of the goodwill impairment will not be deductible for tax purposes and, as a result, we recognized tax expense of approximately $146 million associated with the Enterprise transactions in the third quarter of 2004.

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 periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Revenues received from GulfTerra				
Marketing and Trading	$ 4	$ 6	$ 19	$22
Field Services	—	—	1	5
	$ 4	$ 6	$ 20	$27
Expenses paid to GulfTerra				
Field Services	$25	$14	$ 77	$56
Marketing and Trading	8	8	25	27
Production	3	3	7	7
	$36	$25	$109	$90
Reimbursements received from GulfTerra				
Field Services	$24	$22	$ 69	$68

For a further discussion of our relationship 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.

During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements for all periods presented. In addition, our results for the quarter and nine months ended September 30, 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.

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 Item 1, Financial Statements, Note 4);
- retiring, eliminating, or refinancing approximately $4.2 billion of maturing debt and other obligations ($2.6 billion through September 30, 2004) (see Item 1, Financial Statements, Note 11);
- 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 Item 1, Financial Statements, Note 12); and
- entering into a new credit agreement in November 2004 to refinance our previous revolving credit facility with an aggregate of $3 billion in financings consisting of a $1.25 billion, five-year term loan; a $1.0 billion three-year revolving credit facility; and a five-year, $750 million funded letter of credit facility (see Item 1, Financial Statements Note 11).

Liquidity Update

During 2004, we received waivers and amendments to our then existing revolving credit facility and various other financing arrangements to address events that we believe would have constituted an event of default; specifically under the provisions in those arrangements related to the timely filing of our financial statements, representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. We have filed our financial statements within the time frames granted by these waivers.

In November 2004, we replaced our previous revolving credit facility which was scheduled to mature in June 2005 with a new credit agreement with a group of lenders for an aggregate of $3 billion in financings. The new credit agreement consists of a $1.25 billion, five-year term loan; a $1 billion, three-year revolving credit facility under which we can issue letters of credit, and an additional $750 million, five-year funded letter of credit facility. The letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity as a term loan. The new credit agreement is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company and Southern Gas Storage Company.

Our new credit agreement provides approximately $220 million in net additional borrowing availability (after repayment of an existing obligation of approximately $229 million and various other items) as compared with our previous revolving credit facility. Upon closing of the new credit agreement, we borrowed $1.25 billion under the term loan, utilized the $750 million under the letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to replace approximately $1.2 billion of letters of credit issued under our previous revolving credit facility. We will use the proceeds from the $1.25 billion term loan to repay certain financing obligations (see Item 1, Financial Statements, Note 11), manage our liquidity, prepay upcoming debt maturities, and provide for other general corporate purposes.

The availability of borrowings under the new credit agreement and other borrowing agreements is subject to various conditions as further described in Item 1, Financial Statements, Note 11, 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. As of September 30, 2004, our ratio of Debt to Consolidated EBITDA was 4.74 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 1.92 to 1, each as defined in the credit agreement.

El Paso CGP Company, our subsidiary, has not yet filed its financial statements for the third quarter of 2004, as required under several of its, and its affiliates', financing arrangements. We believe El Paso CGP's financial statements will be filed prior to any notice being given or within the allowed time frames under those arrangements such that there will be no event of default.

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 new credit agreement, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, 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 nine months ended September 30, 2004, we continued to reduce our overall debt and securities of subsidiaries as part of our Long-Range Plan announced in December 2003. Our activity during the nine months ended September 30, 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 and other increases	64
Repayments/retirements of principal[(1)]	(1,705)
Sales of entities[(2)]	(887)
Other	(58)
Total debt and securities of subsidiaries as of September 30, 2004	$19,593

(1) Amount excludes $370 million of 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) This debt was eliminated when we sold our interests in Mohawk River Funding IV and Utility Contract Funding.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Item 1, Financial Statements, Note 11.

Capital Resources and Liquidity

Overview of Cash Flow Activities for the Nine Months Ended September 30, 2004 and 2003

For the nine months ended September 30, 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	$ (254)	$ (448)
Non-cash income adjustments	1,246	1,523
Changes in assets and liabilities	(384)	633
Cash flows from continuing operating activities	608	1,708
Cash flows from continuing investing activities	1,017	(1,768)
Cash flows from continuing financing activities	(725)	112
Change in cash and cash equivalents related to continuing operations	900	52
Discontinued operations		
Cash flows from operating activities	191	58
Cash flows from investing activities	1,140	297
Cash flows from financing activities	(1,331)	(355)
Change in cash and cash equivalents related to discontinued operations	—	—
Total change in cash and cash equivalents	$ 900	$ 52

During the first nine months 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 from continuing operations	
Cash flows from operating activities	$ 0.6
Net proceeds from the sale of assets and investments	1.8
Net change in restricted cash(1)	0.5
Cash provided from discontinued operations	1.0
Total cash inflows from continuing operations	3.9
Cash outflows from continuing operations	
Additions to property, plant and equipment	(1.3)
Payments to retire long-term debt	(1.7)
Total cash outflows from continuing operations	(3.0)
Cash flows from discontinued operations	
Cash from operations	0.2
Net proceeds from sale of assets	1.2
Payments to retire long-term debt	(0.4)
Cash provided to continuing operations	(1.0)
Total net cash inflows from discontinued operations	—
Net increase in cash	$ 0.9

(1) Amounts consist primarily of the release of escrowed funds related to the Western Energy Settlement.

As of November 30, 2004, we had available cash on hand and borrowing capacity under our new credit agreement totaling $2.7 billion.

Cash From Continuing Operating Activities

Overall, cash generated from our continuing operating activities was $0.6 billion during the first nine months of 2004 versus $1.7 billion during the same period of 2003. The $1.1 billion decrease in operating cash flow was largely due to a payment of $0.6 billion to settle the principal litigation under the Western Energy Settlement in the second quarter of 2004, $0.3 billion of greater cash recoveries in 2003 for margin calls compared to 2004 and the loss of cash generation related to assets sold during the last year.

Cash From Continuing Investing Activities

Net cash provided by our continuing investing activities was $1.0 billion for the nine months ended September 30, 2004. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$(0.6)
Pipeline expansion, maintenance and integrity projects	(0.7)
Restricted cash activity[1]	0.5
Proceeds from the sale of assets and investments	1.8
Total continuing investing activities	$ 1.0

(1) Amounts consist primarily of the release of escrowed funds related to the Western Energy Settlement.

For the remainder of 2004, we expect our total capital expenditures to be approximately $0.7 billion, which includes approximately $0.3 billion for our Production segment and $0.4 billion for our Pipelines segment.

Cash From Continuing Financing Activities

Net cash used by our continuing financing activities was $0.7 billion for the nine months ended September 30, 2004. Cash used in our financing activities included net repayments of $1.7 billion made to retire third party long-term debt and cash dividend payments of $0.1 billion to shareholders. Cash provided from our financing activities included $1.0 billion of cash generated by our discontinued operations, as further discussed below, and $0.1 billion from the issuances of common stock. We reflect the net cash generated by our discontinued operations as a cash inflow to our continuing financing activities.

Cash from Discontinued Operations

During the first nine months of 2004, our discontinued operations contributed $1.0 billion of cash. We generated $0.2 billion in cash in these operations, received proceeds from the sales of assets primarily related to our Eagle Point and Aruba refineries and our western Canada production operations of approximately $1.2 billion, and repaid $0.4 billion of long-term debt related to the Aruba refinery.

Commodity-based Derivative Contracts

We use derivative financial instruments in our hedging activities, power contract restructuring activities and in our historical energy trading activities. The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of September 30, 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	$ 15	$ 13	$ —	$ —	$ —	$ 28
Liabilities	(23)	(25)	(15)	(11)	—	(74)
Total derivatives designated as hedges	(8)	(12)	(15)	(11)	—	(46)
Assets from power contract restructuring derivatives[1]	130	266	210	299	—	905
Other commodity-based derivatives						
Exchange-traded positions[2]						
Assets	—	117	79	3	—	199
Liabilities	(79)	(2)	—	—	—	(81)
Non-exchange-traded positions						
Assets	225	302	133	166	44	870
Liabilities[1]	(542)	(722)	(217)	(212)	(47)	(1,740)
Total other commodity-based derivatives[3]	(396)	(305)	(5)	(43)	(3)	(752)
Total commodity-based derivatives	$(274)	$ (51)	$ 190	$ 245	$ (3)	$ 107

(1) Includes $251 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 nine months ended September 30, 2004.

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

(3) In December 2004, we designated other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production and, as a result, we will reclassify this amount to derivatives designated as hedges in the fourth quarter of 2004. As of September 30, 2004 these contracts had a fair value loss of $567 million.

Below is a reconciliation of our commodity-based derivatives for the period from January 1, 2004 to September 30, 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	39	(1,099)[1]	183	(877)
Change in fair value of contracts	(54)	79	(444)[2]	(419)
Option premiums received, net	—	—	(3)	(3)
Net change in contracts outstanding during the period	(15)	(1,020)	(264)	(1,299)
Fair value of contracts outstanding at September 30, 2004	$(46)	$ 905	$(752)	$ 107

(1) Includes $861 million and $75 million of derivative contracts sold in connection with the sales of Utility Contract Funding and Mohawk River Funding IV in 2004. See Item I, Financial Statements, Notes 4 and 6 for additional information on these sales.

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

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

The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement 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 activities include our general and administrative functions as well as a telecommunications business and various other contracts and assets. 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. In the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements. Our operating results for all periods presented reflect these changes.

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 income (loss) for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Regulated Businesses				
Pipelines	$ 268	$ 301	$ 962	$ 875
Unregulated Businesses				
Production	150	185	558	943
Marketing and Trading	(138)	28	(462)	(704)
Power	(7)	67	(44)	56
Field Services	61	32	124	3
Segment EBIT	334	613	1,138	1,173
Corporate	(57)	(4)	(21)	(666)
Consolidated EBIT from continuing operations	277	609	1,117	507
Interest and debt expense	(396)	(475)	(1,229)	(1,352)
Distributions on preferred interests of consolidated subsidiaries	(6)	(7)	(18)	(45)
Income taxes	(77)	(62)	(124)	451
Income (loss) from continuing operations	(202)	65	(254)	(439)
Discontinued operations, net of income taxes	(12)	(41)	(150)	(1,195)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(9)
Net income (loss)	$(214)	$ 24	$ (404)	$(1,643)

Overview of Results of Operations

For the nine months ended September 30, 2004, our consolidated EBIT from continuing operations was $1,117 million of which $1,138 million was our segment EBIT. During the nine months, our Pipelines, Production and Field Services segments contributed $1,644 million of combined EBIT. These positive contributions were partially offset by combined EBIT losses of $506 million in our Power and Marketing and Trading segments. The following overview summarizes the results of operations by operating segments compared to our internal expectations for the period.

Pipelines — Our Pipelines segment generated EBIT of $962 million, which was generally consistent with our expectations for the period.

Production — Our Production segment generated EBIT of $558 million, which was above our expectations for the period. 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 on our full cost pool assets, more than offset lower than expected production volumes and higher than expected production costs.

Marketing and Trading — Our Marketing and Trading segment generated an EBIT loss of $462 million, which was a greater loss than our expectations. The performance was driven primarily by mark-to-market losses in our natural gas portfolio due to natural gas price increases in the period. Our natural gas portfolio exposure was also impacted by the hedge restatement in periods prior to 2004, resulting in a mark-to-market position that generates losses if natural gas prices increase.

Power — Our Power segment generated an EBIT loss of $44 million, which was below our expectations for the period, primarily due to asset impairments and other charges, net of realized gains and losses, of $362 million. These impairments and charges were primarily related to events at two power plants in Brazil in

2004 related to difficulties in extending their power sales agreements that expire in 2005 and 2006, and due to certain of our domestic operations which were sold or are being sold.

Field Services Our Field Services segment generated EBIT of $124 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. However, this volatility should decrease as a result of the designation of certain of our derivatives as hedges of our Production segment's natural gas production in the fourth quarter of 2004.

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 nine months ended September 30, see the discussions of the individual segment and other results that follow, as well as Item 1, Financial Statements, Notes 5, 6, and 16.

	Operating Segments					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate
			(In millions)			
Nine Months Ended September 30, 2004						
Asset and investment impairments, net of gain (loss) on sale	$ 4	$ —	$ —	$(330)	$ (3)[1]	$ 9
Restructuring charges	(5)	(12)	(2)	(4)	(1)	(41)
Total	$ (1)	$(12)	$ (2)	$(334)	$ (4)	$ (32)
2003						
Asset and investment impairments, net of gain (loss) on sale	$ 9	$ (5)	$ 3	$(335)	$(76)	$(446)
Restructuring charges	(1)	(4)	(10)	(4)	(3)	(84)
Western Energy Settlement[2]	(138)	—	(17)	—	—	(3)
Total	$(130)	$ (9)	$(24)	$(339)	$(79)	$(533)

(1) Includes a net gain of $500 million on the sale for our GulfTerra interests and other assets to Enterprise and a related goodwill impairment of $480 million in the third quarter of 2004. See Item 1, Financial Statements, Notes 2, 6 and 16 for a further discussion of these sales, gains and impairments.

(2) Includes $55 million of accretion expense and other charges and is included in operations and maintenance expense in our consolidated statements of income.

The following is a discussion of the comparative quarterly and nine month period results, including a discussion of the items above, for 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 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 periods ended September 30:

Pipelines Segment Results	Quarter Ended September 30, 2004	Quarter Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions, except volume amounts)			
Operating revenues	$ 604	$ 598	$ 1,942	$ 1,971
Operating expenses	(386)	(331)	(1,116)	(1,208)
Operating income	218	267	826	763
Other income	50	34	136	112
EBIT	$ 268	$ 301	$ 962	$ 875
Throughput volumes (BBtu/d)[1]	19,480	18,786	20,637	20,430

(1) Throughput volumes exclude volumes related to our equity investments in the Portland Natural Gas Transmission System and EPIC Energy Australia Trust which were sold in the fourth quarter of 2003 and second quarter of 2004. In addition, volumes 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)

Some of the key issues affecting our Pipeline segment operations for the periods ending September 30, 2004 include the impact on revenues and operating expenses of our efforts to recontract available capacity, the benefit from selling excess fuel over the amount needed to operate the facilities and higher operating costs, mainly higher allocated corporate overhead. Additionally, in 2003 we completed our settlement of energy disputes in the Western United States referred to as the Western Energy Settlement.

The following factors contributed to our overall EBIT decrease of $33 million for the quarter ended September 30, 2004 and EBIT increase of $87 million for the nine months ended September 30, 2004 as compared to the same periods ended September 30, 2003:

	Quarter Ended September 30, Revenue	Expense	Other	EBIT	Nine Months Ended September 30, Revenue	Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
Contract modifications/terminations	$(14)	$ 10	$—	$ (4)	$(86)	$ 37	$—	$(49)
Fuel recoveries, net of gas used/system supply costs	20	(12)	—	8	29	(9)	—	20
Mainline expansions	8	(2)	(1)	5	27	(5)	(4)	18
Western Energy Settlement in 2003	—	(20)	—	(20)	—	138	—	138
Higher operation and maintenance costs[1]	—	(20)	—	(20)	—	(35)	—	(35)
Change to regulated depreciation method	—	(2)	—	(2)	—	(7)	—	(7)
Equity earnings from Citrus	—	—	6	6	—	—	12	12
Mexico investments	2	(1)	4	5	7	(4)	12	15
Other[2]	(10)	(8)	7	(11)	(6)	(23)	4	(25)
Total	$ 6	$(55)	$16	$(33)	$(29)	$ 92	$24	$ 87

(1) Consists of costs of operations, electric and power purchase costs, overhead allocation and environmental costs.

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

The renegotiation or restructuring of several contracts on our pipeline systems including our contracts with We Energies 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 gasification facility contract on its system. However, the termination of this contract will not have a significant overall impact on operating income and EBIT.

Included in contract modifications/terminations above are the impact of the expiration of EPNG risk sharing provisions, which provided revenue net of sharing obligation. The provisions expired at the end of 2003, and will continue to unfavorably impact our comparative EBIT, for the remainder of 2004. In addition, while the impact of EPNG's capacity pool obligation for former full requirements (FR) customers terminated with the completion of Phases I and II of EPNG's Line 2000 Power-up project in 2004, EPNG remains at risk for that portion of capacity which was turned back to it on a permanently released basis. EPNG is able, however, to re-market that capacity subject to the general requirement that EPNG demonstrate that any sale of capacity does not adversely impact its service to its firm customers.

Our pipeline 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 approximately $26 million, at which time this amount will be reflected in earnings.

In September 2004, we incurred significant damage to sections of our TGP and SNG offshore pipeline facilities due to Hurricane Ivan. Cost estimates are currently in the $80 to $95 million range with damage assessment still in progress. We expect insurance reimbursement for the cost of the damage with the exception of our share of a $2 million deductible applied on a corporate-wide basis.

In November 2004, the FERC issued an industry-wide Proposed Accounting Release that, if enacted as written, would require our interstate pipelines to expense rather than capitalize certain costs that are part of our pipeline integrity program. The accounting release is proposed to be effective January 2005 following a period of public comment on the release. We are currently reviewing the release and have not determined the impact, if any, this release will have on our consolidated financial statements.

Unregulated Businesses — Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities with a long-term strategy of developing production opportunities primarily in the U.S. and Brazil. In July 2004, we acquired an additional 50 percent interest in UnoPaso to increase our production operations in Brazil. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs and sell our products at attractive prices.

We are currently divesting our international production properties that are not part of our long-term strategy and, as of November 2004, have sold all of our Canadian operations and substantially all of our operations in Indonesia. Beginning in the second quarter of 2004, these operations have been treated as discontinued operations as further discussed in Item 1, Financial Statements, Note 4. All periods reflect this change.

Production and Capital Expenditures

For the nine months ended September 30, 2004, our total equivalent production has declined approximately 95 Bcfe or 30 percent as compared to the same period in 2003 primarily due to normal production declines, asset sales and disappointing drilling results. We expect our fourth quarter of 2004 production to average approximately 765 MMcfe/d and our 2004 annual production to average approximately 810 MMcfe/d. The 2004 projected annual production average excludes approximately 15 MMcfe/d related to our discontinued operations. Our expected fourth quarter 2004 production levels in the Gulf of Mexico will be negatively impacted by Hurricane Ivan that occurred in September 2004. This hurricane caused us to shut-in production and also caused damage to third party facilities that process or transport our production. We continue to experience reduced production levels in this region as a result of the damage and do not expect to return to full production until mid-2005.

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. Future trends in production will be 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.

Through September 2004, we have spent $588 million in capital expenditures for acquisition, exploration, and development activities. Based on the results to date of our 2004 drilling program, we expect our domestic unit of production depletion rate to increase from $1.74 per Mcfe for the third quarter of 2004 to $1.80 per Mcfe for the fourth quarter of 2004.

Production Hedging

We hedge our natural gas and oil production through the use of derivatives to stabilize cash flows and reduce the risk of downward commodity price movements on our sales. Our current hedging strategy only partially reduces our exposure to downward movements in commodity prices and, as a result, our reported results of operations, financial position and cash flows continue to be impacted by movements in commodity prices from period to period. In December 2004, we designated certain of the derivatives in our Marketing and Trading segment as hedges of 205 TBtu of our future natural gas production in order to reduce the earnings volatility in our Marketing and Trading segment. These derivative hedge designations will have no impact on El Paso's cash flow in any period, but will impact the timing of recognizing earnings in El Paso's overall operating results. Below are the hedging positions on our anticipated natural gas and oil production as of the date of this filing for 2005 and forward. For the fourth quarter of 2004, we have 1,615 Bbtu of anticipated natural gas production hedged at an average price of $3.92/MMbtu.

Natural Gas

	Quarters Ended									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume (Bbtu)	Hedged Price /MMbtu	Volume (Bbtu)	Hedged Price /MMbtu	Volume (Bbtu)	Hedged Price /MMbtu	Volume (Bbtu)	Hedged Price /MMbtu	Volume (Bbtu)	Hedged Price /MMbtu
2005	33,019	$6.75	33,037	$6.75	33,055	$6.75	33,055	$6.75	132,166	$6.75
2006	21,349	$6.34	21,367	$6.34	21,385	$6.34	21,385	$6.34	85,486	$6.34
2007	1,579	$3.79	1,447	$3.64	1,155	$3.35	1,155	$3.35	5,336	$3.56
2008 and beyond									20,620	$3.67

Oil

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

In addition to the hedges listed above, we further reduced our overall exposure to commodity price fluctuations in future periods by entering into put contracts in our Marketing and Trading segment in November 2004 which are designed to provide protection on a consolidated basis from natural gas price declines in 2005 and 2006. These "put" contracts do not qualify as accounting hedges and will be marked-to-market in the operating results of our Marketing and Trading segment. These contracts will provide El Paso with a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006. El Paso paid a premium of approximately $67 million, or $0.37 per MMBtu, for the transactions and, as a result, will have no future cash margin requirements under the contracts.

Operating Results

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
Production Segment Results	**2004**	**2003**	**2004**	**2003**
	(In millions, except volumes and prices)			
Operating revenues:				
Natural gas	$ 325	$ 385	$ 1,056	$ 1,511
Oil, condensate and liquids	75	70	218	239
Other	—	(3)	2	5
Total operating revenues	400	452	1,276	1,755
Transportation and net product costs[1]	(13)	(17)	(40)	(67)
Total operating margin	387	435	1,236	1,688
Operating expenses:				
Depreciation, depletion and amortization	(136)	(136)	(407)	(435)
Production costs[2]	(58)	(55)	(144)	(169)
Ceiling test and other charges[3]	(1)	(15)	(12)	(14)
General and administrative expenses	(47)	(44)	(120)	(135)
Taxes, other than production and income taxes	2	(2)	(1)	(7)
Total operating expenses[1]	(240)	(252)	(684)	(760)
Operating income	147	183	552	928
Other income	3	2	6	15
EBIT	$ 150	$ 185	$ 558	$ 943
Volumes, prices and costs per unit:				
Natural gas				
Volumes (MMcf)	59,282	76,646	186,516	267,763
Average realized prices including hedges ($/Mcf)[4]	$ 5.48	$ 5.02	$ 5.66	$ 5.64
Average realized prices excluding hedges ($/Mcf)[4]	$ 5.53	$ 5.08	$ 5.73	$ 5.77
Average transportation costs ($/Mcf)	$ 0.18	$ 0.15	$ 0.16	$ 0.19
Oil, condensate and liquids				
Volumes (MBbls)	2,013	2,851	6,660	9,020
Average realized prices including hedges ($/Bbl)[4]	$ 37.32	$ 24.84	$ 32.81	$ 26.55
Average realized prices excluding hedges ($/Bbl)[4]	$ 37.44	$ 25.45	$ 32.85	$ 27.28
Average transportation and net product costs ($/Bbl)	$ 1.00	$ 1.13	$ 1.24	$ 1.03

Production Segment Results	Quarter Ended September 30, 2004	Quarter Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions, except volumes and prices)			
Production costs ($/Mcfe)				
Average lease operating costs	$ 0.67	$ 0.50	$ 0.55	$ 0.40
Average production taxes	0.14	0.09	0.09	0.13
Total production cost[1]	$ 0.81	$ 0.59	$ 0.64	$ 0.53
Average general and administrative expenses ($/Mcfe)	$ 0.65	$ 0.47	$ 0.53	$ 0.42
Unit of production depletion cost ($/Mcfe)	$ 1.75	$ 1.35	$ 1.66	$ 1.27

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

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

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

(4) Prices are stated before transportation costs.

Quarter Ended September 30, 2004 Compared to Quarter Ended September 30, 2003

EBIT. For the quarter ended September 30, 2004, EBIT was $35 million lower than the same period in 2003. The decrease in EBIT was primarily due to lower production volumes due to normal production declines and disappointing drilling results. Partially offsetting these decreases were higher natural gas and oil prices and lower operating expenses.

Operating Revenues. The following table describes the variance in revenue between the quarters ended September 30, 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.

Production Revenue Variance Analysis	Variance Prices	Variance Volumes	Variance Hedges	Total
		(In millions)		
Natural gas	$27	$ (88)	$ 1	$ (60)
Oil, condensate and liquids	24	(21)	2	5
	$51	$(109)	$ 3	(55)
Other				3
Total operating revenue variance				$ (52)

For the quarter ended September 30, 2004, operating revenues were $52 million lower than the same period in 2003 due to lower production volumes, partially offset by higher natural gas and oil prices. The decline in production volumes was primarily due to normal production declines in our offshore Gulf of Mexico and Texas Gulf Coast regions and disappointing drilling results. Production in the third quarter of 2004 was also impacted by Hurricane Ivan that occurred in September 2004 in the Gulf of Mexico that caused us to shut-in production and also caused damage to third party facilities that process or transport our production. These declines were partially offset by production increases as a result of our acquisition of the remaining third-party interest in UnoPaso, which we consolidated in July 2004.

Average realized natural gas prices for the third quarter of 2004, excluding hedges, were $0.45 per Mcf higher than the same period in 2003, an increase of nine percent. In addition, our natural gas hedging losses decreased from $4 million in 2003 to $3 million in 2004. We expect hedging losses to continue for the remainder of 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 $12 million lower for the third quarter of 2004 as compared to the third quarter of 2003 primarily due to ceiling test charges incurred in Brazil in third quarter of 2003 and the impairment of a non-full cost pool asset in the third quarter of 2003. These decreases were partially offset by slightly higher production costs and general and administrative expenses in the third quarter of 2004 as compared to the same period in 2003. During the fourth quarter of 2004, we expect to incur additional depreciation of approximately $7 million related to the relocation of our offices in Houston, Texas.

Total depreciation, depletion, and amortization expense remained unchanged in the third quarter of 2004 as compared to the same period in 2003. Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense by $30 million. Offsetting this decrease were higher depletion rates due to higher finding and development costs which contributed an increase of $29 million.

Production costs increased by $3 million in the third quarter of 2004 as compared to the same period in 2003 due to slightly higher production taxes and lease operating expenses. On a per Mcfe basis, production taxes increased $0.05 in 2004 due to higher natural gas and oil prices. Additionally, our total production costs per Mcfe increased $0.22 as lease operating expenses increased $0.17 per Mcfe due to the lower production volumes discussed above.

General and administrative expenses increased $3 million in the third quarter of 2004 as compared to the same period in 2003. The increase on a per unit basis was primarily due to lower production volumes. For the fourth quarter of 2004, we expect our corporate overhead allocations to be approximately the same as the third quarter 2004 allocations.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

EBIT. For the nine months ended September 30, 2004, EBIT was $385 million lower than the same period in 2003. The decrease in EBIT was primarily due to lower production volumes due to normal production declines, asset sales and disappointing drilling results. Partially offsetting these decreases were higher oil prices and lower operating expenses.

Operating Revenues. The following table describes the variance in revenue between the nine months ended September 30, 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.

	Variance			
Production Revenue Variance Analysis	**Prices**	**Volumes**	**Hedges**	**Total**
		(In millions)		
Natural gas	$(8)	$(469)	$22	$(455)
Oil, condensate and liquids	37	(64)	6	(21)
	$29	$(533)	$28	(476)
Other				(3)
Total operating revenue variance				$(479)

For the nine months ended September 30, 2004, operating revenues were $479 million lower than the same period in 2003 due to lower production volumes and lower natural gas prices partially offset by higher oil prices and a decrease in our hedging losses. The decline in production volumes was primarily due to normal production declines in the offshore Gulf of Mexico and Texas Gulf Coast regions, the sale of properties in New Mexico, Oklahoma, and offshore Gulf of Mexico as well as disappointing drilling results. Our average production for the nine months ended September 30, 2004 was also impacted by Hurricane Ivan that occurred in September 2004 in the Gulf of Mexico. The hurricane caused us to shut-in production and also caused damage to third party facilities that process or transport our production. These declines were partially offset by production increases as a result of our acquisition of the remaining third-party interest in UnoPaso, which we consolidated in July 2004.

Operating Expenses. Total operating expenses were $76 million lower in 2004 as compared to the same period in 2003 primarily due to lower depreciation, depletion, and amortization expense, lower production costs, and lower general and administrative expenses. In addition, in 2003 we incurred a ceiling test charge in

Brazil and recognized an impairment of non-full cost pool assets. Partially offsetting these decreases were higher employee severance costs in 2004. During the fourth quarter of 2004, we expect to incur additional depreciation expense of approximately $7 million related to the relocation of our offices in Houston, Texas.

Total depreciation, depletion, and amortization expense decreased by $28 million in 2004 as compared to the same period in 2003. Lower production volumes in 2004 due to asset sales and other production declines discussed above reduced our depreciation, depletion, and amortization expenses by $121 million. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs which contributed an increase of $88 million.

Production costs decreased by $25 million in 2004 as compared to the same period in 2003 primarily due to a decrease in production taxes resulting from high cost gas well tax credits in 2004 and to lower production volumes in 2004 compared to 2003. On a per Mcfe basis, production taxes decreased $0.04 in 2004. However, our total production costs per Mcfe increased $0.11 as lease operating expenses increased $0.15 per Mcfe due to the lower production volumes discussed above.

General and administrative expenses decreased $15 million in 2004 as compared to the same period in 2003. The decrease was primarily due to lower corporate overhead allocations. However, the costs per unit increased $0.11 per Mcfe due to lower production volumes. For the fourth quarter of 2004, we expect our corporate overhead allocations to be approximately the same as the third quarter 2004 allocations.

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 has resulted in increased earnings volatility in our mark-to-market portfolio in 2004 due to changes in natural gas prices. For a further discussion of the restatement, refer to our 2003 Annual Report on Form 10-K.

In December 2004, to reduce the earnings volatility in our mark-to-market portfolio, we designated certain of our fixed price natural gas derivatives as hedges of the natural gas production in our Production segment. These transactions will reduce our mark-to-market earnings exposure to future natural gas price changes. These derivative hedge designations will have no impact on El Paso's overall cash flow in any period, but will impact the timing of recognizing earnings in El Paso's overall operating results.

In the fourth quarter of 2004, we entered into additional transactions designed to provide overall protection to El Paso from natural gas price declines in 2005 and 2006. These "put" contracts will provide El Paso with a floor price of $6.00 per MMBtu on 60 TBtu of our Production segment's natural gas production in 2005 and 120 TBtu in 2006. Under these contracts, we will generally have 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. We paid a premium of approximately $67 million, or $0.37 per MMBtu, for the transactions and, as a result, will have no future cash margin requirements under the contracts.

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 periods ended September 30:

Marketing and Trading Segment Results

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Gross margin[1]	$(120)	$ 82	$(420)	$(583)
Operating expenses	(19)	(47)	(48)	(129)
Operating income (loss)	(139)	35	(468)	(712)
Other income (expense)	1	(7)	6	8
EBIT	$(138)	$ 28	$(462)	$(704)

(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.

Quarter Ended September 30, 2004 Compared to Quarter Ended September 30, 2003

For the quarter ended September 30, 2004, our gross margin decreased by $202 million compared to the same period in 2003. This decrease was primarily due to a $102 million decrease in the fair value of our derivatives, principally our natural gas contracts, during 2004 compared to a $151 million increase in the fair value of our trading positions during 2003. We sell natural gas at a fixed price in many of our trading contracts. In the third quarter of 2004, natural gas prices increased, resulting in a decrease in the fair value of these derivatives, whereas in the third quarter of 2003, natural gas prices decreased, resulting in an increase in the fair value of these derivatives. In addition, our Cordova derivative tolling agreement's fair value decreased by $27 million in 2004 compared to a $19 million increase in 2003. The Cordova power plant sells the power it generates into a power market that was incorporated into the Pennsylvania/New Jersey/Maryland (PJM) power pool in May 2004. We believe that this will improve the Cordova power plant's ability to sell its power into the marketplace and, as a result, will improve the liquidity of our tolling contract with that power plant. This also changed the relationship between the forecasted power and natural gas prices used to determine the fair value of our Cordova tolling agreement. We believe that these changes will improve the overall value of the contract and will reduce the volatility of the fair value of the contract in the future. However, we continue to evaluate the impact that this change will have on the fair value of the Cordova tolling agreement over its term, which extends through 2019. Also contributing to the decrease in gross margin were settlement losses on non-derivative contracts of $37 million in 2004 compared to $36 million in 2003, which primarily related to demand charges we could not recover on existing transportation contracts. Partially offsetting these decreases was $69 million of net gains related to the early termination of some of our derivative and non-derivative contracts in 2004, compared to $5 million of losses in 2003. Our 2004 gain primarily related to the final receipt of $50 million of proceeds from the termination of an LNG contract at our Elba Island facility and a $25 million gain on the termination of a power contract with our Power segment. The $25 million gain was eliminated from El Paso's consolidated results. We may incur future losses on the early termination of our derivative and non-derivative contracts in connection with future asset sales by other segments. Specifically, we are currently negotiating the assignment of our Cedar Brakes I and II power supply agreements which, if completed, could result in losses in the period the agreement is reached.

For the quarter ended September 30, 2004, our operating expenses decreased by $28 million compared to the same period in 2003. This decrease was primarily due to a $16 million decrease in operating expenses of our London office, which was closed in 2003. Also contributing to the decrease was $11 million of amortization expense on the Western Energy Settlement obligation that was transferred to our corporate operations in late 2003.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

For the nine months ended September 30, 2004, our gross margin improved by $163 million compared to the same period in 2003. This improvement was primarily due to $69 million of gains related to the early termination of some of our derivative and non-derivative contracts in 2004 compared to $46 million of losses in 2003. Our 2004 gains resulted primarily from the termination of our Elba Island LNG contract and a power contract with our Power segment, while our 2003 losses resulted from the active liquidation of the derivative and non-derivative positions in our trading portfolio in 2003. Our non-derivative contracts also had settlement losses of $105 million in 2004 compared to $131 million in 2003, which primarily related to demand charges we could not recover on existing transportation contracts. We expect that these demand charges will be lower than those in 2003 as we continue to experience the benefits of previous contract terminations. Also contributing to this improvement was a $371 million decrease in the fair value of our derivatives, principally our natural gas contracts, during 2003 compared to a $345 million decrease in the fair value of our trading positions during 2004. Included in the 2003 fair value decrease was $81 million of losses incurred on the settlement of our natural gas contracts in the first quarter of 2003. These losses resulted from a high volume of settlements and significant increases in natural gas prices during each of the first three months of 2003. Partially offsetting these improvements was a decrease in our Cordova derivative tolling agreement's fair value of $30 million in 2004 compared to a $26 million increase in 2003.

For the nine months ended September 30, 2004, our operating expenses decreased by $81 million compared to the same period in 2003. This decrease was primarily due to a $37 million decrease in payroll and other general and administrative expenses, including lower corporate overhead allocations that resulted from our cost reduction efforts in 2003 and 2004 and a $30 million decrease in operating expenses of our London office, which was closed in 2003. Also contributing to the decrease was $33 million of amortization expense on the Western Energy Settlement obligation that was transferred to our corporate operations in late 2003. This amortization expense was offset by a $25 million reduction in the accrual for the Western Energy Settlement obligation that resulted from the finalization of the payment schedule under the definitive settlement agreement in June 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 the operating results, a summary of the operating results of each of its activities and an analysis of these results for the periods ended September 30:

Power Segment Results	Quarter Ended September 30, 2004	Quarter Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
Gross margin[1]	$ 155	$ 246	$ 509	$ 680
Operating expenses	(203)	(220)	(689)	(591)
Operating income (loss)	(48)	26	(180)	89
Other income (expense)	41	41	136	(33)
EBIT	$ (7)	$ 67	$ (44)	$ 56
Domestic Power				
Domestic power plant operations	(55)	(10)	(47)	(221)
Domestic power contract restructuring business	22	38	(18)	119
International Power				
Brazilian power operations	25	61	(3)	134
Other international power operations	17	17	61	84
Other[2]	(16)	(39)	(37)	(60)
EBIT	$ (7)	$ 67	$ (44)	$ 56

(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.

(2) 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 third quarter of 2003, we also recorded a $22 million impairment of a power turbine in these operations.

Domestic Power Plant Operations

As of September 30, 2004, we had interests in ten domestic power plants, of which seven were classified as held for sale. Four of the power plants held for sale are contracted to be sold to a subsidiary of AIG, and three of these sales were completed in the fourth quarter of 2004. We plan on selling the remaining three merchant power plants held for sale in the near term and, as a result of the continuing negotiations of these sales, we determined that the carrying value of the plants should be reduced to the expected sales proceeds in the third quarter of 2004, which is included in the impairment discussion below.

Quarter Ended September 30, 2004 Compared to Quarter Ended September 30, 2003

Our domestic power plant operations generated an EBIT loss of $55 million in 2004 compared to an EBIT loss of $10 million in 2003. In 2004, we recognized impairments, net of realized gains and losses, of $57 million on our domestic power plants to adjust the carrying value of these plants to their expected sales price. Our remaining domestic power plants that are held for sale generated EBIT of $10 million in 2004 compared to $5 million in 2003. We also incurred a $25 million loss on the termination of a power contract with our Marketing and Trading segment in the third quarter of 2004. This loss was eliminated from El Paso's consolidated results. In 2003, we recognized $29 million of impairments on our East Coast Power facilities related to the sale of these facilities in the fourth quarter of 2003. The East Coast Power facilities also generated $22 million of operating income during 2003. We also had $12 million of equity losses on our investment in the Orlando power plant in 2003, which was sold in July 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

For the nine months ended September 30, 2004, the EBIT generated by our domestic power plant operations was $174 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, an $88 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 and $29 million of impairments on our East Coast Power facilities. In 2004, we recognized impairments, net of realized gains and losses, of $102 million on our domestic power plants to adjust the carrying value of these held for sale plants to the expected sales price. Offsetting this net increase was lower operating income in 2004 of $66 million from our East Coast Power facilities which were sold during 2003 and lower operating income of $9 million from our power plants that were sold during 2004. Our remaining power plants that are held for sale generated EBIT of approximately $19 million in 2004 compared to $6 million in 2003. Also offsetting the increase was a $25 million loss on the termination of a power contract with our Marketing and Trading segment. This loss was eliminated from El Paso's consolidated results.

Domestic Power Contract Restructuring Business

Quarter Ended September 30, 2004 Compared to Quarter Ended September 30, 2003

Our domestic power contract restructuring business relates to the continued performance under our previously restructured power derivative contracts, which are recorded at fair value. For the quarter ended September 30, 2004, the EBIT generated by our domestic power contract restructuring business was $16 million lower than the same period in 2003. This decrease was primarily due to an increase of $21 million in the fair value of our restructured power contracts in 2004 compared to an increase of $41 million in 2003. This difference was primarily due to lower accretion of the discounted value of these contracts in 2004 compared to 2003 due to the sale of Utility Contract Funding and its restructured power contract in 2004.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

For the nine months ended September 30, 2004, the EBIT generated by our domestic power contract restructuring business was $137 million lower than the same period in 2003. This decrease was primarily due to the sale of Utility Contract Funding and its restructured power contract and related debt, which resulted in a $98 million impairment loss during 2004. We also expect to sell our wholly owned subsidiaries, Cedar Brakes I and II which own restructured power contracts that are recorded at fair value. We expect to sell these entities for less than their carrying value, which we anticipate will result in a loss of approximately $220 million in the period the sales agreements are finalized. Our EBIT was also lower in 2004 as compared to 2003 because the fair value of our restructured power contracts increased by $110 million in 2003 compared to $79 million in 2004. This difference was primarily due to lower accretion of the discounted value of these contracts in 2004 compared to 2003 due to the sale of Utility Contract Funding and its restructured power contract in 2004.

International Power Plant Operations

Quarter Ended September 30, 2004 Compared to Quarter Ended September 30, 2003

Brazil. Our Brazilian operations include our Macae, Manaus, Rio Negro and Porto Velho power plants. For the quarter ended September 30, 2004, the EBIT generated by our Brazilian power plant operations decreased by $36 million compared to the same period in 2003. We are in negotiations to amend or extend the power agreements for our Manaus and Rio Negro power facilities. Based on the status of these negotiations, we recorded a $32 million charge to operation and maintenance expense in the third quarter of 2004 based on our current expectations of the recoverability of our invested amounts in these facilities. Also contributing to the decrease was a $2 million decrease in the operating income at the Porto Velho power plant. In the fourth quarter of 2004, the Porto Velho power plant experienced an equipment failure that will temporarily reduce the gross capacity of the plant from 404 MW to 284 MW. We expect that this failure will reduce our EBIT for the fourth quarter of 2004 and for 2005.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

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 interests in the Macae and Porto Velho power plants. As a result, our operating results during the first quarter of 2003 include the equity earnings we earned from Gemstone, while our consolidated operating results for all other periods in 2003 and 2004 include the revenues, expenses and equity earnings from Gemstone's assets.

For the nine months ended September 30, 2004, the EBIT generated by our Brazilian power plant operations decreased by $137 million compared to the same period in 2003. Our 2004 EBIT loss primarily resulted from $135 million of impairments and a $32 million charge in operation and maintenance expense related to our Manaus and Rio Negro power plants. We recorded these charges based on the status of our expectations of the recoverability of our invested amounts in these facilities based on the status of our negotiations to extend their power sales agreements that expire in 2005 and 2006. Partially offsetting these losses was $129 million of operating income from our Macae power plant and $20 million from our Porto Velho power plant in 2004.

Our 2003 EBIT included $17 million of equity earnings from Gemstone, which primarily included the operating results from the Macae and Porto Velho power plants above and the cost of the debt held by Gemstone during the first three months of 2003. During the second and third quarters of 2003, our Macae and Porto Velho power plants generated operating income of $89 million and $17 million.

Other International. For the nine months ended September 30, 2004, the EBIT generated by our other international power operations was $23 million lower than the same period in 2003. The decrease was primarily due to a $24 million gain on the sale of our CAPSA/CAPEX investments in Argentina in 2003. Also contributing to the decrease was $11 million of EBIT generated by our investments in Mexico in 2003, the majority of which were transferred to the Pipelines segment effective January 1, 2004. Partially offsetting these decreases was an $11 million increase in our equity earnings from an equity investment in Pakistan in 2004 when compared to 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 includes holding our general and limited partner interests in GulfTerra, a publicly traded master limited partnership, and gathering and processing assets. Following the sales of substantially all of our remaining interests in GulfTerra as well as our south Texas processing plants to Enterprise as part of a merger transaction between GulfTerra and Enterprise described further below, the majority of our gathering and processing business will be conducted through our remaining ownership interests in the merged partnership.

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. Additionally, prior to these sales, we received management fees under an agreement to provide operational and administrative services to the partnership. 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 have also agreed to provide a total of $45 million in payments to Enterprise during the three years after the merger becomes effective.

We are reimbursed for costs paid directly by us on the partnership's behalf. For the nine months ended September 30, 2004 and 2003, these reimbursements were $69 million and $68 million, of which $24 million and $22 million were incurred in the third quarter of 2004 and 2003.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	Earnings Recognized	Cash Received	Earnings Recognized	Cash Received
	(In millions)			
General partner's share of distributions	$22	$22	$64	$ 65
Proportionate share of income available to common unit holders	4	7	12	21
Series C units	4	8	14	24
Gains on issuance by GulfTerra of its common units	1	—	4	—
	$31	$37	$94	$110

For a discussion of our ownership interests in GulfTerra and our activities with the partnership, see Item 1, Financial Statements, Note 16. 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 periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
Field Services Segment Results	2004	2003	2004	2003
	(In millions, except volumes and prices)			
Processing and gathering gross margins[1]	$ 53	$ 33	$ 142	$ 109
Operating expenses	(530)	(41)	(602)	(132)
Operating loss	(477)	(8)	(460)	(23)
Other income	538	40	584	26
EBIT	$ 61	$ 32	$ 124	$ 3
Volumes and Prices:				
Processing				
Volumes (inlet BBtu/d)	3,182	3,017	3,187	3,174
Prices ($/MMBtu)	$ 0.16	$ 0.10	$ 0.14	$ 0.10
Gathering				
Volumes (BBtu/d)	223	190	220	402
Prices ($/MMBtu)	$ 0.09	$ 0.15	$ 0.10	$ 0.19

(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 and nine months ended September 30, 2004, our EBIT was $29 million and $121 million higher than the same periods in 2003. Below is a summary of significant factors affecting EBIT.

	Quarter Ended September 30,				Nine Months Ended September 30,			
	Gross Margin	Operating Expense	Other Income	EBIT Impact	Gross Margin	Operating Expense	Other Income	EBIT Impact
	Favorable (Unfavorable) (In millions)				Favorable (Unfavorable) (In millions)			
Enterprise/GulfTerra merger and related transactions	$ —	$(491)	$511	$ 20	$ —	$(491)	$511	$ 20
Other Divestitures								
Impact of reduced operations	(1)	11	—	10	(21)	39	—	18
Impairments	—	(13)	—	(13)	—	(13)	80	67
Other GulfTerra Related Items								
Minority interest	—	—	(11)	(11)	—	—	(32)	(32)
Equity earnings	—	—	(8)	(8)	—	—	(6)	(6)
Higher NGL Prices								
Processing	15	—	—	15	39	—	—	39
Javelina equity investment	—	—	5	5	—	—	13	13
Lower fuel and transportation costs	—	—	—	—	9	—	—	9
Other	6	4	1	11	6	(5)	(8)	(7)
Total	$ 20	$(489)	$498	$ 29	$ 33	$(470)	$558	$121

In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we sold substantially all of our interests in GulfTerra, as well as our processing assets in south Texas to affiliates of Enterprise. We recorded a $511 million gain on the sale of our interests in GulfTerra, an $11 million loss on the sale of our processing assets and a $480 million impairment of the goodwill associated with our Field Services segment in the third quarter of 2004. The full carrying value of the goodwill was impaired because the remaining assets in our Field Services segment could no longer support it. These transactions resulted in an overall pre-tax net gain of $20 million. For a discussion of the significant tax impacts of these transactions, see the Income Taxes section below.

In the third quarter of 2004, we incurred an impairment charge of $13 million on our Indian Springs natural gas gathering and processing assets based on anticipated losses on the sales of those assets. These assets were approved for sale by our Board of Directors in August 2004. We recorded $80 million for impairments in 2003 of equity investments in Dauphin Island and Mobile Bay based on anticipated losses on the sales of these investments, which were completed in the third quarter of 2004.

Processing margins increased primarily due to higher NGL prices relative to natural gas prices, which caused us to maximize the amount of NGLs that were extracted by our natural gas processing facilities in south Texas at an increased margin per unit. In addition, margin attributable to the marketing of NGLs increased as a result of lower fuel and transportation costs and the availability of an NGL pipeline system in 2004 to move our liquids to the Mt. Belvieu market. In the second quarter of 2003, the NGL pipeline system to Mt. Belvieu was down for maintenance.

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 periods ended September 30, 2004, EBIT in our corporate operations were higher (lower) than the same period in 2003 due to the following:

	Increase (decrease) in EBIT for quarter ended September 30, 2004 compared to 2003	Increase (decrease) in EBIT for nine months ended September 30, 2004 compared to 2003
	(In millions)	
Impairments on the assets in our telecommunications business in 2003	$ —	$ 412
Foreign currency losses on Euro-denominated debt	(13)	83
Impairments and contract terminations in our LNG business	5	90
Losses on early extinguishment of debt	—	37
Employee severance, retention and transition costs	6	35
Lease relocation charges in 2004	(29)	(30)
Other	(22)	18
Total increase (decrease) in EBIT	$ (53)	$ 645

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. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results. Additionally, as discussed in Item 1, Financial Statements, Note 5, we incurred relocation charges of approximately $29 million in the third quarter of 2004 related to the consolidation of our Houston-based operations. We estimate our total relocation charges will be approximately $100 million for the year ended December 31, 2004.

Interest and Debt Expense

Interest and debt expense for the quarter and nine months ended September 30, 2004, was $79 million and $123 million lower than the same periods in 2003. Below is an analysis of our interest expense for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions)			
Long-term debt, including current maturities	$368	$431	$1,148	$1,217
Revolving credit facilities	30	36	85	91
Other interest	8	15	25	61
Capitalized interest	(10)	(7)	(29)	(17)
Total interest and debt expense	$396	$475	$1,229	$1,352

Interest expense on long-term debt decreased due to retirements of debt during 2003 and the first nine months of 2004, net of issuances. This decrease in interest expense was partially offset by the reclassification of our preferred securities as long-term financing obligations and recording the preferred returns on these securities as interest expense. For further information of this reclassification, see the discussion below. Interest expense on our revolving credit facility decreased due to payments of $850 million on the revolver during the first and third quarters of 2004. Partially offsetting this decrease were higher commitment fees on letters of credit outstanding in the third quarter of 2004 as compared to 2003. Other interest decreased due to retirements and consolidations of other financing obligations. Finally, capitalized interest for the quarter and nine months ended September 30, 2004, was 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 nine months ended September 30, 2004 were $27 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 acquisition and consolidation of our Chaparral and Gemstone investments. Our remaining balance of preferred interests as of September 30, 2004 primarily consists of $300 million of 8.25% preferred stock of our consolidated subsidiary, El Paso Tennessee Pipeline Co.

Income Taxes

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In millions, except for rates)			
Income taxes	$ 77	$62	$ 124	$(451)
Effective tax rate	(62)%	49%	(95)%	51%

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 benefits;
- 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.

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 nine months of 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the GulfTerra transaction and impairments of certain of our foreign investments. The sale of our interests in GulfTerra associated with the merger between GulfTerra and Enterprise in September 2004 resulted in a significant taxable gain (compared to a lower book gain) and significant tax expense due to the non-deductibility of a significant portion of the goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense by approximately $139 million. See Note 16 for a further discussion of the merger and related transactions. Additionally, we received no U.S. federal income tax benefit on the impairment of certain of our foreign investments, primarily during the first quarter of 2004. The combination of these items resulted in an overall tax expense for a period in which there was a pre-tax loss.

On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not provided deferred taxes on foreign earnings because such earnings were intended to be indefinitely reinvested outside the U.S. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

In 2004, Congress proposed, but failed to enact, legislation which would disallow deductions for certain settlements made to or on behalf of governmental entities. We expect Congress to reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax assets. In such event, our tax expense would increase. Our total tax assets related to the Western Energy Settlement were approximately $400 million as of September 30, 2004.

For a further discussion of our effective tax rates, see Item 1, Financial Statements, Note 7.

Discontinued Operations

For the nine months ended September 30, 2004, the loss from our discontinued operations was $150 million compared to a loss of $1,195 million during the same period in 2003. In 2004, $78 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from losses on sales and impairment charges, and $72 million was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. The losses in 2003 related primarily to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of the decision by our Board of Directors to exit and sell these businesses and ceiling test charges related to our Canadian production operations.

Commitments and Contingencies

See Item 1, Financial Statements, Note 12, 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;
- 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 $44 million as of September 30, 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 September 30, 2004 and December 31, 2003, we had $0.7 billion and $1.7 billion of third party long-term restructured power derivative contracts. During 2004, we sold the contract held by Utility Contract Funding, which had a fair value of $865 million as of December 31, 2003. This sale and the potential 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 2004, we have been reviewing our internal controls over financial reporting as part of our compliance efforts under Section 404 of the Sarbanes-Oxley Act (SOX), as well as in connection with investigations into matters that required the restatement of our historical financial statements for the periods from 1999 to 2002 and the first nine months of 2003. Our SOX review is being performed consistent with the guidance for independent auditors established by the Public Company Accounting Oversight Board in Auditing Standard No. 2, *An Audit of Internal Control Over Financial Reporting Performed in Conjunction with an Audit of Financial Statements.* The project has entailed the 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, financial management responsible for those processes internally reviewed or "walked-through" these financial 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 involves testing the controls, including a review and inspection of the documentation supporting the operation of the controls on which we are placing reliance.

During our reviews, we identified a number of deficiencies in our internal controls over financial reporting that we determined were material weaknesses in our internal control structure. These deficiencies, which we have previously disclosed, generally involved the control environment, information system access, documentation and application of generally accepted accounting principles, and deficiencies related to segregation of duties, account reconciliations and change management over information systems. Our management, with the oversight of El Paso's Audit Committee, has devoted considerable effort to remediating the material weaknesses identified, and has made improvements in our internal controls over financial reporting to address these weaknesses. Specifically, in the quarter ending September 30, 2004, we implemented new controls to improve our account reconciliation process, improve segregation of duties and strengthen information system change management processes. We believe that we have remediated the deficiencies in internal controls related to the weaknesses previously identified. However, we continue to test to determine whether the remediated controls are operating effectively. As of December 3, 2004, we have completed approximately 78 percent of the initial testing of our internal controls over financial reporting related to our SOX review. We expect to complete this testing by early February 2005, including any retesting, to determine whether our internal controls are effective at December 31, 2004. We are also currently finalizing a framework upon which we will evaluate and classify the significance of deficiencies identified in our testing process. This is an area that involves judgment, and where interpretation and guidance continue to evolve. At this time, we have identified a number of deficiencies and areas where we can improve our internal controls. Following the completion of our testing procedures, we will assess whether there are any remaining material weaknesses, represented by either individually material deficiencies or an aggregation of significant deficiencies.

Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules. Our disclosure controls and procedures are also designed to ensure that such information is accumulated and communicated to our management to allow timely decisions regarding required disclosure. Because we have not completed the testing of many of the processes and controls intended to remediate the control deficiencies identified in our reviews of internal controls, we were unable to conclude that our disclosure controls and procedures were effective as of September 30, 2004. However, we did perform additional procedures to ensure that our disclosure controls and procedures were effective over the preparation of these financial statements.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 12, 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

Our Board of Directors, based upon a recommendation from the Governance Committee (a committee comprised of independent directors), adopted a policy on poison pills, or stockholder rights plans, and has amended our Governance Guidelines to include the following policy:

> **Policy on Poison Pill Plans**
>
> The company does not currently have in place any stockholders rights plan (also known as a "poison pill"), and the Board currently has no plans to adopt such a plan. However, if the Board is presented with a set of facts and circumstances which leads it to conclude that adopting a rights plan would be in the best interests of stockholders, the Board will seek prior stockholder approval unless the Board, in exercising its fiduciary responsibilities under the circumstances, determines by vote of a majority of the independent directors that such submission would not be in the best interests of the company's stockholders in the circumstances. If the Board were ever to adopt a rights plan without prior stockholder approval, it will be presented to the stockholders for ratification within one year or expire within one year, without being renewed or replaced. Further, if the Board adopts a rights plan and the company's stockholders do not approve such rights plan, it will terminate.

El Paso Corporation's Governance Guidelines and other information relating to our corporate governance principals, including the Board of Director's standing committee charters and El Paso Corporation's Code of Business Conduct, Restated Certificate of Incorporation and By-laws can be found on our Web site at www.elpaso.com.

2005 Annual Meeting of Stockholders

We anticipate that our 2005 annual meeting of stockholders will be held in late May 2005 and notified stockholders that proposals by stockholders that are intended for inclusion in our proxy statement and proxy to be presented at the 2005 annual meeting of stockholders must be received by Friday, January 7, 2005, in order to be considered for inclusion in the proxy materials. Such proposals should be addressed to the Corporate Secretary of El Paso and may be included in the proxy materials for the 2005 annual meeting of stockholders of El Paso if they comply with certain rules and regulations of the Securities and Exchange Commission and our By-laws governing stockholder proposals. In addition, for all other proposals to be presented at the annual meeting that are not included in the proxy statement and proxy to be timely, a stockholder's notice must be delivered to, or mailed and received at, the principal executive offices of El Paso not later than February 25, 2005. If a stockholder fails to so notify El Paso of any such proposal prior to February 25, 2005, management of El Paso Corporation will be allowed to use their discretionary voting authority with respect to proxies held by management when the proposal is raised at the annual meeting (without any discussion of the matter in its proxy statement). All proposals must be submitted and received, in writing, by the dates noted above, to David L. Siddall, Corporate Secretary, El Paso Corporation, 1001 Louisiana Street, Houston, Texas 77002, telephone (713) 420-6195 and facsimile (713) 420-4099.

Supplemental Benefits Plan

Effective December 17, 2004, an administrative amendment was made to the Plan. The American Jobs Creation Act of 2004, or the Act, which imposes certain restrictions on deferred compensation plans, such as the Plan, effective for 2005 and later years. Specific guidance regarding the terms and effect of the Act is expected from the Internal Revenue Service, but may not be published in time to amend the Plan prospectively, before the Act becomes effective. The amendment to the Plan reserves our right to make changes to the Plan, retroactively, to comply with the Act.

Officer Indemnification Agreements

On December 17, 2004, El Paso executed indemnification agreements. These agreements reiterate the rights to indemnification that are provided to certain officers under El Paso's By-laws, clarify procedures related to those rights, and provide that such rights are also available to fiduciaries under certain of El Paso's employee benefit plans. As is the case under the By-laws, the agreements provide for indemnification to the full extent permitted by Delaware law, including the right to be paid the reasonable expenses (including attorneys' fees) incurred in defending a proceeding related to service as an officer or fiduciary in advance of that proceeding's final disposition. El Paso may maintain insurance, enter into contracts, create a trust fund or use other means available to provide for indemnity payments and advances. In the event of a change in control of El Paso (as defined in the indemnification agreements), El Paso is obligated to pay the costs of independent legal counsel who will provide advice concerning the rights of each officer to indemnity payments and advances.

We are filing as an exhibit to this report the indemnification agreement for Mr. Foshee, which covers his director and officer positions and which replaces his previously filed Director Indemnification Agreement. In addition, we are filing as an exhibit to this report the form of indemnification agreement and listing of senior officers and fiduciaries who are participants in that form agreement.

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
10.PP	Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004.
10.QQ	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004).

Exhibit Number	Description
10.RR	Amended and Restated Security Agreement dated as of November 23, 2004, made by among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004).
10.SS	Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004).
10.TT	Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004).
*10.UU	Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan.
*10.VV	Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott.
*10.WW	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective December 17, 2004.
*10.XX	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004.
*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: December 17, 2004

/s/ D. DWIGHT SCOTT

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

Date: December 17, 2004

/s/ JEFFREY I. BEASON

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