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

Form 10-K/A
(Amendment No. 2)

(Mark One)

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

For the fiscal year ended December 31, 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	**76-0568816**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
El Paso Building 1001 Louisiana Street Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, par value $3 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 30, 2004 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $5,066,348,130.

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

Common Stock, par value $3 per share. Shares outstanding on March 23, 2005: 642,934,481

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

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

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

EXPLANATORY NOTE

This Amendment on Form 10-K/A constitutes Amendment No. 2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2004, which was originally filed with the Securities and Exchange Commission (SEC) on March 28, 2005 (Annual Report). Amendment No. 1 to our Annual Report was filed with the SEC on April 8, 2005.

This Amendment is being filed solely to correct a typographical error in the date of the report provided by our Independent Registered Public Accountants with respect to the financial statements included in Item 8 and to provide an updated consent of our Independent Registered Public Accountants reflecting the corrected date. It does not otherwise affect the financial statements and footnotes contained in our Annual Report, as previously amended, and does not reflect events occurring after the original filing date of March 28, 2005.

PART II

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Reports

Below is an index to the financial statements and notes contained in Item 8, Financial Statements and Supplementary Data.

EL PASO CORPORATION

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

	Year Ended December 31,		
	2004	2003 (Restated)	2002 (Restated)
Operating revenues			
Pipelines	$ 2,651	$ 2,647	$ 2,610
Production	1,735	2,141	1,931
Marketing and Trading	(508)	(635)	(1,324)
Power	795	1,176	1,672
Field Services	1,362	1,529	2,029
Corporate and eliminations	(161)	(190)	(37)
	5,874	6,668	6,881
Operating expenses			
Cost of products and services	1,363	1,818	2,468
Operation and maintenance	1,872	2,010	2,091
Depreciation, depletion and amortization	1,088	1,176	1,159
Loss on long-lived assets	1,092	860	181
Western Energy Settlement	—	104	899
Taxes, other than income taxes	253	295	254
	5,668	6,263	7,052
Operating income (loss)	206	405	(171)
Earnings (losses) from unconsolidated affiliates	559	363	(214)
Other income	189	203	197
Other expenses	(99)	(202)	(239)
Interest and debt expense	(1,607)	(1,791)	(1,297)
Distributions on preferred interests of consolidated subsidiaries	(25)	(52)	(159)
Loss before income taxes	(777)	(1,074)	(1,883)
Income taxes	25	(469)	(641)
Loss from continuing operations	(802)	(605)	(1,242)
Discontinued operations, net of income taxes	(146)	(1,314)	(425)
Cumulative effect of accounting changes, net of income taxes	—	(9)	(208)
Net loss	$ (948)	$(1,928)	$(1,875)
Basic and diluted loss per common share			
Loss from continuing operations	$ (1.25)	$ (1.01)	$ (2.22)
Discontinued operations, net of income taxes	(0.23)	(2.20)	(0.76)
Cumulative effect of accounting changes, net of income taxes	—	(0.02)	(0.37)
Net loss	$ (1.48)	$ (3.23)	$ (3.35)
Basic and diluted average common shares outstanding	639	597	560

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2004	December 31, 2003 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,117	$ 1,429
Accounts and notes receivable		
Customer, net of allowance of $199 in 2004 and $273 in 2003	1,388	2,039
Affiliates	133	189
Other	188	245
Inventory	168	181
Assets from price risk management activities	601	706
Margin and other deposits held by others	79	203
Assets held for sale and from discontinued operations	181	2,538
Restricted cash	180	590
Deferred income taxes	418	592
Other	179	210
Total current assets	5,632	8,922
Property, plant and equipment, at cost		
Pipelines	19,418	18,563
Natural gas and oil properties, at full cost	14,968	14,689
Power facilities	1,534	1,660
Gathering and processing systems	171	334
Other	882	998
	36,973	36,244
Less accumulated depreciation, depletion and amortization	18,161	18,049
Total property, plant and equipment, net	18,812	18,195
Other assets		
Investments in unconsolidated affiliates	2,614	3,409
Assets from price risk management activities	1,584	2,338
Goodwill and other intangible assets, net	428	1,082
Other	2,313	2,996
	6,939	9,825
Total assets	$31,383	$36,942

See accompanying notes.

EL PASO CORPORATION

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

	December 31, 2004	December 31, 2003 (Restated)
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,052	$ 1,552
Affiliates	21	26
Other	483	438
Short-term financing obligations, including current maturities	955	1,457
Liabilities from price risk management activities	852	734
Western Energy Settlement	44	633
Liabilities related to assets held for sale and discontinued operations	12	933
Accrued interest	333	391
Other	820	910
Total current liabilities	4,572	7,074
Long-term financing obligations, less current maturities	18,241	20,275
Other		
Liabilities from price risk management activities	1,026	781
Deferred income taxes	1,311	1,551
Western Energy Settlement	351	415
Other	2,076	2,047
	4,764	4,794
Commitments and contingencies		
Securities of subsidiaries		
Securities of consolidated subsidiaries	367	447
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 651,064,508 shares in 2004 and 639,299,156 shares in 2003	1,953	1,917
Additional paid-in capital	4,538	4,576
Accumulated deficit	(2,855)	(1,907)
Accumulated other comprehensive income	48	11
Treasury stock (at cost); 7,767,088 shares in 2004 and 7,097,326 shares in 2003	(225)	(222)
Unamortized compensation	(20)	(23)
Total stockholders' equity	3,439	4,352
Total liabilities and stockholders' equity	$31,383	$36,942

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2004	2003 (Restated) [1]	2002 (Restated) [1]
Cash flows from operating activities			
Net loss	$ (948)	$(1,928)	$(1,875)
Less loss from discontinued operations, net of income taxes	(146)	(1,314)	(425)
Net loss before discontinued operations	(802)	(614)	(1,450)
Adjustments to reconcile net loss to net cash from operating activities			
Depreciation, depletion and amortization	1,088	1,176	1,159
Western Energy Settlement	—	94	899
Deferred income tax benefit	(38)	(604)	(685)
Cumulative effect of accounting changes	—	9	208
Loss on long-lived assets	1,092	785	181
Losses (earnings) from unconsolidated affiliates, adjusted for cash distributions	(224)	(17)	521
Other non-cash income items	451	399	255
Asset and liability changes			
Accounts and notes receivable	471	2,552	(629)
Inventory	9	76	248
Change in non-hedging price risk management activities, net	191	85	1,074
Accounts payable	(295)	(2,127)	(114)
Broker and other margins on deposit with others	121	623	(257)
Broker and other margins on deposit with us	(24)	32	(647)
Western Energy Settlement liability	(626)	—	—
Other asset and liability changes			
Assets	(20)	(267)	54
Liabilities	(301)	102	(139)
Cash provided by continuing activities	1,093	2,304	678
Cash provided by (used in) discontinued activities	223	25	(242)
Net cash provided by operating activities	1,316	2,329	436
Cash flows from investing activities			
Additions to property, plant and equipment	(1,782)	(2,328)	(3,243)
Purchases of interests in equity investments	(34)	(33)	(299)
Cash paid for acquisitions, net of cash acquired	(47)	(1,078)	45
Net proceeds from the sale of assets and investments	1,927	2,458	2,779
Net change in restricted cash	578	(534)	(260)
Net change in notes receivable from affiliates	120	(43)	4
Other	(1)	—	22
Cash provided by (used in) continuing activities	761	(1,558)	(952)
Cash provided by (used in) discontinued activities	1,142	369	(303)
Net cash provided by (used in) investing activities	1,903	(1,189)	(1,255)

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

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(In millions)

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

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

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions except for per share amounts)

	For the Years Ended December 31,					
	2004		2003		2002	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	639	$ 1,917	605	$ 1,816	538	$ 1,615
Equity offering	—	—	—	—	52	155
Exchange of equity security units	—	—	15	45	—	—
Western Energy Settlement equity offerings	9	26	18	53	—	—
Other, net	3	10	1	3	15	46
Balance at end of year	651	1,953	639	1,917	605	1,816
Additional paid-in capital:						
Balance at beginning of year		4,576		4,444		3,130
Compensation related issuances		15		8		57
Tax effects of equity plans		5		(26)		15
Equity offering		—		—		846
Exchange of equity security units		—		189		—
Conversion of FELINE PRIDES[SM]		—		—		423
Western Energy Settlement equity offerings		46		67		—
Dividends ($0.16 per share)		(104)		(96)		—
Other		—		(10)		(27)
Balance at end of year		4,538		4,576		4,444
Accumulated deficit (Restated):						
Balance at beginning of year		(1,907)		21		2,387
Net loss		(948)		(1,928)		(1,875)
Dividends ($0.87 per share)		—		—		(491)
Balance at end of year		(2,855)		(1,907)		21
Accumulated other comprehensive income (loss):						
Balance at beginning of year		11		(235)		(18)
Other comprehensive income (loss)		37		246		(217)
Balance at end of year		48		11		(235)
Treasury stock, at cost:						
Balance at beginning of year	(7)	(222)	(6)	(201)	(8)	(261)
Compensation related issuances	—	9	—	—	3	79
Other	(1)	(12)	(1)	(21)	(1)	(19)
Balance at end of year	(8)	(225)	(7)	(222)	(6)	(201)
Unamortized compensation:						
Balance at beginning of year		(23)		(95)		(187)
Issuance of restricted stock		(28)		(1)		(36)
Amortization of restricted stock		23		60		73
Forfeitures of restricted stock		9		15		15
Other		(1)		(2)		40
Balance at end of year		(20)		(23)		(95)
Total stockholders' equity	643	$ 3,439	632	$ 4,352	599	$ 5,750

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2004	2003	2002 (Restated)
Net loss	$ (948)	$(1,928)	$(1,875)
Foreign currency translation adjustments (net of income tax of $10 in 2004)	7	159	(20)
Minimum pension liability accrual (net of income tax of $11 in 2004, $7 in 2003 and $20 in 2002)	(22)	11	(35)
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $8 in 2004, $50 in 2003 and $53 in 2002)	22	101	(90)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $8 in 2004, $11 in 2003 and $40 in 2002)	30	(25)	(73)
Other	—	—	1
Other comprehensive income (loss)	37	246	(217)
Comprehensive loss	$ (911)	$(1,682)	$(2,092)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

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

Restatements

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

	For the Year Ended December 31, 2002	
	As Reported	As Restated
	(In millions except per common share amounts)	
Income Statement:		
Earnings (losses) from unconsolidated affiliates	$ (226)	$ (214)
Income taxes (benefit)	(621)	(641)
Cumulative effect of accounting changes, net of income taxes	(54)	(208)
Net loss	(1,753)	(1,875)
Basic and diluted net loss per share:		
Cumulative effect of accounting changes, net of income taxes	(0.10)	(0.37)
Net loss	(3.13)	(3.35)

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

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

Income Taxes. We also identified an error in the manner in which we had originally reported certain of our income taxes associated with our discontinued Canadian exploration and production operations for the year ended December 31, 2003. We incorrectly included approximately $82 million of deferred tax benefits in continuing operations in the fourth quarter of 2003 that should have been reflected in discontinued operations. As a result, we were required to restate our 2003 financial statements, and related quarterly financial information, to reclassify this amount from continuing operations to discontinued operations. We have also reflected the restatement amounts indicated below in Notes 7 and 21. This restatement did not impact our reported net loss, balance sheet amounts or cash flows as of and for the year ended December 31, 2003. Below are the effects of this restatement on our income statement:

	For the Year Ended December 31, 2003	
	As Reported	As Restated
	(In millions except per common share amounts)	
Income taxes	$ (551)	$ (469)
Loss from continuing operations	(523)	(605)
Discontinued operations, net of income taxes	(1,396)	(1,314)
Basic and diluted loss per share:		
Loss from continuing operations	(0.87)	(1.01)
Discontinued operations, net of income taxes	(2.34)	(2.20)

Principles of Consolidation

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

Use of Estimates

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

Accounting for Regulated Operations

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

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

Cash and Cash Equivalents

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

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

Allowance for Doubtful Accounts

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

Inventory

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

Property, Plant and Equipment

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

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

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

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

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

Asset and Investment Impairments

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

Natural Gas and Oil Properties

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

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

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

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

Goodwill and Other Intangible Assets

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

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

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

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

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

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

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

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense related to these plans in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

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

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

Revenue Recognition

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

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

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

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

Power and Marketing and Trading revenues. Our Power and Marketing and Trading segments derive revenues from physical sales of natural gas and power and the management of their derivative contracts. Our derivative transactions are recorded at their fair value, and changes in their fair value are reflected in operating revenues. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities.* Revenues on physical sales are recognized at the time the commodity is delivered and are based on the volumes delivered and the contractual or market price.

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

Environmental Costs and Other Contingencies

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

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

Price Risk Management Activities

Our price risk management activities consist of the following activities:

- derivatives entered into to hedge the commodity, interest rate and foreign currency exposures primarily on our natural gas and oil production and our long-term debt;
- derivatives related to our power contract restructuring business; and
- derivatives related to our trading activities that we historically entered into with the objective of generating profits from exposure to shifts or changes in market prices.

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

Prior to 2002, we also accounted for other non-derivative contracts, such as transportation and storage capacity contracts and physical natural gas inventories and exchanges, that were used in our energy trading business at their fair values under Emerging Issues Task Force (EITF) Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. In 2002, we adopted EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involving Energy Trading and Risk Management Activities*. As a result, we adjusted the carrying value of these non-derivative instruments to zero and now account for them on an accrual basis of accounting. We also adjusted the physical natural gas inventories used in our historical trading business to their cost (which was lower than market) and our physical natural gas exchanges to their expected settlement amounts and reclassified these amounts to inventory and accounts receivable and payable on our balance sheet. Upon our adoption of EITF Issue No. 02-3, we recorded a net loss of $343 million ($222 million net of income taxes) as a cumulative effect of an accounting change in our income statement, of which $118 million was the net adjustment to our natural gas inventories and exchanges and $225 million which was the net adjustment for our other non-derivative instruments.

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

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

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

Income Taxes

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

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

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. These gains and losses were insignificant in 2004, 2003 and 2002. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component of other expense. For the years ended December 31, 2004, 2003 and 2002, we recorded net foreign currency losses of $17 million, $100 million and $91 million primarily related to currency losses on our Euro-denominated debt. The U.S. dollar is the functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and the translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholders' equity. The net cumulative currency translation gain recorded in accumulated other comprehensive income was $52 million and $45 million at December 31, 2004 and 2003. Revenues and expenses are translated at average exchange rates prevailing during the year.

Treasury Stock

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

Stock-Based Compensation

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

	Year Ended December 31,		
	2004	2003	2002 (Restated)
	(In millions, except per common share amounts)		
Net loss, as reported	$ (948)	$(1,928)	$(1,875)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	14	38	47
Deduct: Total stock-based employee compensation determined under fair value-based method for all awards, net of taxes	(35)	(88)	(169)
Pro forma net loss	$ (969)	$(1,978)	$(1,997)
Loss per share:			
Basic and diluted, as reported	$(1.48)	$ (3.23)	$ (3.35)
Basic and diluted, pro forma	$(1.52)	$ (3.31)	$ (3.57)

Accounting for Asset Retirement Obligations

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

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

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

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

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

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

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

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

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

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. On July 1, 2003, we adopted the provisions of SFAS No. 150, and reclassified $625 million of our Capital Trust I and Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement. These dividends were $40 million in both 2004 and 2003. These dividends were recorded in interest and debt expense in 2004, and $20 million of our 2003 dividends were recorded in interest expense and $20 million were recorded as distributions on preferred interests in our income statement in 2003.

New Accounting Pronouncements Issued But Not Yet Adopted

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

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

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

2. Acquisitions and Consolidations

Acquisitions

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

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

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

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

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

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

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

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

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

Gemstone. We entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. Gemstone had investments in three power projects (Macae, Porto Velho and Araucaria) and also owned a preferred interest in two of our consolidated power projects, Rio Negro and Manaus. In 2003, we acquired the third-party investor's (Rabobank) interest in Gemstone for approximately $50 million. Gemstone's results of operations have been included in our consolidated financial statements since April 1, 2003. Had we acquired Gemstone effective January 1, 2003, our net income and basic and diluted earnings per share for the year ended December 31, 2003 would not have been affected, but our revenues and operating income would have been higher by $58 million and $41 million (amounts unaudited). Had the acquisition been effective January 1, 2002, our 2002 net income and our basic and diluted earnings per share would not have been affected, but our revenues and operating income would have been higher by $187 million and $134 million (amounts unaudited).

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

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

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

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

Consolidations

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

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

	Increase/(Decrease) (In millions)
Restricted cash	$ 34
Accounts and notes receivable from affiliates	(54)
Investments in unconsolidated affiliates	(5)
Property, plant, and equipment, net	37
Other current and non-current assets	(15)
Long-term financing obligations	15
Other current and non-current liabilities	(4)
Minority interest of consolidated subsidiaries	(14)

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

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

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

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

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

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

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

Lakeside. In 2003, we amended an operating lease agreement at our Lakeside Technology Center to add a guarantee benefiting the party who had invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under our previous $3 billion revolving credit facility. This guarantee reduced the investor's risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor. The consolidation of Lakeside Technology Center resulted in an increase in our property, plant and equipment of approximately $275 million and an increase in our long-term debt of approximately $275 million. In 2004, we repaid the $275 million that was scheduled to mature in 2006. Additionally, upon its consolidation, we recorded an asset impairment charge of approximately $127 million representing the difference between the facility's estimated fair value and the residual value guarantee under the lease. Prior to its consolidation, this difference was being periodically expensed as part of operating lease expense over the term of the lease.

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

3. Divestitures

Sales of Assets and Investments

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

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

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

The following table summarizes the significant assets sold:

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

See Note 5 for a discussion of gains, losses and asset impairments related to the sales above.

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

- Remaining 9.9% membership interest in the general partner of Enterprise and approximately 13.5 million units in Enterprise for $425 million;
- Interests in Cedar Brakes I and II for $94 million;
- Interest in a paraxylene plant for $74 million;
- Interest in a natural gas gathering system and processing facility for $75 million;
- Pipeline facilities for $31 million;
- Interest in an Indian power plant for $20 million;
- MTBE processing facility for $5 million;
- Eagle Point power facility for $3 million; and
- Interest in the Rensselaer power facility and its obligations.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. These assets consist of certain of our domestic power plants and natural gas gathering and processing assets in our Field Services segment. As of December 31, 2004, we had assets held for sale of $75 million related to our Indian Springs natural gas gathering and processing facility, which was sold in January 2005, and four domestic power assets, which were impaired in previous years and which we expect to sell within the next twelve months. The following table details the items which are reflected as current assets and liabilities held for sale in our balance sheet as of December 31, 2003 (in millions).

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

Discontinued Operations

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During 2004, we recognized approximately $99 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties by mid-2005.

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

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

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

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

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
	(In millions)			
Operating Results Data				
Year Ended December 31, 2004				
Revenues	$ 787	$ 31	$ —	$ 818
Costs and expenses	(839)	(53)	—	(892)
Loss on long-lived assets	(36)	(99)	—	(135)
Other income	23	—	—	23
Interest and debt expense	(3)	1	—	(2)
Loss before income taxes	(68)	(120)	—	(188)
Income taxes	2	(44)	—	(42)
Loss from discontinued operations, net of income taxes	$ (70)	$ (76)	$ —	$ (146)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
		(In millions)		
Year Ended December 31, 2003 (Restated)				
Revenues	$ 5,652	$ 88	$ 27	$ 5,767
Costs and expenses	(5,793)	(129)	(13)	(5,935)
Loss on long-lived assets	(1,404)	(89)	(9)	(1,502)
Other income	(10)	—	1	(9)
Interest and debt expense	(11)	4	—	(7)
Gain (loss) before income taxes	(1,566)	(126)	6	(1,686)
Income taxes	(262)	(115)	5	(372)
Gain (loss) from discontinued operations, net of income taxes	$(1,304)	$ (11)	$ 1	$(1,314)
Year Ended December 31, 2002				
Revenues	$ 4,788	$ 71	$ 309	$ 5,168
Costs and expenses	(4,916)	(172)	(327)	(5,415)
Loss on long-lived assets	(97)	(4)	(184)	(285)
Other income	20	—	5	25
Interest and debt expense	(12)	4	—	(8)
Loss before income taxes	(217)	(101)	(197)	(515)
Income taxes	16	(33)	(73)	(90)
Loss from discontinued operations, net of income taxes	$ (233)	$ (68)	$(124)	$ (425)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Financial Position Data			
December 31, 2004			
Assets of discontinued operations			
Accounts and notes receivable	$ 39	$ 2	$ 41
Inventory	8	—	8
Other current assets	3	1	4
Property, plant and equipment, net	14	6	20
Other non-current assets	33	—	33
Total assets	$ 97	$ 9	$ 106
Liabilities of discontinued operations			
Accounts payable	$ 5	$ 1	$ 6
Other current liabilities	3	—	3
Other non-current liabilities	3	—	3
Total liabilities	$ 11	$ 1	$ 12

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

4. Restructuring Costs

As a result of actions taken in 2002, 2003, and 2004, we incurred certain organizational restructuring costs included in operation and maintenance expense. On January 1, 2003, we adopted the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, and recognized restructuring costs applying the provisions of that standard. Prior to this date, we had recognized restructuring costs according to the provisions of EITF Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity*. By segment, our restructuring costs for the years ended December 31, were as follows:

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

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

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

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

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

5. Loss on Long-Lived Assets

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

	2004	2003	2002 (Restated)
		(In millions)	
Net realized (gain) loss	$ (16)	$ 69	$(259)
Asset impairments			
Power			
Domestic assets and restructured power contract entities	397	147	—
International assets	197	—	—
Turbines	1	33	162
Field Services			
South Texas processing assets	—	167	—
North Louisiana gathering facility	—	—	66
Indian Springs processing assets	13	—	—
Goodwill impairment	480	—	—
Other	11	4	—
Production			
Other	8	10	—
Corporate			
Telecommunications assets	—	396	168
Other	1	34	44
Total asset impairments	1,108	791	440
Loss on long-lived assets	1,092	860	181
(Gain) loss on investments in unconsolidated affiliates[1]	(129)	176	612
(Gain) loss on assets and investments	$ 963	$1,036	$ 793

[1] See Note 22 for a further description of these gains and losses.

Net Realized (Gain) Loss

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

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

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

Asset Impairments

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

Our 2004 Power segment charges include a $227 million impairment on the sale of our domestic equity interests in Cedar Brakes I and II, which closed in the first quarter of 2005, a $167 million impairment of our Manaus and Rio Negro power facilities in Brazil as a result of renegotiating and extending their power purchase agreements, and a $30 million impairment on our consolidated Asian assets in connection with our decision to sell these assets. In addition, in 2004, we impaired UCF prior to its sale by $98 million and recorded impairments of $73 million related to the sales of various other power assets and turbines. Our 2003 and 2002 Power segment impairment charges were primarily a result of our planned sale of domestic power assets (including our turbines classified in long-term assets).

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

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

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 3 and 22. For additional discussion on goodwill and other intangibles, see Note 1.

6. Other Income and Other Expenses

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

	2004	2003	2002
		(In millions)	
Other Income			
Interest income	$ 93	$ 83	$ 84
Allowance for funds used during construction	23	19	7
Development, management and administrative services fees on power projects from affiliates	21	18	21
Re-application of SFAS No. 71 (CIG and WIC)	—	18	—
Net foreign currency gain	9	12	—
Favorable resolution of non-operating contingent obligations	—	9	38
Gain on early extinguishment of debt	—	—	21
Other	43	44	26
Total	$189	$203	$197

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

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

7. Income Taxes

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

	2004	2003	2002 (Restated)
		(In millions)	
U.S.	$(698)	$(1,330)	$(2,282)
Foreign	(79)	256	399
	$(777)	$(1,074)	$(1,883)

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

	2004	2003 (Restated)	2002 (Restated)
		(In millions)	
Current			
Federal	$ (15)	$ 36	$ (15)
State	39	58	27
Foreign	39	41	32
	63	135	44
Deferred			
Federal	(63)	(556)	(679)
State	(5)	(55)	(11)
Foreign	30	7	5
	(38)	(604)	(685)
Total income taxes	$ 25	$(469)	$(641)

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

	2004	2003 (Restated)	2002 (Restated)
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$(272)	$(376)	$(659)
Increase (decrease)			
Abandonments and sales of foreign investments	(4)	(43)	—
Valuation allowances	18	(57)	44
Foreign income taxed at different rates	155	(21)	6
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(18)	(13)	(18)
Non-deductible dividends on preferred stock of subsidiaries	9	10	10
State income taxes, net of federal income tax effect	5	5	2
Non-conventional fuel tax credits	—	—	(11)
Non-deductible goodwill impairments	139	29	—
Other	(7)	(3)	(15)
Income taxes	$ 25	$(469)	$(641)
Effective tax rate	(3)%	44%	34%

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

	2004	2003 (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$2,590	$2,147
Investments in unconsolidated affiliates	410	757
Employee benefits and deferred compensation	93	126
Price risk management activities	71	—
Regulatory and other assets	163	193
Total deferred tax liability	3,327	3,223
Deferred tax assets		
Net operating loss and tax credit carryovers		
U.S. federal	1,196	814
State	174	146
Foreign	35	18
Western Energy Settlement	144	400
Environmental liability	174	206
Price risk management activities	—	136
Debt	79	105
Inventory	85	91
Deferred federal tax on deferred state income tax liability	59	75
Allowance for doubtful accounts	99	75
Lease liabilities	53	—
Other	387	276
Valuation allowance	(51)	(9)
Total deferred tax asset	2,434	2,333
Net deferred tax liability	$ 893	$ 890

In 2004, Congress proposed but failed to enact legislation which would disallow deductions for certain settlements made to or on behalf of governmental entities. It is possible Congress will reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy

Settlement and could result in a write-off of some or all of the associated tax benefits. In such event, our tax expense would increase. Our total tax benefits related to the Western Energy Settlement were approximately $400 million as of December 31, 2004.

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

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. At December 31, 2004, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $551 million. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income other than $4 million included in the deferred tax liability we recorded related to our investment in our Asian power projects.

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

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

	Carryover Period				
	2005	2006-2010	2011-2015	2016-2024	Total
			(In millions)		
U.S. federal net operating loss	$—	$ 7	$ —	$3,118	$3,125
State net operating loss	8	849	412	987	2,256

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

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

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

8. Earnings Per Share

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

9. Fair Value of Financial Instruments

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

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

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

10. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2004 and 2003. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production as well as instruments to hedge our interest rate and currency risks on long-term debt. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities.

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

(1) In December 2004, we designated other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004.

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

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

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

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

The above valuation techniques are used for valuing derivative contracts that have historically been accounted for as trading activities, as well as for those that are used to hedge our natural gas and oil production. We have adjusted this method to determine the fair value of our restructured power contracts. Our restructured power derivatives use the same methodology discussed above for determining the forward settlement prices but are discounted using a risk free interest rate, adjusted for the individual credit spread for each counterparty to the contract. Additionally, no liquidity valuation adjustment is provided on these derivative contracts since they are intended to be held through maturity.

Derivatives Designated as Hedges

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

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

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

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

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

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

(1) Reclassifications occur upon the physical delivery of the hedged commodity and the corresponding expiration of the hedge or if the forecasted transaction is no longer probable.
(2) Substantially all of these amounts were reclassified into income with the repurchase of approximately €528 million of debt in March 2005.
(3) In December 2002, we removed the hedging designation on these derivatives related to our Euro-denominated debt.
(4) Accumulated other comprehensive income (loss) also includes $52 million and $45 million of net cumulative currency translation adjustments and $(46) million and $(24) million of additional minimum pension liability as of December 31, 2004 and 2003. All amounts are net of taxes.

In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges, specifically cash flow hedges, beginning in the fourth quarter of 2004.

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

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

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

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

Power Contract Restructuring Activities

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

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

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

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

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

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

As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and are actively seeking to sell or otherwise dispose of our existing restructured power contracts. In 2004, we completed the sales of UCF (which is the restructured Eagle Point power contract) and Mohawk River Funding IV. (See Note 3 for a discussion of these sales.) Mohawk River Funding, III ("MRF III") had a prior purchase agreement ("USGen PPA") with USGen New England, Inc. ("USGen"). USGen filed for Chapter 11 bankruptcy protection and the USGen PPA was terminated automatically as a result of the bankruptcy filing. MRF III filed a proof of claim in the bankruptcy case and the bankruptcy court issued an order resolving the claim. The order is not final at this time and may be subject to change which could result in a final award that is either more or less than the receivable that has been recorded. Additionally, in March 2005, we completed the sale of Cedar Brakes I and II and the related restructured derivative power contracts.

Other Commodity-Based Derivatives

Our other commodity-based derivatives primarily relate to our historical trading activities, which include the services we provide in the energy sector that we entered into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities. Our derivatives in our trading portfolio had a fair value liability of $61 million and $488 million as of December 31, 2004 and 2003. In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004.

Credit Risk

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

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

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

Counterparty	Net Financial Instrument Asset Exposure — Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2004				
Energy marketers	$ 440	$ 44	$ 35	$ 519
Natural gas and electric utilities	424	—	91	515
Other	245	—	7	252
Net financial instrument assets[2]	1,109	44	133	1,286
Collateral held by us	(349)	(39)	(81)	(469)
Net exposure from financial instrument assets	$ 760	$ 5	$ 52	$ 817
December 31, 2003				
Energy marketers	$ 425	$ 43	$ 53	$ 521
Natural gas and electric utilities	1,755	—	78	1,833
Other	106	1	75	182
Net financial instrument assets[2]	2,286	44	206	2,536
Collateral held by us	(132)	(10)	(83)	(225)
Net exposure from financial instrument assets	$2,154	$ 34	$123	$2,311

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

(2) Net asset exposure from financial instrument assets primarily relates to our assets and liabilities from price risk management activities. These exposures have been prepared by netting assets against liabilities on counterparties where we have a contractual right to offset. The positions netted include both current and non-current amounts and do not include amounts already billed or delivered under the derivative contracts, which would be netted against these exposures.

We have approximately 125 counterparties, most of which are energy marketers. Although most of our counterparties are not currently rated as below investment grade, if one of our counterparties fails to perform, such as in the case of Enron (see Note 17 for a further discussion of the Enron Bankruptcy), we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and quantities cannot be established.

One electric utility customer, Public Service Electric and Gas Company (PSEG), comprised 42 percent and 66 percent of our net financial instrument asset exposure as of December 31, 2004 and 2003. Our net financial instrument asset exposure to PSEG was eliminated with the sale of our interests in Cedar Brakes I and II in the first quarter of 2005. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

11. Inventory

We have the following current inventory as of December 31:

	2004	2003
	(In millions)	
Materials and supplies and other	$130	$145
NGL and natural gas in storage	38	36
Total current inventory	$168	$181

We also have the following non-current inventory that is included in other assets in our balance sheets as of December 31:

	2004	2003
	(In millions)	
Dark fiber	$ —	$ 5
Turbines	76	98
Total non-current inventory	$ 76	$103

12. Regulatory Assets and Liabilities

Our regulatory assets and liabilities are included in other current and non-current assets and liabilities in our balance sheets. These balances are presented in our balance sheets on a gross basis. Below are the details of our regulatory assets and liabilities for our regulated interstate systems that apply the provisions of SFAS No. 71 as of December 31, which are recoverable over various periods:

Description	2004	2003
	(In millions)	
Current regulatory assets[(1)]	$ 3	$ 2
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction[(1)]	85	77
Postretirement benefits[(1)]	30	32
Unamortized net loss on reacquired debt[(1)]	23	26
Under-collected state income tax[(1)]	7	4
Other[(1)]	10	4
Total non-current regulatory assets	155	143
Total regulatory assets	$158	$145
Current regulatory liabilities		
Cashout imbalance settlement[(1)]	$ 9	$ 9
Other	—	2
	9	11

Description	2004	2003
	(In millions)	
Non-current regulatory liabilities		
Environmental liability[1]	97	87
Cost of removal of offshore assets	50	51
Property and plant depreciation	35	28
Postretirement benefits[1]	13	11
Plant regulatory liability[1]	11	11
Excess deferred income taxes	11	10
Other	11	5
Total non-current regulatory liabilities	228	203
Total regulatory liabilities	$237	$214

[1] Some of these amounts are not included in our rate base on which we earn a current return.

13. Other Assets and Liabilities

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

	2004	2003
	(In millions)	
Other current assets		
Prepaid expenses	$ 132	$ 146
Other	47	64
Total	$ 179	$ 210
Other non-current assets		
Pension assets (Note 18)	$ 933	$ 962
Notes receivable from affiliates	287	349
Restricted cash (Note 1)	180	349
Unamortized debt expenses	192	246
Regulatory assets (Note 12)	155	143
Long-term receivables	343	108
Notes receivable	46	113
Turbine inventory (Note 11)	76	98
Other investments	48	60
Assets of discontinued operations	—	405
Other	53	163
Total	$2,313	$2,996

	2004	2003
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 136	$ 156
Broker margin and other amounts on deposit with us	131	155
Income taxes	80	132
Environmental, legal and rate reserves (Note 17)	84	96
Deposits	39	67
Obligations under swap agreement (Note 15)	—	49
Other postretirement benefits (Note 18)	38	45
Asset retirement obligations (Note 1)	28	26
Dividends payable	25	23
Accrued liabilities	74	49
Other	185	112
Total	$ 820	$ 910
Other non-current liabilities		
Environmental and legal reserves (Note 17)	$ 763	$ 450
Other postretirement and employment benefits (Note 18)	248	272
Obligations under swap agreement (Note 15)	—	208
Regulatory liabilities (Note 12)	228	203
Asset retirement obligations (Note 1)	244	192
Other deferred credits	126	157
Accrued lease obligations	157	106
Insurance reserves	125	136
Deferred gain on sale of assets to GulfTerra (Note 17)	15	101
Deferred compensation	56	60
Pipeline integrity liability (Note 22)	50	69
Liabilities of discontinued operations	—	3
Other	64	90
Total	$2,076	$2,047

14. Property, Plant and Equipment

At December 31, 2004 and 2003, we had approximately $0.8 billion and $1.0 billion of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2004 and 2003, TGP, EPNG and ANR have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $5 billion and accumulated depreciation was approximately $1.3 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during the three years ended December 31, 2004, 2003, and 2002 was approximately $76 million, $74 million and $71 million. The adoption of SFAS No. 142 did not impact these amounts since they were included as part of our property, plant and equipment, rather than as goodwill. We do not currently earn a return on these excess purchase costs from our rate payers.

15. Debt, Other Financing Obligations and Other Credit Facilities

	2004	2003
	(In millions)	
Short-term financing obligations, including current maturities	$ 955	$ 1,457
Long-term financing obligations	18,241	20,275
Total	$19,196	$21,732

Our debt and other credit facilities consist of both short and long-term borrowings with third parties and notes with our affiliated companies. During 2004, we entered into a new $3 billion credit agreement and sold entities with debt obligations. A summary of our actions is as follows (in millions):

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

(1) Includes proceeds from a $1.25 billion term loan under our new $3 billion credit agreement.
(2) Includes $850 million of repayments under our previous revolving credit facility.
(3) Consists of $815 million of debt related to Utility Contract Funding, L.L.C. and $72 million of debt related to Mohawk River Funding IV.

Short-Term Financing Obligations

We had the following short-term borrowings and other financing obligations as of December 31:

	2004	2003
	(In millions)	
Current maturities of long-term debt and other financing obligations	$948	$1,449
Short-term financing obligation	7	8
	$955	$1,457

Long-Term Financing Obligations

Our long-term financing obligations outstanding consisted of the following as of December 31:

	2004	2003
	(In millions)	
Long-term debt		
ANR Pipeline Company		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	$ 800	$ 800
Notes, 13.75% due 2010	12	13
Colorado Interstate Gas Company		
Debentures, 6.85% through 10.0%, due 2005 and 2037	280	280
El Paso CGP Company		
Senior notes, 6.2% through 7.75%, due 2004 through 2010	930	1,305
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,357	1,395
El Paso Corporation		
Senior notes, 5.75% through 7.125%, due 2006 through 2009	1,956	1,817
Equity security units, 6.14% due 2007	272	272
Notes, 6.625% through 7.875%, due 2005 through 2018	1,952	2,002
Medium-term notes, 6.95% through 9.25%, due 2004 through 2032	2,784	2,812
Zero coupon convertible debentures due 2021	822	895
$3 billion revolver, LIBOR plus 3.5% due June 2005	—	850
$1.25 billion term loan, LIBOR plus 2.75% due 2009	1,245	—
El Paso Natural Gas Company		
Notes, 7.625% and 8.375%, due 2010 and 2032	655	655
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
El Paso Production Holding Company		
Senior notes, 7.75%, due 2013	1,200	1,200

	2004	2003
	(In millions)	
Power		
Non-recourse senior notes, 7.75% through 9.875%, due 2008 through 2014	666	770
Non-recourse notes, variable rates, due 2007 and 2008	320	361
Recourse notes, 7.27% and 8.5%, due 2005 and 2016	40	85
Gemstone notes, 7.71% due 2004	—	950
Non-recourse financing—UCF, 7.944%, due 2016	—	829
Southern Natural Gas Company		
Notes and senior notes, 6.125% through 8.875%, due 2007 through 2032	1,200	1,200
Tennessee Gas Pipeline Company		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
Notes, 8.375%, due 2032	240	240
Other	137	404
	18,714	20,981
Other financing obligations		
Capital Trust I	325	325
Coastal Finance I	300	300
Lakeside Technology Center lease financing loan due 2006	—	275
	625	900
Subtotal	19,339	21,881
Less:		
Unamortized discount and premium on long-term debt	150	157
Current maturities	948	1,449
Total long-term financing obligations, less current maturities	$18,241	$20,275

During 2004 and to date in 2005, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Principal (In millions)	Due Date
Issuances and other increases				
Macae	Non-recourse note	LIBOR + 4.25%	$ 50	2007
Blue Lake Gas Storage[(1)]	Non-recourse term loan	LIBOR + 1.2%	14	2006
El Paso[(2)]	Notes	6.50%	213	2005
El Paso[(3)]	Term loan	LIBOR + 2.75%	1,250	2009
Increases through December 31, 2004			$1,527	
Colorado Interstate Gas Company	Senior Notes	5.95%	200	2015
Increases through March 25, 2005			$1,727	
Repayments, repurchases and other retirements				
El Paso CGP	Note	LIBOR + 3.5%	$ 200	
El Paso	Revolver	LIBOR + 3.5%	850	
El Paso CGP	Note	6.2%	190	
Mohawk River Funding IV[(4)]	Non-recourse note	7.75%	72	
Utility Contract Funding[(4)]	Non-recourse senior notes	7.944%	815	
Gemstone	Notes	7.71%	950	
Lakeside	Note	LIBOR + 3.5%	275	
El Paso CGP	Senior Debentures	10.25%	38	
El Paso[(2)]	Notes	6.50%	213	
El Paso[(5)]	Zero coupon debenture	—	109	
El Paso	Notes	Various	49	
El Paso CGP	Notes	Various	185	
El Paso	Medium-term notes	Various	28	
Other	Long-term debt	Various	283	
Decreases through December 31, 2004			4,257	
El Paso[(5)]	Zero coupon debenture	—	185	
Cedar Brakes I[(4)]	Non-recourse notes	8.5%	286	
Cedar Brakes II[(4)]	Non-recourse notes	9.88%	380	
El Paso[(6)]	Euros	5.75%	715	
Other	Long-term debt	Various	96	
Decreases through March 25, 2005			$5,919	

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

(2) In the fourth quarter of 2004, we entered into an agreement with Enron that liquidated two derivative swap agreements of approximately $221 million in exchange for approximately $213 million of 6.5% one year notes. Subsequent to the closing of our new credit agreement, these notes were paid in full.

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

(4) The remaining balance of these debt obligations was eliminated when we sold our interests in Mohawk River Funding IV, UCF and Cedar Brakes I and II.

(5) In December 2004 and January 2005, we repurchased these 4% yield-to-maturity zero-coupon debentures. The amount shown as principal is the carrying value on the date the debt was retired as compared to its maturity value in 2021 of $206 million in December 2004, and $351 million in January 2005.

(6) In March 2005, we repaid debt with a principal balance of €528 million, which had a carrying value of $724 million in long-term debt on our balance sheet as of December 31, 2004. In conjunction with this repayment, we also terminated derivative contracts with a fair value of $152 million as of December 31, 2004 that hedged this debt. The total net payment was $579 million. See Note 10 for additional information on the repurchase of the derivative contracts.

Aggregate maturities of the principal amounts of long-term financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2005	$ 948
2006[1]	1,155
2007	835
2008	733
2009	2,637
Thereafter	13,031
Total long-term financing obligations, including current maturities	$19,339

[1] Excludes $0.8 billion of zero coupon debentures as discussed below.

Included above in 2005 is $320 million of debt associated with our Macae project in Brazil, as a result of an event of default on Macae's non-recourse debt. (See Note 17 for additional details on the event of default.) Also included in 2005 are approximately $114 million of notes and debentures that holders have the option to redeem in 2005, prior to their stated maturities. Of this amount, $75 million is eligible for redemption solely in 2005 and, if not redeemed, will be reclassified to long-term debt in 2006.

Included in the "thereafter" line of the table above are $600 million of other debentures that holders have an option to redeem in 2007 prior to their stated maturities and $822 million of zero coupon convertible debentures. The zero-coupon debentures have a maturity value of $1.6 billion, are due 2021 and have a yield to maturity of 4 percent. The holders can cause us to repurchase these debentures at their option in years 2006, 2011 and 2016, should they make this election, we can choose to settle in cash or common stock at a price which approximates market. These debentures are convertible into 7,468,726 shares of our common stock, which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate is equal to a conversion price of $94.604 per share of our common stock.

Credit Facilities

In November 2004, we replaced our previous $3 billion revolving credit facility, which was scheduled to mature in June 2005, with a new $3 billion credit agreement with a group of lenders. This $3 billion credit agreement consists of a $1.25 billion five-year term loan; a $1 billion three-year revolving credit facility; and a $750 million, five-year letter of credit facility. Certain of our subsidiaries, EPNG, TGP, ANR and CIG, also continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement, which is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company and Southern Gas Storage Company.

As of December 31, 2004, we had $1.25 billion outstanding under the term loan and had utilized approximately all of the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to issue letters of credit. The term loan accrues interest at LIBOR plus 2.75 percent, matures in November 2009, and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the new revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. The terms of the new $750 million letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity under the letter of credit facility as revolving loans with a maturity in November 2009. We pay LIBOR plus 2.75 percent on any amounts borrowed under the letter of credit facility, and 2.85 percent on letters of credit and unborrowed funds.

Restrictive Covenants

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

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

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

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

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

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

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

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

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $850 million. If breached, the amounts guaranteed by its guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of such subsidiaries in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

Other Financing Arrangements

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I, a wholly owned subsidiary, which issued 6.5 million of 4.75 percent trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued due 2028, their sole asset. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay the obligations on Trust I's preferred securities. We provide a full and unconditional guarantee of Trust I's preferred securities.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 percent, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I preferred security (equivalent to a conversion price of $41.59 per common share). During 2003, the outstanding amounts of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Coastal Finance I. Coastal Finance I is an indirect wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I holds subordinated debt securities issued by our wholly owned subsidiary, El Paso CGP, that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375 percent of the liquidation amount of $25 per preferred security. Coastal Finance I's only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I's preferred securities. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. El Paso CGP provides a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available. We have no obligation to provide funds to Coastal Finance I for the payment of or redemption of the preferred securities outside of our obligation to pay interest and principal on the subordinated debt securities. During 2003, the amounts outstanding of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Equity Security Units. In June 2002, we issued 11.5 million, 9 percent equity security units. Equity security units consist of two securities: i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86 percent and that requires its holder to buy our common stock on a stated settlement date of August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14 percent. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders' obligation to purchase shares of our common stock under the purchase contracts. In December 2003, we completed a tender offer to exchange 6,057,953 of the outstanding equity security units, which represented approximately 53 percent of the total units outstanding. In the exchange, we issued a total of 15,182,972 shares of our common stock that had a total market value of $119 million, and paid $59 million in cash.

When the remaining purchase contracts are settled in 2005, the contract provides for us to issue common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 11 million shares and up to a maximum of approximately 14 million shares on the settlement date, depending on our average stock price.

Non-Recourse Project Financings. Many of our power subsidiaries and investments have borrowed a material portion of the costs to acquire or construct their domestic and international power assets. Such borrowings are made with recourse only to the project company and assets (i.e. without recourse to El Paso). On occasion, events have occurred in connection with several of our projects that have either constituted an event of default under the loan agreements or could constitute an event of default upon delivery of a notice from the lenders and the failure of the subsidiary or investee to cure the event during an applicable grace period. Currently, we have one consolidated subsidiary, Macae, where the power off taker to the project, Petrobras, has not paid all amounts owed under its contract with the plant. This non-payment has created an event of default on that project under its loan agreements. Accordingly, we classified approximately $320 million as current debt as of December 31, 2004. (See Note 17 for additional information on our investment in Macae.) In addition, we have several other projects that we account for as equity investments that are in default under their loan agreements, including Saba, Berkshire and East Asia Power. We have written off all of our investment in both the Berkshire and East Asia Power facilities and have a $9 million interest in Saba. There is no recourse to El Paso under the loans at these investments. In addition, we have had events of default or other events that could lead to an event of default upon notice from the lenders on other projects, but we do not believe any of these defaults will have a material impact on our or our subsidiaries' financial statements.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2004, we had outstanding letters of credit of approximately $1.3 billion, of which $107 million was supported with cash collateral, and $1.2 billion were issued under our credit agreement. Included in this amount were $0.9 billion of letters of credit securing our recorded obligations related to price risk management activities.

Available Capacity Under Shelf Registration Statements

We maintain a shelf registration statement with the SEC that allows us to issue a combination of debt, equity and other instruments, including trust preferred securities of two wholly owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we would be required to issue full and unconditional guarantees on these securities. As of December 31, 2004, we had $926 million remaining capacity under this shelf registration statement; however, we are unable to access this capacity until January 2006, due to the untimely filing of our 2003 annual and quarterly 2004 financial statements.

16. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into financing transactions that have been accomplished through the sale of preferred interests in consolidated subsidiaries. During 2003, we repaid approximately $2 billion of these preferred interests, reclassified $625 million to long-term financing obligations as a result of adopting SFAS No. 150 (see Note 1) and eliminated $300 million in consolidation because we acquired the holder of those preferred interests. Our remaining preferred interest is discussed below.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co. (EPTP) issued 6 million shares of publicly registered 8.25 percent cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at our option, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time. EPTP indirectly owns our marketing and trading businesses, substantially all of our domestic and international power businesses, and TGP. While not required, the following financial information is intended to provide additional information of EPTP to its preferred security holders:

	Year Ended December 31,		
	2004	2003	2002
		(In millions) (unaudited)	
Operating results data:			
Operating revenues	$ 812	$1,459	$ 1,132
Operating expenses	1,131	1,865	2,268
Loss from continuing operations	(399)	(377)	(1,288)
Net loss	(399)	(377)	(1,510)

	December 31, 2004	December 31, 2003
	(In millions) (unaudited)	
Financial position data:		
Current assets	$2,783	$ 4,217
Non-current assets	9,001	9,892
Short-term debt	402	1,111
Other current liabilities	4,693	5,409
Long-term debt	2,183	2,545
Other non-current liabilities	2,580	2,642
Securities of subsidiaries	3	28
Equity in net assets	1,923	2,374

17. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2004, our master settlement agreement, along with other separate settlement agreements, became effective with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada. This resolves the principal litigation, investigations, claims and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western U.S. (the Western Energy Settlement). As part of the Western Energy Settlement, we admitted no wrongdoing but agreed, among other things, to make various cash payments and modify an existing power supply contract. We also entered into a Joint Settlement Agreement or JSA where we agreed, subject to the limitations in the JSA, to (1) make 3.29 Bcf/d of capacity available to California to the extent shippers sign firm contracts for that capacity, (2) maintain facilities sufficient to physically deliver 3.29 Bcf/d to California; (3) construct facilities which we completed in 2004, (4) clarify certain shippers' recall rights on the system and (5) bar any of our affiliated companies from obtaining additional firm capacity on our EPNG pipeline system during a five year period from the effective date of the settlement.

In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA described above with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia, where this matter is pending. We expect this appeal to be fully briefed by the summer of 2005.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. During 2003, we recorded additional pretax charges of $104 million based upon reaching definitive settlement agreements. Charges and expenses associated with the Western Energy Settlement are included in operations and maintenance expense in our consolidated statements of income. When the settlement became effective in June 2004, $602 million was released to the settling parties. This amount is shown as a reduction of our cash flows from operations in the second quarter of 2004. Of the amount released, $568 million had been previously held in an escrow account pending final approval of the settlement. The release of these restricted funds is included as an increase in our cash flows from investing activities. Our remaining obligation as of December 31, 2004 under the Western Energy Settlement consists of a discounted 20-year cash payment obligation of $395 million and a price reduction under a power supply contract, which is included in our price risk management activities. In connection with the Western Energy Settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining cash payment obligation. The collateral requirement is being reduced as payments under the 20 year obligation are made. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 7.

Shareholder/Derivative/ERISA Litigation

Shareholder Litigation. Since 2002, twenty-nine purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our current and former officers and directors. One of these lawsuits has been dismissed and the remaining 28 lawsuits have been consolidated in federal court in Houston, Texas. The consolidated lawsuit generally challenges the accuracy or completeness of press releases and other public statements made during the class period from 2001 through early 2004, related to wash trades, mark-to-market accounting, off-balance sheet debt, overstatement of oil and gas reserves and manipulation of the California energy market. The consolidated lawsuit is currently stayed.

Derivative Litigation. Since 2002, five shareholder derivative actions have also been filed. Three of the actions allege the same claims as in the consolidated shareholder class action suit described above, with one of the actions including a claim for compensation disgorgement against certain individuals. These actions are currently stayed. Two actions are now consolidated in state court in Houston, Texas and generally allege that manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value.

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

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

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

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

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. In January 2005 a purported class action lawsuit styled *Leggett et al. v Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of the all residential and commercial purchasers of natural gas in the state of Tennessee during the past three years. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. The Company has also had similar claims asserted by individual commercial customers. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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

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

Bank of America. We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs seek an accounting and damages for alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in

Oklahoma, plus interest from the time such amounts were allegedly due, as well as punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties have completed discovery. The plaintiffs have filed expert reports alleging damages in excess of $1 billion. Pursuant to a recent summary judgment decision, the court ruled that claims previously released by the settlement of *Altheide v. Meridian,* a nation-wide royalty class action against Burlington and its affiliates are barred from being reasserted in this action. We believe that this ruling eliminates a material, but yet unquantified portion of the alleged class damages. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Resources, Inc., and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity by Burlington. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $186 million at December 31, 2004. We have political risk insurance that covers a portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil with property, plant and equipment having a net book value of $700 million as of December 31, 2004. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are paid by Petrobras until August 2007 under a participation agreement. Petrobras failed to make any payments that were due under the participation agreement for December 2004 and January 2005. In 2005, Petrobras obtained a ruling from a Brazilian court directing Petrobras to deposit one-half of the payments to a court account and to pay us the other half. We are appealing this ruling. Petrobras has also failed to make any payments required under the court order. As of December 31, 2004, our accounts receivable balance is approximately $20 million. Petrobras has also filed a notice of arbitration with an international arbitration institution that effectively seeks rescission of the participation agreement and reimbursement of a portion of the capacity payments that it has made. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras's obligation to provide a firm gas supply to the project through 2012. We believe we have substantial defenses to the claims of Petrobras and will vigorously defend our legal rights. In addition, we will continue to seek reasonable negotiated settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $320 million at December 31, 2004, and Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $320 million of debt as current. We also have restricted cash balances of approximately $76 million as of December 31, 2004, which are reflected in current assets, related to required debt service reserve balances, debt service payment accounts and funds held for future distribution by Macae. We have also issued cash collateralized letters of credit of approximately $47 million as part of funding the required debt service reserve accounts. The restricted cash related to these letters of credit has also been classified as a current asset. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise certain remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

In light of the pending arbitration proceedings, we have evaluated whether any impairment of our investment in the project is required at December 31, 2004. Based upon our review of the possible outcomes of the arbitration and potential settlements of the dispute, we do not believe that an impairment of our investment is required at this time. However, if our assessment of the potential outcomes of the arbitration or settlement opportunities changes, we may be required to write down some or all of our investment in the project. In the event that the lenders call the loans and ultimately foreclose on the project, our loss would be approximately $500 million as of December 31, 2004. As new information becomes available or future material developments occur, we will reassess our carrying value of this investment.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. Our costs and legal exposure related to these lawsuits are not currently determinable.

Wise Arbitration. William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached employment and other agreements by failing to make certain payments to him following his departure from El Paso in 2003. Discovery is underway, with a hearing scheduled in the summer of 2005.

Government Investigations

Power Restructuring. In October 2003, we announced that the SEC had authorized the staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We have cooperated with the SEC investigation.

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

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

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

Storage Reporting. In November 2004, ANR and TGP received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the Energy Information Administration (EIA) for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR and TGP provided information on their weekly EIA submissions for two weeks in November 2004. Neither ANR nor TGP's submissions to the EIA were revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC and ANR provided the requested information. On December 17, 2004, the FERC held a press conference in which they disclosed that their inquiry had determined that an unaffiliated third party was the source of the downward revision.

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

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

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

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

A number of civil actions were filed against EPNG in connection with the rupture which have now been settled or should be fully covered by insurance.

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

Rates and Regulatory Matters

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

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

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

Other Contingencies

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. (ENA) and Enron Power Marketing, Inc. (EPMI) filed for Chapter 11 bankruptcy protection in New York. We had various contracts with Enron marketing and trading entities, and most of the trading-related contracts were terminated due to the bankruptcy. In October 2002, we filed proofs of claims against the Enron trading entities totaling approximately $317 million.

> *Enron Trading Claims.* We have largely sold or settled all of our original claims of our trading entities with Enron. In particular, on June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved most of our trading or merchant issues between the parties for which final payments were made in the third quarter of 2004. The only remaining trading claims involve our European trading businesses, claims against Enron Capital and Trade Resources Limited, which are subject to separate proceedings in the United Kingdom, in addition to a corresponding claim against Enron Corp. based on a corporate guarantee. After considering the valuation and setoff arguments and the reserves we have established, we believe our overall remaining trading exposure to Enron is $3 million.
>
> *Enron Pipeline Claims.* In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts were rejected, and our pipeline subsidiaries filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. EPNG expects that Enron will vigorously contest these claims. Our remaining pipeline claimants, ANR TGP and WIC, are in various stages of attempting to resolve their claims with Enron. Given the uncertainty of the bankruptcy process, the results are uncertain. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since that time.

Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil. Our total investment in Brazil was approximately $1.6 billion as of December 31, 2004.

Although economic conditions have generally improved over the last year, Brazil has experienced high interest rates on local debt and has experienced restrictions on the availability of foreign funds and investment. In addition, in a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. We also own an investment in a power plant in Brazil called Porto Velho. The Porto Velho project is in the process of negotiating certain provisions of its PPAs with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant's capacity. The project expects to replace or repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the proposed amendments do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was $292 million at December 31, 2004.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the item, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, then we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of December 31, 2004, we had approximately $592 million net of related insurance receivables accrued for our outstanding legal and other contingencies, including amounts accrued for our Western Energy Settlement.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2004, we had accrued approximately $380 million, including approximately $373 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $7 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $380 million accrual, $100 million was reserved for facilities we currently operate, and $280 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $380 million to approximately $547 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($82 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($298 million to $465 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	December 31, 2004	
Sites	**Expected**	**High**
	(In millions)	
Operating	$100	$111
Non-operating	249	384
Superfund	31	52
Total	$380	$547

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

Balance as of January 1, 2004	$412
Additions/adjustments for remediation activities	17
Payments for remediation activities	(51)
Other changes, net	2
Balance as of December 31, 2004	$380

For 2005, we estimate that our total remediation expenditures will be approximately $64 million. In addition, we expect to make capital expenditures for environmental matters of approximately $62 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the EPA List of Hazardous Substances (HSL), at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations, and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at its Pennsylvania and New York stations.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of December 31, 2004, TGP had pre-collected PCB costs by approximately $125 million. This pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of December 31, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $97 million for estimated future refund obligations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 61 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $52 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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

Commitments and Purchase Obligations

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2005 until 2053. As of December 31, 2004, our total commitments under operating leases were approximately $442 million. Minimum annual rental commitments under our operating leases at December 31, 2004, were as follows:

Year Ending December 31,	Operating Leases (In Millions)
2005	$ 79
2006	66
2007	51
2008	43
2009	40
Thereafter	163
Total	$442

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $28 million due in the future under noncancelable subleases. Rental expense on our operating leases for the years ended December 31, 2004, 2003 and 2002 was $101 million, $113 million and $116 million.

In May 2004, we announced we would consolidate our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004 we have established an accrual totaling $80 million to record the liability, net of sublease rentals, for our obligations under our existing lease terms. We currently lease approximately 888,000 square feet of office space in the buildings we are vacating under various leases with lease terms expiring through 2014. See Note 4 for additional information regarding these lease terminations.

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

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

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2004, we had firm commitments under tolling, transportation and storage capacity contracts of $1.5 billion, commodity purchase commitments of $149 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $224 million.

18. Retirement Benefits

Pension Benefits

Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat or Coastal receive the greater of cash balance benefits or transition benefits under the prior plan formulas. Transition benefits reflect prior plan accruals for these employees through December 31, 2001, December 31, 2004 and March 31, 2006. We do not anticipate making any contributions to this pension plan in 2005.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We also maintain two other pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. The SERP and the frozen plans together are referred to below as other pension plans. We also participate in one multi-employer pension plan for the benefit of our former employees who were union members. Our contributions to this plan during 2004, 2003 and 2002 were not material. We expect to contribute $5 million to the SERP in 2005. We do not anticipate making any contributions to our other pension plans in 2005.

During 2004, we recognized a $4 million curtailment benefit in our pension plans primarily related to a reduction in the number of employees that participate in our pension plan, which resulted from our various asset sales and employee severance efforts. During 2003, we recognized $11 million in charges in our pension plans that resulted from employee terminations and our internal reorganization.

Retirement Savings Plan

We maintain a defined contribution plan covering all of our U.S. employees. Prior to May 1, 2002, we matched 75 percent of participant basic contributions up to 6 percent, with the matching contributions being made to the plan's stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, we suspended the matching contributions, but reinstituted it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, we increased the matching contributions to 75 percent of participant basic contributions up to 6 percent. Amounts expensed under this plan were approximately $16 million, $14 million and $28 million for the years ended December 31, 2004, 2003 and 2002.

Other Postretirement Benefits

We provide postretirement medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. We expect to contribute $63 million to our postretirement plans in 2005. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits.

Below is our projected benefit obligation, accumulated benefit obligation, fair value of plan assets as of September 30, our plan measurement date, and related balance sheet accounts for our pension plans as of December 31:

	Primary Pension Plan		Other Pension Plans	
	2004	2003	2004	2003
	(In millions)			
Projected benefit obligation	$1,948	$1,928	$170	$163
Accumulated benefit obligation	1,934	1,902	169	163
Fair value of plan assets	2,196	2,104	93	93
Accrued benefit liability	—	—	74	69
Prepaid benefit cost	960	960	—	21
Accumulated other comprehensive loss	—	—	70	37

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

	2004	2003
	(In millions)	
Projected benefit obligation	$170	$134
Accumulated benefit obligation	169	134
Fair value of plan assets	93	63

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded other comprehensive income (loss) of $(33) million in 2004 and $18 million in 2003 related to the change in this additional minimum liability.

Below is the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our pension and other postretirement benefit plans. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$2,091	$2,088	$ 575	$ 558
Service cost	31	36	1	1
Interest cost	121	134	34	35
Participant contributions	—	—	27	24
Settlements, curtailments and special termination benefits	(3)	—	—	(6)
Actuarial loss (gain)	76	22	(20)	50
Benefits paid	(198)	(189)	(76)	(87)
Projected benefit obligation at end of period	$2,118	$2,091	$ 541	$ 575
Change in plan assets:				
Fair value of plan assets at beginning of period	$2,197	$2,072	$ 196	$ 164
Actual return on plan assets	277	285	12	25
Employer contributions	12	29	61	70
Participant contributions	—	—	27	24
Benefits paid	(198)	(189)	(76)	(87)
Administrative expenses	1	—	—	—
Fair value of plan assets at end of period	$2,289	$2,197	$ 220	$ 196

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Reconciliation of funded status:				
Fair value of plan assets at September 30	$2,289	$2,197	$ 220	$ 196
Less: Projected benefit obligation at end of period	2,118	2,091	541	575
Funded status at September 30	171	106	(321)	(379)
Fourth quarter contributions and income	2	2	13	17
Unrecognized net actuarial loss[1]	800	868	32	57
Unrecognized net transition obligation	—	1	8	15
Unrecognized prior service cost	(17)	(28)	(6)	(7)
Prepaid (accrued) benefit cost at December 31	$ 956	$ 949	$(274)	$(297)

[1] The decrease in unrecognized net actuarial loss in our pension benefits was primarily due to historical changes and assumptions on discount rates, expected return on plan assets and rate of compensation increase. We recognize the difference between the actual return and our expected return over a three year period as permitted by SFAS No. 87. The decrease in unrecognized net actuarial loss in our other postretirement benefits was primarily due to the adoption of FSP No. 106-2.

The portion of our other postretirement benefit obligation included in current liabilities was $38 million and $45 million as of December 31, 2004 and 2003.

Future benefits expected to be paid from our pension plans and our other postretirement plans as of December 31, 2004, are as follows:

Year Ending December 31,	Pension Benefits	Other Postretirement Benefits[1]
	(In millions)	
2005	$ 160	$ 57
2006	160	52
2007	161	50
2008	161	48
2009	160	46
2010-2014	788	208
Total	$1,590	$461

[1] Includes a reduction of $3 million in each year excluding 2005 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	(In millions)					
Service cost	$ 31	$ 36	$ 33	$ 1	$ 1	$ 2
Interest cost	121	134	135	34	35	38
Expected return on plan assets	(187)	(227)	(260)	(11)	(9)	(9)
Amortization of net actuarial (gain) loss	47	7	—	4	1	(1)
Amortization of transition obligation	—	(1)	(6)	8	8	8
Amortization of prior service cost[1]	(3)	(3)	(3)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	(4)	11	—	—	(6)	—
Net benefit cost (income)	$ 5	$ (43)	$(101)	$ 35	$29	$37

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

Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit costs of our pension and other postretirement plans for 2004, 2003 and 2002:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	5.75	6.00		5.75	6.00	
Rate of compensation increase	4.00	4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.00	6.75	7.25	6.00	6.75	7.25
Expected return on plan assets(1)	8.50	8.80	8.80	7.50	7.50	7.50
Rate of compensation increase	4.00	4.00	4.00			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 26 percent to 27 percent on other postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio. For 2005, the assumed expected return on assets for pension benefits will be reduced to 8 percent.

Actuarial estimates for our other postretirement benefit plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

	2004	2003
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	19	21
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(18)	(19)

Plan Assets

The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

	Pension Plans			Other Postretirement Plans		
Asset Category	Target	Actual 2004	Actual 2003	Target	Actual 2004	Actual 2003
		(Percent)			(Percent)	
Equity securities(1)	60	62	70	65	60	29
Debt securities	40	37	29	35	33	60
Other	—	1	1	—	7	11
Total	100	100	100	100	100	100

(1) Actuals for our pension plans include $42 million (1.8 percent of total assets) and $33 million (1.5 percent of total assets) of our common stock at September 30, 2004 and September 30, 2003.

The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

In 2003, we modified our target asset allocations for our other postretirement benefit plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2004 were close to our targets. During 2004, we modified our target and actual asset allocations for our pension plans to reduce our equity allocation to 60 percent of total plan assets. Correspondingly, our 2005 assumption related to the expected return on plan assets were reduced from 8.5 percent to 8.0 percent to reflect this change.

19. Capital Stock

Common Stock

In 2003 and 2004, we issued 26.4 million shares to satisfy our obligations under the Western Energy Settlement (See Note 17). In 2003, we also issued 15 million shares as part of an offer to exchange our equity security units for common stock (see Note 15).

Dividend

For the year ended December 31, 2004, we paid dividends of $101 million to common stockholders. On February 18, 2005, we declared quarterly dividends of $0.04 per share on our common stock, payable on April 4, 2005 to the shareholders of record on March 4, 2005. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit.

El Paso Tennessee Pipeline Co., our subsidiary, pays dividends of approximately $6 million each quarter on its Series A cumulative preferred stock, which is 8.25 percent per annum (2.0625 percent per quarter).

20. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using Accounting Principles Board Opinion No. 25 and its related interpretations. Under our employee plans, we may issue incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, stock appreciation rights, phantom stock options, and performance units. Under our non-employee director plan, we may issue deferred shares of common stock. We have reserved approximately 68 million shares of common stock for existing and future stock awards, including deferred shares. As of December 31, 2004, approximately 28 million shares remained unissued.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2004, 2003 and 2002. Our stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. Prior to 2004, we also granted options to non-employee members of the Board of Directors at fair market value on the grant date that were exercisable immediately. A summary of our stock option transactions, stock options outstanding and stock options exercisable as of December 31 is presented below:

	Stock Options					
	2004		2003		2002	
	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price	# Shares of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	36,245,014	$47.90	43,208,374	$49.16	44,822,146	$50.02
Granted	4,842,453	$ 7.16	1,180,041	$ 7.29	3,435,138	$35.41
Exercised	(3,193)	$ 7.64	—	—	(310,611)	$22.44
Converted[1]	(11,333)	$42.99	(871,250)	$42.00	—	—
Forfeited or canceled	(7,149,363)	$44.75	(7,272,151)	$49.53	(4,738,299)	$51.83
Outstanding at end of year	33,923,578	$42.73	36,245,014	$47.90	43,208,374	$49.18
Exercisable at end of year	28,455,056	$49.45	28,703,151	$46.04	25,493,152	$43.00
Weighted average fair value of options granted during the year		$ 2.69		$ 3.21		$14.23

[1] Includes the conversion of stock options into common stock and cash at no cost to employees based upon achievement of certain performance targets and lapse of time. These options had an original stated exercise price of approximately $43 per share and $42 per share in 2004 and 2003.

The following table summarizes the range of exercise prices and the weighted-average remaining contractual life of options outstanding and the range of exercise prices for the options exercisable at December 31, 2004.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 0.00 - $21.39	7,537,238	7.1	$ 9.25	2,154,339	$14.35
$21.40 - $42.89	8,761,610	2.9	$37.53	8,707,300	$37.52
$42.90 - $64.29	12,302,057	3.6	$54.88	12,272,411	$54.91
$64.30 - $70.63	5,322,673	4.7	$70.59	5,321,006	$70.59
	33,923,578	4.4	$42.73	28,455,056	$49.45

The fair value of each stock option granted used to complete pro forma net income disclosures (see Note 1) is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption:	2004	2003	2002
Expected Term in Years	5.35	6.19	6.95
Expected Volatility	45%	52%	43%
Expected Dividends	2.1%	2.2%	1.8%
Risk-Free Interest Rate	3.7%	3.4%	3.2%

Restricted Stock

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our officers and employees. These shares carry voting and dividend rights; however, sale or transfer of the shares is restricted. These restricted stock awards vest over a specific period of time and/or if we achieve established performance targets. Restricted stock awards representing 3.1 million, 0.4 million, and 1.4 million shares were granted during 2004, 2003 and 2002 with a weighted-average grant date fair value of $8.63, $7.46 and $38.45 per share. At December 31, 2004, 3.9 million shares of restricted stock were outstanding. The value of restricted shares subject to performance vesting is determined based on the fair market value on the date performance targets are achieved, and this value is charged to compensation expense ratably over the required service or restriction period. The value of time vested restricted shares is determined at their issuance date and this cost is amortized to compensation expense over the vesting period. For 2004, 2003 and 2002, these charges totaled $23 million, $60 million and $73 million. We have $20 million on our balance sheet as of December 31, 2004 related to unamortized compensation that will be charged to expense over the vesting period of the restricted stock.

Performance Units

In the past, we awarded eligible officers performance units that were payable in cash or stock at the end of the vesting period. The final value of the performance units varied according to the plan under which they were granted, but was usually based on our common stock price at the end of the vesting period or total shareholder return during the vesting period relative to our peer group. The value of the performance units was charged ratably to compensation expense over the vesting period with periodic adjustments to account for the fluctuation in the market price of our stock or changes in expected total shareholder return. We recorded a credit to compensation expense in 2002 of $11 million upon the reduction of our performance unit liability by $21 million due to a reduction in our expected total shareholder return. In July 2003, all outstanding performance units vested at the "Below Threshold" level and the Compensation Committee of our Board of Directors determined that there would be no payout for the performance units. Accordingly, we reversed the remaining liability for these units and recorded income of $16 million.

Employee Stock Purchase Program

In October 1999, we implemented an employee stock purchase plan under Section 423 of the Internal Revenue Code. The plan allowed participating employees the right to purchase our common stock on a quarterly basis at 85 percent of the lower of the market price at the beginning or at the end of each calendar quarter. Five million shares of common stock are authorized for issuance under this plan. For the year ended December 31, 2002, we sold 1.4 million shares of our common stock to our employees. Effective January 1, 2003, we suspended our employee stock purchase program.

21. Business Segment Information

During 2004, we reorganized our business structure into two primary business lines, regulated and non-regulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established individual Power and Marketing and Trading segments. All periods presented reflect this change in segments. Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Marketing and Trading, Power, and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions as well as a telecommunications business, and various other contracts and assets, all of which are immaterial. These other assets and contracts include financial services, LNG and related items.

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

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the U.S. We conduct our activities primarily through eight wholly owned and four partially owned interstate transmission systems along with five underground natural gas storage entities and an LNG terminalling facility.

Our Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in the United States and Brazil. In the U.S., Production has onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico.

Our Marketing and Trading segment's operations focus on the marketing of our natural gas and oil production and the management of our remaining trading portfolio.

Our Power segment owns and has interests in domestic and international power assets. As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also had domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses. Our ongoing focus within the power segment will be to maximize the value of our assets in Brazil.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2004, 2003 and 2002.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

	2004	2003 (Restated)	2002 (Restated)
		(In millions)	
Total EBIT	$ 855	$ 769	$ (427)
Interest and debt expense	(1,607)	(1,791)	(1,297)
Distributions on preferred interests of consolidated subsidiaries	(25)	(52)	(159)
Income taxes	(25)	469	641
Loss from continuing operations	$ (802)	$ (605)	$(1,242)

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

	Segments As of or for the Year Ended December 31, 2004						
	Regulated	Non-regulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
	(In millions)						
Revenue from external customers							
Domestic	$ 2,554	$ 535[2]	$ 697	$ 241	$1,203	$ 132	$ 5,362
Foreign	9	26[2]	2	460	—	15	512
Intersegment revenue	88	1,174[2]	(1,207)	94	159	(308)	—
Operation and maintenance	777	365	53	374	102	201	1,872
Depreciation, depletion, and amortization	410	548	13	54	12	51	1,088
(Gain) loss on long-lived assets	(1)	8	—	583	508	(6)	1,092
Operating income (loss)	$ 1,129	$ 726	$ (562)	$ (408)	$ (465)	$ (214)	$ 206
Earnings from unconsolidated affiliates	173	4	—	(236)	618	—	559
Other income	33	4	15	84	2	51	189
Other expense	(4)	—	—	(9)	(35)	(51)	(99)
EBIT	$ 1,331	$ 734	$ (547)	$ (569)	$ 120	$ (214)	$ 855
Discontinued operations, net of income taxes	$ —	$ (76)	$ —	$ —	$ —	$ (70)	$ (146)
Assets of continuing operations[3]							
Domestic	15,930	3,714	2,372	982	686	4,424	28,108
Foreign[4]	58	366	32	2,617	—	96	3,169
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	1,047	728	—	29	(5)	10	1,809
Total investments in unconsolidated affiliates	1,032	6	—	1,262	308	6	2,614

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $308 million and an operation and maintenance expense elimination of $25 million, which is included in the "Corporate" column, to remove intersegment transactions.

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

(3) Excludes assets of discontinued operations of $106 million (see Note 3).

(4) Of total foreign assets, approximately $1.3 billion relates to property, plant and equipment and approximately $1.5 billion relates to investments in and advances to unconsolidated affiliates.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

Segments
As of or for the Year Ended December 31, 2003

	Regulated	Non-regulated					
	Pipelines	Production (Restated)	Marketing and Trading	Power	Field Services	Corporate[1]	Total (Restated)
	(In millions)						
Revenue from external customers							
Domestic	$ 2,527	$ 201[2]	$ 1,430	$ 515	$1,153	$ 113	$ 5,939
Foreign	2	—	—	516	2	13	533
Intersegment revenue	118	1,940[2]	(2,065)	145	374	(316)	196[3]
Operation and maintenance	720	342	183	562	110	93	2,010
Depreciation, depletion, and amortization	386	576	25	91	31	67	1,176
Western Energy Settlement	127	—	(25)	—	—	2	104
(Gain) loss on long-lived assets	(10)	5	(3)	185	173	510	860
Operating income (loss)	$ 1,063	$1,073	$ (819)	$ (13)	$ (193)	$ (706)	$ 405
Earnings (losses) from unconsolidated affiliates	119	13	—	(91)	329	(7)	363
Other income	57	5	12	90	—	39	203
Other expense	(5)	—	(2)	(14)	(3)	(178)	(202)
EBIT	$ 1,234	$1,091	$ (809)	$ (28)	$ 133	$ (852)	$ 769
Discontinued operations, net of income taxes	$ —	$ (11)	$ —	$ —	$ —	$(1,303)	$(1,314)
Cumulative effect of accounting changes, net of income taxes	(4)	(3)	—	—	(2)	—	(9)
Assets of continuing operations[4]							
Domestic	15,659	3,459	2,661	3,897	1,990	3,889	31,555
Foreign	27	308	5	3,102	—	141	3,583
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	837	1,300	(1)	1,083	(15)	89	3,293
Total investments in unconsolidated affiliates	1,018	79	—	1,652	655	5	3,409

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $316 million and an operation and maintenance expense elimination of $59 million, which is included in the "Corporate" column, to remove intersegment transactions.

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

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

(4) Excludes assets of discontinued operations of $1.8 billion (see Note 3).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital. Our Power Segment Includes $1 billion to acquire remaining interest in Chaparral and Gemstone (see Note 2).

	Regulated	Non-regulated					
	Pipelines (Restated)	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total (Restated)
				(In millions)			
Segments As of or for the Year Ended December 31, 2002							
Revenue from external customers							
Domestic	$ 2,389	$ 308[2]	$ 926	$1,268	$1,145	$ 97	$ 6,133
Foreign	3	—	(41)	361	3	79	405
Intersegment revenue	218	1,623[2]	(2,209)	43	881	(213)	343
Operation and maintenance	752	368	173	520	179	99	2,091
Depreciation, depletion, and amortization	374	601	11	45	56	72	1,159
Western Energy Settlement	412	—	487	—	—	—	899
(Gain) loss on long-lived assets	(13)	(1)	—	160	(179)	214	181
Operating income (loss)	$ 788	$ 803	$(1,993)	$ 352	$ 273	$ (394)	$ (171)
Earnings (losses) from unconsolidated affiliates	10	7	—	(256)	18	7	(214)
Other income	34	1	19	40	3	100	197
Other expense	(4)	(3)	(3)	(124)	(5)	(100)	(239)
EBIT	$ 828	$ 808	$(1,977)	$ 12	$ 289	$ (387)	$ (427)
Discontinued operations, net of income taxes	$ —	$ (68)	$ —	$ —	$ —	$ (357)	$ (425)
Cumulative effect of accounting changes, net of income taxes	—	—	(222)	14	—	—	(208)
Assets of continuing operations[4]							
Domestic	14,727	3,495	5,568	2,759	2,714	4,265	33, 528
Foreign	59	208	844	2,485	14	277	3,887
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	1,075	2,114	47	91	187	48	3,562
Total investments in unconsolidated affiliates	992	87	—	2,725	922	23	4,749

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $213 million and an operation and maintenance expense elimination of $41 million, which is included in the "Corporate" column, to remove intersegment transactions.

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

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

(4) Excludes assets of discontinued operations of $4.5 billion (see Note 3).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

22. Investments in, Earnings from and Transactions with Unconsolidated Affiliates

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants, and gathering systems. Our investment balance was less than our equity in the net assets of these investments by $265 million and $136 million as of December 31, 2004 and 2003. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the year ended December 31:

	Net Ownership Interest		Investment		Earnings from Unconsolidated Affiliates		
	2004	2003	2004	2003 (Restated)	2004	2003	2002 (Restated)
	(Percent)		(In millions)			(In millions)	
Domestic:							
Citrus	50	50	$ 589	$ 593	$ 65	$ 43	$ 43
Enterprise Products Partners[1]	—[1]	—	257	—	6	—	—
GulfTerra Energy Partners[1]	—	—[1]	—	599	601	419	69
Midland Cogeneration Venture[2]	44	44	191	348	(171)	29	28
Great Lakes Gas Transmission[3]	50	50	316	325	65	57	63
Javelina	40	40	45	40	15	(2)	—
Milford[4]	—	—	—	—	(1)	(88)	(22)
Bastrop Company[5]	—	50	—	73	(1)	(48)	(5)
Mobile Bay Processing[5]	—	42	—	11	—	(48)	(2)
Blue Lake Gas Storage[6]	—	75	—	30	—	9	8
Chaparral Investors (Electron)[7]	—	—	—	—	—	(207)	(62)
Linden Venture L.P. (East Coast Power)	—	—	—	—	—	65	—
Dauphin Island[5]	—	15	—	—	—	(40)	(1)
Alliance Pipeline Limited Partnership[4]	—	—	—	—	—	—	25
CE Generation[4]	—	—	—	—	—	—	(52)
Aux Sable NGL	—	—	—	—	—	—	(50)
Other Domestic Investments	various	various	136	137	26	26	29
Total domestic			1,534	2,156	605	215	71
Foreign:							
Korea Independent Energy Corporation	50	50	176	145	22	29	24
Araucaria Power[8]	60	60	186	181	—	—	—
EGE Itabo	25	25	88	87	1	1	(2)
Bolivia to Brazil Pipeline	8	8	86	66	24	17	2
EGE Fortuna	25	25	65	59	6	3	5
Meizhou Wan Generating	26	25	52	63	(14)	8	(20)
Enfield Power[9]	25	25	51	55	1	3	(3)
Aguaytia Energy	24	24	39	51	(5)	4	3
San Fernando Pipeline	50	50	46	41	13	5	—
Habibullah Power[10]	50	50	20	48	(46)	(3)	10
Gasoducto del Pacifico Pipeline	22	22	33	37	4	3	(2)
Samalayuca[11]	50	50	35	24	5	3	21
Saba Power Company	94	94	7	59	(51)	4	7
Australian Pipelines[5]	—	33	—	38	4	(3)	(142)
UnoPaso[6]	—	50	—	73	4	14	6
Diamond Power (Gemstone)[7]	—	—	—	—	—	17	109
CAPSA[4]	—	—	—	—	—	24	(262)
PPN[12]	26	26	—	—	—	—	(50)
Agua del Cajon[4]	—	—	—	—	—	—	(24)
Other Foreign Investments[10]	various	various	196	226	(14)	19	33
Total foreign			1,080	1,253	(46)	148	(285)
Total investments in unconsolidated affiliates			$2,614	$ 3,409			
Total earnings (losses) from unconsolidated affiliates					$ 559	$ 363	$ (214)

(1) As of December 31, 2003, we owned an effective 50 percent interest in the one percent general partner of GulfTerra, approximately 17.8 percent of the partnership's common units and all of the outstanding Series C units. During 2004 we sold our remaining interest in GulfTerra to Enterprise for cash and equity interests in Enterprise and recognized a $507 million gain. As of December 31, 2004, our ownership consisted of a 9.9 percent interest in the two percent general partner of Enterprise and approximately 3.7 percent of Enterprise's common units. In January 2005, we sold all of these remaining interests to Enterprise. For a further discussion of our interests in GulfTerra and Enterprise, see page 165.

(2) Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.

(3) Includes a 47 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 3 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.

(4) In 2003 we completed the sale or transfer of our interest in this investment.

(5) In 2004 we completed the sale of our interest in this investment.

(6) Consolidated in 2004.

(7) This investment was consolidated in 2003.

(8) Our investment in Araucaria Power was included in Diamond Power (Gemstone) prior to 2003.

(9) We have signed an agreement to sell our interest in the project and expect to close the transaction in the first half of 2005.

(10) As of December 31, 2004 and 2003, we also had outstanding advances of $64 million and $90 million related to our investment in Habibullah Power. We also had other outstanding advances of $318 million and $327 million related to our other foreign investments as of December 31, 2004 and 2003, of which $307 million and $290 million are related to our investment in Porto Velho.

(11) Consists of investments in a power facility and pipeline. In 2002, we sold our investment in the power facility.

(12) Impaired in 2002 due to our inability to recover our investment. Earnings generated in 2003 and 2004 did not improve the recoverability of this investment. We sold our interest in March 2005.

Our impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates during 2004, 2003 and 2002 consisted of the following:

Investment	Pre-tax Gain (Loss) (In millions)	Cause of Impairments or Gain (Loss)
2004		
Gain on sale of interests in GulfTerra[1]	$ 507	Sale of investment
Asian power investments[2]	(182)	Anticipated sales of investments
Midland Cogeneration Venture	(161)	Decline in investment's fair value based on increased fuel costs
Power investments held for sale	(49)	Anticipated sales of investments
Net gain on domestic power investment sales[3]	7	Sales of power investments
Other	7	
Total	$ 129	
2003		
Gain on sale of interests in GulfTerra[4]	$ 266	Sale of various investment interests in GulfTerra
Chaparral Investors (Electron)	(207)	Decline in the investment's fair value based on developments in our power business and the power industry
Milford power facility[5]	(88)	Transfer of ownership to lenders
Dauphin Island Gathering/Mobile Bay Processing	(86)	Decline in the investments' fair value based on the devaluation of the underlying assets
Bastrop Company	(43)	Decision to sell investment
Linden Venture, L.P. (East Coast Power)	(22)	Sale of investment in East Coast Power
Other investments	4	
Total	$(176)	
2002 (Restated)		
CAPSA/CAPEX	$(262)	Weak economic conditions in Argentina
EPIC Australia	(141)	Regulatory difficulties and the decision to discontinue further capital investment
CE Generation	(74)	Sale of investment
Aux Sable NGL	(47)	Sale of investment
Agua del Cajon	(24)	Weak economic conditions in Argentina
PPN	(41)	Loss of economic fuel supply and payment default
Meizhou Wan Generating	(7)	Weak economic conditions in China
Other investments	(16)	
Total	$(612)	

(1) In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we sold to affiliates of Enterprise substantially all of our interests in GulfTerra. See further discussion of GulfTerra beginning on page 165.

(2) Includes impairments of our investments in Korea Independent Energy Corporation, Meizhou Wan Generating, Habibullah Power, Saba Power Company and several other foreign power investments.

(3) Includes a loss on the sale of Bastrop Company and gains on the sale of several other domestic investments.

(4) In 2003, we sold 50 percent of the equity of our consolidated subsidiary that holds our 1 percent general partner interest. This was recorded as minority interest in our balance sheet.

(5) In December 2003, we transferred our ownership interest in Milford to its lenders in order to terminate all of our obligations associated with Milford.

Below is summarized financial information of our proportionate share of unconsolidated affiliates. This information includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. We received distributions and dividends of $358 million and $398 million in 2004 and 2003, which includes $23 million and $53 million of returns of capital, from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $15 million, $119 million and $26 million in 2004, 2003 and 2002 and total assets of $734 million and $1.1 billion as of December 31, 2004 and 2003.

	Year Ended December 31,		
	2004	2003	2002
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$2,211	$3,360	$2,486
Operating expenses	1,485	2,309	1,632
Income from continuing operations	388	519	422
Net income	388	520	445

	December 31,	
	2004	2003
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$1,270	$ 1,024
Non-current assets	5,243	8,001
Short-term debt	250	1,169
Other current liabilities	488	645
Long-term debt	2,044	1,892
Other non-current liabilities	779	1,703
Minority interest	73	71
Equity in net assets	2,879	3,545

Below is summarized financial information of GulfTerra (in millions):

	Nine months ended September 30, 2004	Year Ended December 31, 2003	Year ended December 31, 2002
	(Unaudited)		
Operating results data:			
Net sales or gross revenues	$677	$871	$457
Operating expenses	432	557	297
Income from continuing operations	155	161	93
Net income	155	163	98

	As of September 30, 2004	As of December 31, 2003
	(Unaudited)	
Financial position data:		
Current assets	$ 230	$ 209
Noncurrent assets	3,167	3,113
Current liabilities	200	209
Noncurrent liabilities	1,921	1,860
Equity in net assets	1,276	1,253

The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates:

	2004	2003	2002
		(In millions)	
Operating revenue	$218	$216	$ 65
Other revenue — management fees	4	13	192
Cost of sales	102	106	178
Reimbursement for operating expenses	97	140	186
Other income	8	10	18
Interest income	8	11	30
Interest expense	—	2	42

Chaparral and Gemstone

As of December 31, 2002, we held equity investments in Chaparral and Gemstone. During 2003, we acquired the remaining third party equity interests and all of the voting rights in both of these entities. As discussed in Note 2, we consolidated Chaparral effective January 1, 2003 and Gemstone effective April 1, 2003.

GulfTerra

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

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge to form the second largest publicly traded energy partnership in the U.S. On July 29, 2004, GulfTerra's unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004. In January 2005, we sold our remaining 9.9 percent interest in the two percent general partner of Enterprise and approximately 13.5 million common units in Enterprise for $425 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million.

In the December 2003 sales transactions, specific evaluation procedures were instituted to ensure that they were in the best interests of us and the partnership and were based on fair values. These procedures required our Board of Directors to evaluate and approve, as appropriate, each transaction with GulfTerra. In addition, a special committee comprised of the GulfTerra general partner's independent directors evaluated the transactions on GulfTerra's behalf. Both boards engaged independent financial advisors to assist with the evaluation and to opine on its fairness.

Below is a detail of the gains or losses recognized in earnings from unconsolidated affiliates on transactions related to GulfTerra/Enterprise and other significant transactions during 2002, 2003, and 2004:

Transaction	Proceeds	Realized Gain/(Loss)
	(In millions)	
2002		
Sold San Juan Basin gathering, treating, and processing assets and Texas & New Mexico midstream assets to GulfTerra[1]	$1,501	$210
2003		
Sold 9.9% of our 1% general partner interest in GulfTerra to Goldman Sachs	88	—
Repurchased the 9.9% interest from Goldman Sachs[2]	(116)	(28)
Redeemed series B preference units	156	(11)
Released from obligation in 2021 to purchase Chaco facility[3]	(10)	67
Sold 50% general partnership interest in GulfTerra to Enterprise[4]	425	297
Other GulfTerra common unit sales	23	8
2004		
Sold our interest in the general partner of GulfTerra, 2.9 million common units and 10.9 million series C units in GulfTerra to Enterprise[5][6]	951	507

(1) We received $955 million of cash, Series C units in GulfTerra with a value of $356 million, and an interest in a production field with a value of $190 million. We recorded an additional $74 million liability and related loss in 2003 for future pipeline integrity costs related to the transmission assets, for which we agreed to reimburse GulfTerra through 2006.

(2) We paid $92 million in cash and transferred GulfTerra common units with a book value of $19 million to Goldman Sachs in December 2003. We also paid $5 million of miscellaneous expenses related to the repurchase.

(3) We satisfied our obligation to GulfTerra through the transfer of communications assets with a book value of $10 million.

(4) The cash flows were reflected in our 2003 cash flow statement as an investing activity and $84 million of the proceeds were reflected as minority interest on our balance sheet. We also agreed to pay $45 million to Enterprise through 2006.

(5) We received $870 million in cash and a 9.9 percent interest in the general partner of the combined organization, Enterprise Products GP, with a fair value of $82 million. We also exchanged our remaining GulfTerra common units for 13.5 million Enterprise common units.

(6) As a result of the Enterprise transaction, we also recorded a $480 million impairment of the goodwill in loss on long-lived assets on our income statement associated with our Field Services segment. In addition, we sold South Texas assets to Enterprise for total proceeds of $156 million and a loss of $11 million included in our loss on long-lived assets.

Prior to the sale of our interests in GulfTerra to Enterprise in September 2004, a subsidiary in our Field Services segment served as the general partner of GulfTerra, a publicly traded master limited partnership. We had the following interests in GulfTerra (Enterprise effective September 30, 2004) as of December 31:

	2004		2003	
	Book Value	Ownership	Book Value	Ownership
	(In millions)	(Percent)	(In millions)	(Percent)
One Percent General Partner[1]	$ 82	9.9	$194	100.0
Common Units	175	3.7	251	17.8
Series C Units	—	—	335	100.0
Total	$257		$780	

(1) We had $181 million of indefinite-lived intangible assets related to our general partner interest as of December 31, 2003. We also have $96 million recorded as minority interest related to the effective general partnership interest acquired by Enterprise in December 2003. This reduced our effective ownership interest in the general partner to 50 percent. Both of these were disposed of in the Enterprise sales described above.

During each of the three years ended December 31, 2004, we conducted the following transactions with GulfTerra:

	2004	2003	2002
		(In millions)	
Revenues received from GulfTerra			
Field Services	$ 2	$ 5	$ 1
Marketing and Trading	26	28	19
Production	—	—	3
	$ 28	$ 33	$ 23
Expenses paid to GulfTerra			
Field Services	$ 84	$ 75	$ 97
Marketing and Trading	20	30	93
Production	9	9	9
	$113	$114	$199
Reimbursements received from GulfTerra			
Field Services	$ 71	$ 91	$ 60

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $103 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso. As a consequence of economic conditions described above, combined with the high prices on imported fuels and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales which may affect CEPP's ability to operate. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments may occur.

Berkshire Power Project. We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. We supply natural gas to Berkshire under a fuel management agreement. Berkshire has the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million, if Berkshire does not have available cash to meet its debt service requirements. Berkshire has delayed a total of $46 million of its fuel payments, including $8 million of interest, under this agreement as of December 31, 2004. During 2002, Berkshire's lenders asserted that Berkshire was in default on its loan agreement, and these issues remain unresolved. Based on the uncertainty surrounding these negotiations and Berkshire's inability to generate adequate future cash flow, we recorded losses of $10 million and $28 million in 2004 and 2003 associated with the amounts due to us under the fuel supply agreement.

For contingent matters that could impact our investments in Brazil, see Note 17.

For a discussion of non-recourse project financing, see Note 15.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
El Paso Corporation:

We have completed an integrated audit of El Paso Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements and Financial Statement Schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the second and fourth paragraphs of Note 1, the 2002 and 2003 consolidated financial statements have been restated.

As discussed in the notes to the consolidated financial statements, the Company adopted FASB Financial Interpretation No. 46, *Consolidation of Variable Interest Entities* on January 1, 2004; FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* on July 1, 2004; Statement of Financial Accounting Standards (SFAS) No. 150*, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; SFAS No. 143, *Accounting for Asset Retirement Obligations* and SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* on January 1, 2003; SFAS No. 141, *Business Combinations*, SFAS No. 142, *Goodwill and Other Intangible Assets* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions; applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* on July 1, 2002 and EITF Issue No. 02-03, *Accounting for the Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2*, on October 1, 2002.

Internal Control Over Financial Reporting

Also, we have audited management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, which includes consideration of the matter referred to in the fourth paragraph of Note 1, that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, because the Company did not maintain effective controls over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. Management's assessment was based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management's assessment. At December 31, 2004, the Company did not maintain effective control over (1) access to financial applications programs and data, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. A specific description of these control deficiencies which management concluded are material weaknesses, that existed at December 31, 2004, is discussed below.

Access to Financial Application Programs and Data. At December 31, 2004, the Company did not maintain effective controls over access to financial application programs and data at each of its operating segments. Internal control deficiencies were identified with respect to inadequate design of and compliance with security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and lack of independent monitoring of access to various systems by information technology staff, as well as certain users with accounting and reporting responsibilities who also have security administrator access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of the Company's financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, price risk management assets and liabilities, and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

Account Reconciliations. At December 31, 2004, the Company did not maintain effective controls over the preparation and review of account reconciliations related to accounts such as prepaid insurance, accounts receivable, other assets and taxes other than income taxes. Specifically, instances were identified in the Power and Marketing and Trading businesses where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. Instances were also noted where accounts were not being reconciled and reviewed by individuals with adequate accounting experience and training. These control deficiencies resulted in adjustments impacting the fourth quarter of 2004 financial statements. Furthermore, these control deficiencies could result in a misstatement of the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities. At December 31, 2004, the Company did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. Control deficiencies were identified related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment of long-lived assets, and accounting for divestiture of assets. These control deficiencies resulted in the restatement of the 2002 and, as described in the fourth paragraph of Note 1, the 2003 financial statements and related 2003 fourth quarter information as reflected in this annual report as well as adjustments to the aforementioned accounts impacting the financial statements for the fourth quarter of 2004. Furthermore, these control deficiencies could result in a material misstatement in the aforementioned accounts that would result in a misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly these control deficiencies constitute a material weakness.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

In our opinion, management's assessment that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control — Integrated Framework* issued by COSO. Also, in our opinion, because of the effects of the material weaknesses described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by COSO.

PricewaterhouseCoopers LLP
Houston, Texas
March 25, 2005, except for the
fourth paragraph of Note 1
as to which the date
is April 8, 2005

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(In millions, except per common share amounts)				
2004					
Operating revenues	$1,557	$ 1,524	$1,429	$1,364	$ 5,874
Loss on long-lived assets	222	17	582	271	1,092
Operating income (loss)	205	370	(355)	(14)	206
Income (loss) from continuing operations	$ (97)	$ 45	$ (202)	$ (548)	$ (802)
Discontinued operations, net of income taxes[1]	(109)	(29)	(12)	4	(146)
Net income (loss)	$ (206)	$ 16	$ (214)	$ (544)	$ (948)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	$(0.15)	$ 0.07	$(0.31)	$(0.86)	$ (1.25)
Discontinued operations, net of income taxes	(0.17)	(0.04)	(0.02)	0.01	(0.23)
Net income (loss)	$(0.32)	$ 0.03	$(0.33)	$(0.85)	$ (1.48)
2003 (Restated)					
Operating revenues	$1,828	$ 1,569	$1,714	$1,557	$ 6,668
Loss on long-lived assets	14	395	54	397	860
Western Energy Settlement	—	123	(20)	1	104
Operating income (loss)	264	(272)	481	(68)	405
Income (loss) from continuing operations	$ (207)	$ (297)	$ 65	$ (166)[2]	$ (605)
Discontinued operations, net of income taxes[1]	(215)	(939)	(41)	(119)[2]	(1,314)
Cumulative effect of accounting changes, net of income taxes	(9)	—	—	—	(9)
Net income (loss)	$ (431)	$(1,236)	$ 24	$ (285)	$(1,928)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	$(0.34)	$ (0.50)	$ 0.11	$(0.27)[2]	$ (1.01)
Discontinued operations, net of income taxes	(0.36)	(1.57)	(0.07)	(0.20)[2]	(2.20)
Cumulative effect of accounting changes, net of income taxes	(0.02)	—	—	—	(0.02)
Net income (loss)	$(0.72)	$ (2.07)	$ 0.04	$(0.47)	$ (3.23)

[1] Our petroleum markets operations, our Canadian and certain other international natural gas and oil production operations, and our coal mining operations are classified as discontinued operations (See Note 3 for further discussion).

[2] Amounts previously reported for loss from continuing operations were $(84) million or $(0.14) per share, and the loss for discontinued operations, net of income taxes was $(201) million or $(0.33) per share. See Note 1 to the consolidated financial statements for a discussion of the impact on the full year financial statements.

Supplemental Natural Gas and Oil Operations (Unaudited)

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in the United States and Brazil. In the United States, we have onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. All of our proved reserves are in the United States and Brazil. We have excluded information relating to our natural gas and oil operations in Canada, Indonesia and Hungary from the following disclosures. We classified these operations as discontinued operations beginning in the second quarter of 2004 based on our decision to exit these operations.

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

	United States	Brazil	Worldwide
2004			
Natural gas and oil properties:			
Costs subject to amortization[1]	$14,211	$337	$14,548
Costs not subject to amortization	308	112	420
	14,519	449	14,968
Less accumulated depreciation, depletion and amortization	11,130	138	11,268
Net capitalized costs	$ 3,389	$311	$ 3,700
FAS143 abandonment liability	$ 252	$ 4	$ 256
2003			
Natural gas and oil properties:			
Costs subject to amortization[1]	$14,052	$146	$14,198
Costs not subject to amortization	371	117	488
	14,423	263	14,686
Less accumulated depreciation, depletion and amortization	11,216	58	11,274
Net capitalized costs	$ 3,207	$205	$ 3,412
FAS 143 abandonment liability	$ 210	$ —	$ 210

(1) As of January 1, 2003, we adopted SFAS No. 143, which is further discussed in Note 1. Included in our costs subject to amortization at December 31, 2004 and 2003 are SFAS No. 143 asset values of $154 million and $124 million for the United States and $3 million and $0.2 million for Brazil.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

	United States	Brazil	Worldwide
2004			
Property acquisition costs			
Proved properties	$ 33	$ 69	$ 102
Unproved properties	32	3	35
Exploration costs[1]	185	25	210
Development costs[1]	395	1	396
Costs expended in 2004	645	98	743
Asset retirement obligation costs	30	3	33
Total costs incurred	$ 675	$101	$ 776

	United States	Brazil	Worldwide
2003			
Property acquisition costs			
Proved properties	$ 10	$ —	$ 10
Unproved properties	35	4	39
Exploration costs[1]	467	95	562
Development costs[1]	668	—	668
Costs expended in 2003	1,180	99	1,279
Asset retirement obligation costs[2]	124	—	124
Total costs Incurred	$1,304	$ 99	$1,403
2002			
Property acquisition costs			
Proved properties	$ 362	$ —	$ 362
Unproved properties	29	9	38
Exploration costs	524	45	569
Development costs	1,242	—	1,242
Total costs incurred	$2,157	$ 54	$2,211

(1) Excludes approximately $110 million and $130 million that was paid in 2004 and 2003 under net profits agreements described beginning on page 178.

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. The cumulative effect of adopting SFAS No. 143 was $3 million.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $44 million, $58 million, and $76 million and capitalized interest of $22 million, $19 million and $10 million for the years ended December 31, 2004, 2003 and 2002.

In our January 1, 2005 reserve report, the amounts estimated to be spent in 2005, 2006 and 2007 to develop our worldwide booked proved undeveloped reserves are $182 million, $251 million and $218 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2004, pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2004	Costs Excluded for Years Ended December 31 2004	2003	2002	Cumulative Balance December 31, 2001
Worldwide[1][2]					
Acquisition	$209	$ 76	$ 51	$ 61	$21
Exploration	178	62	92	18	6
Development	33	1	3	27	2
	$420	$139	$146	$106	$29

(1) Includes operations in the United States and Brazil.

(2) Includes capitalized interest of $20 million, $6 million, and less than $1 million for the years ended December 31, 2004, 2003, and 2002.

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2005 through 2008. Our total amortization expense per Mcfe for the United States was $1.84, $1.40, and $1.05 in 2004, 2003, and 2002 and $2.02 for Brazil in 2004. We had no production in Brazil during 2003 and 2002. Included in our worldwide depreciation, depletion, and amortization expense is accretion expense of $0.08/Mcfe and $0.06/Mcfe for 2004 and 2003 attributable to SFAS No. 143 which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil, and condensate, and changes in these reserves at December 31, 2004 are presented below. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott was within four percent of our internally prepared estimates presented in these tables. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our proved properties based on value. The tables below exclude our Power segment's equity interest in Sengkang in Indonesia and Aguaytia in Peru. Combined proved reserves balances for these interests were 132,336 MMcf of natural gas and 2,195 MBbls of oil, condensate and NGL for total natural gas equivalents of 145,507 MMcfe, all net to our ownership interests.

	Natural Gas (in Bcf)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	2,799	—	2,799
Revisions of previous estimates	(155)	—	(155)
Extensions, discoveries and other	829	—	829
Purchases of reserves in place	142	—	142
Sales of reserves in place	(657)	—	(657)
Production	(470)	—	(470)
December 31, 2002	2,488	—	2,488
Revisions of previous estimates	(24)	—	(24)
Extensions, discoveries and other	405	—	405
Purchases of reserves in place	2	—	2
Sales of reserves in place[2]	(471)	—	(471)
Production	(339)	—	(339)
December 31, 2003	2,061	—	2,061
Revisions of previous estimates	(172)	—	(172)
Extensions, discoveries and other	79	38	117
Purchases of reserves in place	15	38	53
Sales of reserves in place[2]	(21)	—	(21)
Production	(238)	(7)	(245)
December 31, 2004	1,724	69	1,793
Proved developed reserves			
December 31, 2002	1,799	—	1,799
December 31, 2003	1,428	—	1,428
December 31, 2004	1,287	54	1,341

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 20,729 MMcf and 28,779 MMcf of natural gas conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page 178.

	Oil and Condensate (in MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	45,153	—	45,153
Revisions of previous estimates	1,552	—	1,552
Extensions, discoveries and other	7,921	—	7,921
Purchases of reserves in place	62	—	62
Sales of reserves in place	(3,754)	—	(3,754)
Production	(12,580)	—	(12,580)
December 31, 2002	38,354	—	38,354
Revisions of previous estimates	895	—	895
Extensions, discoveries and other	5,000	20,543	25,543
Purchases of reserves in place	5	—	5
Sales of reserves in place[2]	(4,328)	—	(4,328)
Production	(7,555)	—	(7,555)
December 31, 2003	32,371	20,543	52,914
Revisions of previous estimates	(999)	252	(747)
Extensions, discoveries and other	2,214	1,848	4,062
Purchases of reserves in place	—	1,848	1,848
Sales of reserves in place[2]	(1,276)	—	(1,276)
Production	(4,979)	(320)	(5,299)
December 31, 2004	27,331	24,171	51,502
Proved developed reserves			
December 31, 2002	28,554	—	28,554
December 31, 2003	22,821	—	22,821
December 31, 2004	19,641	2,613	22,254

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual agreements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 1,276 MBbl and 1,098 MBbl of liquids conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page 178.

	NGL (in MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves[1]			
January 1, 2002	28,874	—	28,874
Revisions of previous estimates	(2,289)	—	(2,289)
Extensions, discoveries and other	6,820	—	6,820
Purchases of reserves in place	—	—	—
Sales of reserves in place	(7,916)	—	(7,916)
Production	(3,882)	—	(3,882)
December 31, 2002	21,607	—	21,607
Revisions of previous estimates	(2,717)	—	(2,717)
Extensions, discoveries and other	1,795	—	1,795
Purchases of reserves in place	27	—	27
Sales of reserves in place[2]	(504)	—	(504)
Production	(4,223)	—	(4,223)
December 31, 2003	15,985	—	15,985
Revisions of previous estimates	724	—	724
Extensions, discoveries and other	58	—	58
Purchases of reserves in place	—	—	—
Sales of reserves in place[2]	(47)	—	(47)
Production	(3,519)	—	(3,519)
December 31, 2004	13,201	—	13,201
Proved developed reserves			
December 31, 2001	17,526	—	17,526
December 31, 2002	14,088	—	14,088
December 31, 2003	11,943	—	11,943

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual agreements and royalty obligations in effect at the time of the estimate.

(2) Sales of reserves in place include 47 MBbl and 194 MBbl of NGL conveyed to third parties under net profits agreements in 2004 and 2003 as described below.

During 2004, we had approximately 174 Bcfe of negative reserve revisions in the United States that were largely performance-driven. Our reserve revisions were primarily concentrated onshore in our coal bed methane operations and offshore in the Gulf of Mexico:

Onshore. The onshore region recorded 71 Bcfe of negative reserve revisions. All of the negative reserve revisions are related to performance results from producing wells or the recent drilling program coupled with the related impact on booked proven undeveloped locations. In certain areas of the Arkoma and Black Warrior Basins, wells drilled in late 2003 had positive initial results; however, subsequent drilling and additional production history resulted in 70 Bcfe of negative revisions. In the Holly Field of North Louisiana, 14 Bcfe of reserves were revised downward as a result of production performance. These negative revisions were offset by better-than-anticipated performance in the Rockies and other Arklatex fields, resulting in positive reserve revisions of 13 Bcfe.

Texas Gulf Coast. The Texas Gulf Coast region recorded 26 Bcfe of negative reserve revisions. The negative revisions were comprised of approximately 7 Bcfe of performance revisions to proved producing wells, approximately 6 Bcfe due to mechanical failures in five wells, and approximately 13 Bcfe due to lower-than-expected results from the 2004 development drilling program.

Offshore. The offshore region recorded 77 Bcfe of negative reserve revisions in the Gulf of Mexico. Approximately 10 Bcfe of the revisions is a result of mechanical failures, and approximately 25 Bcfe is due to producing well performance. The remaining 42 Bcfe resulted from the drilling of development wells and adjustments to proved undeveloped reserves as a result of production performance in offsetting locations.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2004. However in January 2005, we announced two acquisitions in east Texas and south Texas for $211 million. In March 2005, we acquired the interest of one of the parties in our net profits interest drilling program for $62 million. These acquisitions added properties with approximately 139 Bcfe of existing proved reserves and 52 MMcfe/d of current production.

In 2003, we entered into agreements to sell interests in a maximum of 124 wells to Lehman Brothers and a subsidiary of Nabors Industries. As these wells are developed, Lehman and Nabors will pay 70 percent of the drilling and development costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, Lehman and Nabors receive an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 70 percent of the aggregate net profits of all wells until they have recovered 117.5 percent of their aggregate investment. Upon this recovery, the net profits interest will convert to a 2 percent overriding royalty interest in the wells for the remainder of the well's productive life. We do not guarantee a return or the recovery of Lehman and Nabor's costs. All parties to the agreement have the right to cease participation in the agreement at any time, at which time Lehman or Nabors will continue to receive its net profits interest on wells previously started, but will relinquish its right to participate in any future wells. During 2004, we sold interests in 54 wells and total proved reserves of 20,729 MMcf of natural gas and 1,323 MBbl of oil and natural gas liquids. They have paid $110 million of drilling and development costs and were paid $152 million of the revenues net of $11 million of expenses associated with these wells for the year ended December 31, 2004. In March 2005, we acquired all of the interests held by the Lehman subsidiary for $62 million.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	United States	Brazil	Worldwide
2004			
Net Revenues			
Sales to external customers	$ 518	$27	$ 545
Affiliated sales	1,137	(1)	1,136
Total	1,655	26	1,681
Production costs[1]	(210)	—	(210)
Depreciation, depletion and amortization[2]	(530)	(18)	(548)
	915	8	923
Income tax (expense) benefit	(333)	(3)	(336)
Results of operations from producing activities	$ 582	$ 5	$ 587
2003			
Net Revenues			
Sales to external customers	$ 191	$—	$ 191
Affiliated sales	1,868	—	1,868
Total	2,059	—	2,059
Production costs[1]	(229)	—	(229)
Depreciation, depletion and amortization[2]	(576)	—	(576)
Ceiling test charges	—	(5)	(5)
	1,254	(5)	1,249
Income tax (expense) benefit	(449)	2	(447)
Results of operations from producing activities	$ 805	$(3)	$ 802
2002			
Net Revenues			
Sales to external customers	$ 134	$—	$ 134
Affiliated sales	1,677	—	1,677
Total	1,811	—	1,811
Production costs[1]	(284)	—	(284)
Depreciation, depletion and amortization	(599)	—	(599)
Gain on long-lived assets	2	—	2
	930	—	930
Income tax (expense) benefit	(327)	—	(327)
Results of operations from producing activities	$ 603	$—	$ 603

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

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. Our depreciation, depletion and amortization includes accretion expense for SFAS 143 abandonment liabilities of $23 million primarily for the United States for both 2004 and 2003.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves at December 31 is as follows (in millions):

	United States	Brazil	Worldwide
2004			
Future cash inflows[(1)]	$11,895	$1,077	$12,972
Future production costs	(3,585)	(135)	(3,720)
Future development costs	(1,234)	(274)	(1,508)
Future income tax expenses	(1,184)	(141)	(1,325)
Future net cash flows	5,892	527	6,419
10% annual discount for estimated timing of cash flows	(2,004)	(219)	(2,223)
Standardized measure of discounted future net cash flows	$ 3,888	$ 308	$ 4,196
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 3,907	$ 305	$ 4,212
2003			
Future cash inflows[(1)]	$13,302	$ 588	$13,890
Future production costs	(3,025)	(65)	(3,090)
Future development costs	(1,325)	(236)	(1,561)
Future income tax expenses	(1,695)	(75)	(1,770)
Future net cash flows	7,257	212	7,469
10% annual discount for estimated timing of cash flows	(2,449)	(128)	(2,577)
Standardized measure of discounted future net cash flows	$ 4,808	$ 84	$ 4,892
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,759	$ 84	$ 4,843
2002			
Future cash inflows[(1)]	$12,847	$ —	$12,847
Future production costs	(2,924)	—	(2,924)
Future development costs	(1,361)	—	(1,361)
Future income tax expenses	(1,960)	—	(1,960)
Future net cash flows	6,602	—	6,602
10% annual discount for estimated timing of cash flows	(2,293)	—	(2,293)
Standardized measure of discounted future net cash flows	$ 4,309	$ —	$ 4,309
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,266	$ —	$ 4,266

(1) United States excludes $1 million, $104 million and $85 million of future net cash outflows attributable to hedging activities in the years 2004, 2003 and 2002. Brazil excludes $5 million of future net cash outflows attributable to hedging activities in 2004.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $6.22 per MMbtu for natural gas and $43.45 per barrel of oil at December 31, 2004. Adjustments for transportation and other charges resulted in a net price of $5.99 per Mcf of gas, $42.11 per barrel of oil and $32.13 per barrel of NGL at December 31, 2004. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions, capital availability, and corporate investment criteria.

The following are the principal sources of change in the worldwide standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,[1],[2]		
	2004	2003	2002
		(In Millions)	
Sales and transfers of natural gas and oil produced net of production costs	$(1,470)	$(1,829)	$(1,526)
Net changes in prices and production costs	29	1,586	3,301
Extensions, discoveries and improved recovery, less related costs	268	1,105	1,561
Changes in estimated future development costs	4	(16)	17
Previously estimated development costs incurred during the period	156	220	275
Revision of previous quantity estimates	(453)	(94)	(348)
Accretion of discount	568	526	275
Net change in income taxes	257	159	(934)
Purchases of reserves in place	114	5	284
Sale of reserves in place	(75)	(1,229)	(1,418)
Change in production rates, timing and other	(94)	150	93
Net change	$ (696)	$ 583	$ 1,580

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

(2) Includes operations in the United States and Brazil.

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2004, 2003 and 2002
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2004					
Allowance for doubtful accounts	$ 273	$(48)	$ (22)[1]	$ (4)	$ 199
Valuation allowance on deferred tax assets	9	46[3]	(4)	—	51
Legal reserves	1,169	145	(655)[5]	(67)	592
Environmental reserves	412	17	(51)[5]	2	380
Regulatory reserves	13	—	(12)[5]	—	1
2003					
Allowance for doubtful accounts	$ 176	$ 18	$ (31)[1]	$ 110[2]	$ 273
Valuation allowance on deferred tax assets	72	4	(68)[3]	1	9
Legal reserves	1,031	180[4]	(43)[5]	1	1,169
Environmental reserves	389	8	(52)[5]	67[6]	412
Regulatory reserves	24	32	(43)[5]	—	13
2002					
Allowance for doubtful accounts	$ 117	$ 30	$ (14)[1]	$ 43[2]	$ 176
Valuation allowance on deferred tax assets	28	46[3]	(2)	—	72
Legal reserves	149	954[4]	(74)[5]	2	1,031
Environmental reserves	468	(3)	(63)	(13)	389
Regulatory reserves	34	48	(59)[5]	1	24

(1) Relates primarily to accounts written off.

(2) Relates primarily to receivables from trading counterparties, reclassified due to bankruptcy or declining credit that have been accounted for within our price risk management activities.

(3) Relates primarily to valuation allowances for deferred tax assets related to the Western Energy Settlement, foreign ceiling test charges, foreign asset impairments and net operating loss carryovers.

(4) Relates to our Western Energy Settlement of $104 million in 2003 and $899 million in 2002. In June 2004, we released approximately $602 million to the settling parties (including approximately $568 million from escrow) and correspondingly reduced our liability by this amount.

(5) Relates primarily to payments for various litigation reserves, including the Western Energy Settlement, environmental remediation reserves or revenue crediting and rate settlement reserves.

(6) Relates primarily to liabilities previously classified in our petroleum discontinued operations, but reclassified as continuing operations due to our retention of these obligations.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of this report:

1. Financial statements.

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

* Previously filed with our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2004

Each exhibit identified below is filed as part of this report. Exhibits not incorporated by reference to a prior filing or previously filed are designated by an "*"; exhibits previously filed with our Annual Report on Form 10-K for the fiscal year ended December 31, 2004 are designated by an "**"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

2.A	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (including the form of Assumption Agreement to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.1 to our Form 8-K filed December 15, 2003)
2.B	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the form of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.2 to our Form 8-K filed December 15, 2003); Amendment No. 1 to Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company, dated as of April 19, 2004 (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (Exhibit 2.1 to our Form 8-K filed April 21, 2004); Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003 (Exhibit 2.3 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (Exhibit 2.4 to our Form 8-K filed December 15, 2003)
**2.B.1	Purchase and Sale Agreement, dated as of January 14, 2005, by and among Enterprise GP Holdings, L.P., Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso Corporation and GulfTerra GP Holding Company
3.A	Restated Certificate of Incorporation effective as of August 11, 2003 (Exhibit 3.A to our 2003 Second Quarter Form 10-Q)
3.B	By-Laws effective as of July 31, 2003 (Exhibit 3.B to our 2003 Second Quarter Form 10-Q)
**4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA (successor to JPMorgan Chase Bank, formerly The Chase Manhattan Bank), as Trustee

10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004); Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004)
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004)
10.C	$3,000,000,00 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.1 to our Form 8-K filed April 18, 2003); First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 17, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lender and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 Form 10-K); Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Form 10-K); Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 99.B to our Form 8-K filed August 10, 2004)
10.D	$1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.2 to our Form 8-K filed April 18, 2003)

10.E	Security and Intercreditor Agreement dated as of April 16, 2003 Among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to our Form 8-K filed April 18, 2003)
+10.F	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our 2003 Form 10-K)
**+10.G	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999
**+10.G.1	Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors
+10.G.2	Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q)
+10.H	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.H.1 to our 2003 Form 10-K)
**+10.I	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998
**+10.I.1	Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan
**+10.I.2	Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan
+10.J	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.I.1 to our 2003 Second Quarter Form 10-Q)
+10.K	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.K.1 to our 2003 Form 10-K)
+10.L	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.K to our 2001 Form 10-K); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.K.1 to our 2002 Form 10-K); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q)
**+10.L.1	Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan
**+10.M	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998
+10.M.1	Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.L.1 to our 2002 Form 10-K)

**+10.N	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998
+10.N.1	Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2003 Third Quarter Form 10-Q)
+10.O	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K)
**+10.P	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998
+10.P.1	Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our 2003 Form 10-K)
+10.Q	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.P.1 to our 2002 Form 10-K)
**+10.R	Domestic Relocation Policy effective November 1, 1996
**+10.S	Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999
+10.S.1	Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q)
+10.T	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed February 11, 2002); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.T.1 to our 2002 Form 10-K)
+10.U	El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q); Amendment No. 1 effective as of June 6, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.AA.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.V.1 to our 2003 Form 10-K)

+10.V	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Amendment No. 2 to Supplement No. 1 effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 3 to Supplement No. 1 effective as of September 2, 2003 (Exhibit 10.Z.1 to our 2003 Third Quarter Form 10-Q); Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003 (Exhibit 10.W.1 to our 2003 Form 10-K); Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004 (Exhibit 10.W.1 to our 2003 Form 10-K)
+10.W	Employment Agreement Amended and Restated effective as of February 1, 2001 between El Paso and William A. Wise (Exhibit 10.0 to our 2000 Form 10-K)
+10.X	Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott. (Exhibit 10.VV to our 2004 Third Quarter Form 10-Q)
+10.Y	Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.U to our 2003 Third Quarter Form 10-Q)
+10.Y.1	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K)
+10.Z	Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart (Exhibit 10.CC to our 2003 Form 10-K)
+10.AA	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.FF to our 2002 Form 10-K)
+10.BB	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective December 17, 2004 (Exhibit 10.WW to our 2003 Third Quarter Form 10-Q)
+10.CC	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2003 Third Quarter Form 10-Q)
10.DD	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to our 2003 Second Quarter Form 10-Q)

10.EE	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our 2003 Form 10-K)
10.FF	Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles (Exhibit 10.II to our 2003 Second Quarter Form 10-Q)
10.GG	Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004, and terminated as described in our Form 8-K filed December 3, 2004)
**21	Subsidiaries of El Paso
*23.A	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Houston)
**23.B	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Detroit)
**23.C	Consent of Ryder Scott Company, L.P.
*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 Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 6th day of May 2005.

EL PASO CORPORATION
Registrant

By /s/ DOUGLAS L. FOSHEE
Douglas L. Foshee
President and Chief Executive Officer

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

Signature	Title	Date
/s/ DOUGLAS L. FOSHEE (Douglas L. Foshee)	President, Chief Executive Officer and Director (Principal Executive Officer)	May 6, 2005
/s/ D. DWIGHT SCOTT (D. Dwight Scott)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	May 6, 2005
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	May 6, 2005
/s/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Chairman of the Board and Director	May 6, 2005
/s/ JOHN M. BISSELL (John M. Bissell)	Director	May 6, 2005
/s/ JUAN CARLOS BRANIFF (Juan Carlos Braniff)	Director	May 6, 2005
/s/ JAMES L. DUNLAP (James L. Dunlap)	Director	May 6, 2005
/s/ ROBERT W. GOLDMAN (Robert W. Goldman)	Director	May 6, 2005
/s/ ANTHONY W. HALL, JR. (Anthony W. Hall, Jr.)	Director	May 6, 2005

Signature	Title	Date
/s/ THOMAS R. HIX (Thomas R. Hix)	Director	May 6, 2005
/s/ WILLIAM H. JOYCE (William H. Joyce)	Director	May 6, 2005
/s/ J. MICHAEL TALBERT (J. Michael Talbert)	Director	May 6, 2005
/s/ JOHN L. WHITMIRE (John L. Whitmire)	Director	May 6, 2005
/s/ JOE B. WYATT (Joe B. Wyatt)	Director	May 6, 2005