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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2002

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 1-9864

El Paso Tennessee Pipeline Co.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**76-0233548**
(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**

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

Common Stock, par value $0.01 per share. Shares outstanding on August 14, 2002: 1,971

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO TENNESSEE PIPELINE CO.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Operating revenues	$ 290	$ 798	$ 1,016	$ 1,835
Operating expenses				
Cost of products and services	33	316	353	732
Operation and maintenance	190	179	429	372
Restructuring and merger-related costs and asset impairments	12	43	354	72
Depreciation, depletion and amortization	55	52	115	126
Taxes, other than income taxes	23	18	45	42
	313	608	1,296	1,344
Operating income (loss)	(23)	190	(280)	491
Other income				
Earnings from unconsolidated affiliates	76	36	80	57
Other, net	21	50	31	74
	97	86	111	131
Income (loss) before interest, income taxes and other charges	74	276	(169)	622
Non-affiliated interest and debt expense	32	37	71	78
Affiliated interest expense, net	25	44	43	109
Minority interest	6	—	12	—
Income taxes	3	75	(99)	147
	66	156	27	334
Income (loss) before extraordinary items and cumulative effect of accounting change	8	120	(196)	288
Extraordinary items, net of income taxes	—	38	—	38
Cumulative effect of accounting change, net of income taxes	—	—	97	—
Net income (loss)	$ 8	$ 158	$ (99)	$ 326

See accompanying notes.

EL PASO TENNESSEE PIPELINE CO.

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

	June 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 125	$ 197
Accounts and notes receivable, net		
Customer	3,140	2,723
Affiliates	379	271
Other	430	600
Inventory	37	79
Assets from price risk management activities	1,587	2,529
Margin deposits on energy trading activities	714	379
Other	395	318
Total current assets	6,807	7,096
Property, plant and equipment, at cost		
Pipelines	2,895	2,824
Gathering and processing systems	919	2,199
Power facilities	595	563
Other	99	99
	4,508	5,685
Less accumulated depreciation, depletion and amortization	964	1,040
	3,544	4,645
Additional acquisition costs assigned to utility plant, net	2,254	2,271
Total property, plant and equipment, net	5,798	6,916
Other assets		
Notes receivable from unconsolidated affiliates	276	295
Investments in unconsolidated affiliates	2,385	2,825
Assets from price risk management activities	2,583	2,156
Other	623	707
	5,867	5,983
Total assets	$18,472	$19,995

See accompanying notes.

EL PASO TENNESSEE PIPELINE CO.

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

	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 3,171	$ 2,927
Affiliates	398	533
Other	135	308
Short-term borrowings and other financing obligations	445	567
Notes payable to unconsolidated affiliates	2,612	2,399
Liabilities from price risk management activities	1,656	2,089
Margin deposits from customers on energy trading activities	11	649
Other	500	557
Total current liabilities	8,928	10,029
Long-term debt and other financing obligations	1,688	1,563
Other liabilities		
Liabilities from price risk management activities	1,462	1,236
Deferred income taxes	1,765	1,971
Other	887	996
	4,114	4,203
Commitments and contingencies		
Minority interests	355	356
Stockholders' equity		
Preferred stock, authorized; 20,000,000 shares Series A, no par; issued 6,000,000 shares; stated at liquidation value	300	300
Common stock, par value $0.01 per share; authorized 100,000 shares; issued 1,971 shares	—	—
Additional paid-in capital	1,992	1,973
Retained earnings	1,199	1,641
Accumulated other comprehensive income (loss)	(104)	(70)
Total stockholders' equity	3,387	3,844
Total liabilities and stockholders' equity	$18,472	$19,995

See accompanying notes.

EL PASO TENNESSEE PIPELINE CO.

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

	Six Months Ended June 30,	
	2002	**2001**
Cash flows from operating activities		
Net income (loss)	$ (99)	$ 326
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(38)	(347)
Non-cash portion of merger-related costs and asset impairments	342	38
Depreciation, depletion and amortization	115	126
Undistributed earnings of unconsolidated affiliates	(48)	(10)
Deferred income tax expense (benefit)	(121)	160
Extraordinary items	—	(59)
Cumulative effect of accounting change	(97)	—
Other non-cash income items	42	(11)
Working capital changes	(581)	3,115
Non-working capital changes and other	(18)	(146)
Net cash provided by (used in) operating activities	(503)	3,192
Cash flows from investing activities		
Additions to property, plant and equipment	(195)	(252)
Net proceeds from the sale of assets	275	246
Additions to investments	(20)	(219)
Net proceeds from investments	29	5
Cash deposited in escrow	(84)	(133)
Return of cash deposited in escrow	11	—
Net change in other affiliated advances receivable	94	—
Repayment of notes receivable from unconsolidated affiliates	13	13
Other	1	—
Net cash provided by (used in) investing activities	124	(340)
Cash flows from financing activities		
Net repayments of commercial paper	(61)	(47)
Payments to retire long-term debt	(2)	(364)
Net proceeds from the issuance of long-term debt	238	—
Net change in other affiliated advances payable	214	(2,406)
Repayment of notes payable	(11)	—
Decrease in notes payable to unconsolidated affiliates	—	(9)
Dividends paid	(71)	(12)
Net cash provided by (used in) financing activities	307	(2,838)
Increase (decrease) in cash and cash equivalents	(72)	14
Cash and cash equivalents		
Beginning of period	197	179
End of period	$ 125	$ 193

See accompanying notes.

EL PASO TENNESSEE PIPELINE CO.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Net income (loss)	$ 8	$158	$ (99)	$ 326
Foreign currency translation adjustments	4	(12)	4	(20)
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $66)	—	—	—	(154)
Unrealized mark-to-market losses arising during period (net of tax of $25 and $28 in 2002 and $84 and $61 in 2001)	(32)	195	(41)	(88)
Reclassification adjustments for changes in initial value to settlement date (net of tax of $10 and $6 in 2002 and $71 and $132 in 2001)	11	110	3	226
Other comprehensive income (loss)	(17)	293	(34)	(36)
Comprehensive income (loss)	$ (9)	$451	$(133)	$ 290

See accompanying notes.

EL PASO TENNESSEE PIPELINE CO.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2001 Annual Report on Form 10-K which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2002, and for the quarters and six months ended June 30, 2002 and 2001, are unaudited. We derived the balance sheet as of December 31, 2001, from the audited balance sheet filed in our Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for the items discussed below and in Notes 3 and 4), to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not indicate the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or stockholders' equity.

Our accounting policies are consistent with those discussed in our Form 10-K, except as discussed below:

Goodwill and Other Intangible Assets

Our intangible assets consist primarily of goodwill resulting from acquisitions. On January 1, 2002, we adopted Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets.* These standards required that we recognize goodwill separately from other intangible assets. In addition, goodwill and indefinite-lived intangibles are no longer amortized. Instead, goodwill is periodically tested for impairment, at least on an annual basis, or whenever an event occurs that indicates that an impairment may have occurred. SFAS No. 141 requires that any negative goodwill should be written off as a cumulative effect of an accounting change. Prior to adoption of these standards, we amortized goodwill and other intangibles using the straight-line method over periods ranging from 5 to 40 years. As a result of our adoption of these standards on January 1, 2002, we stopped amortizing goodwill, and recognized a pretax and after-tax gain of $97 million related to the write-off of negative goodwill. We have reported this gain as a cumulative effect of an accounting change in our income statement.

We completed our initial periodic impairment tests during the first quarter of 2002, and concluded that we did not have any adjustment to our goodwill. Amortization of goodwill and negative goodwill would have been approximately $2 million and $4 million, net of income taxes, for the quarter and six months ended June 30, 2002 had we not adopted these standards. In addition, had we applied the amortization provisions of SFAS No. 141 and 142 on January 1, 2001, we would have reported net income of $160 million and $330 million for the quarter and six months ended June 30, 2001.

Asset Impairments

On January 1, 2002, we adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 changed the accounting requirements related to when an asset qualifies as held for sale or as a discontinued operation and the way in which we evaluate impairments of assets. It also changes accounting for discontinued operations such that we can no longer accrue future operating losses in these operations. There was no initial financial statement impact of adopting this statement.

Price Risk Management Activities

In the second quarter of 2002, we adopted Derivatives Implementation Group (DIG) Issue No. C-15, *Scope Exceptions: Normal Purchases and Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*. DIG Issue C-15 requires that if an electric power contract includes terms that are based upon market factors that are not related to the actual costs to generate the power, the contract is a derivative that must be recorded at its fair value. An example is a power sales contract at a natural gas-fired power plant that has pricing indexed to the price of coal. Our adoption of these rules did not have a material effect on our financial statements. The accounting for electric power contracts as derivatives was not clearly addressed when SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, was adopted in January 2001. DIG Issue No. C-15 and other DIG issues have attempted to resolve inconsistencies in the accounting for power contracts, and we believe the rules will continue to evolve. It is possible that our accounting for these contracts may change as new guidance is issued and existing rules are applied and interpreted.

In the second quarter of 2002, we adopted 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 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. There was no initial financial statement impact of adopting this standard.

In June 2002, the Emerging Issues Task Force (EITF) reached a consensus in EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, requiring that all mark-to-market gains and losses related to energy trading contracts, including physical settlements, be recorded in the income statement on a net basis instead of being reported on a gross basis as revenues for physically settled sales and expenses for physically settled purchases. We elected to adopt this consensus issue in the second quarter, and now report our trading activity on a net basis as a component of revenues. We have also applied this guidance to all prior periods, which had no impact on previously reported net income or stockholders' equity. Revenues and costs that have been netted as a result of adopting this consensus were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Gross operating revenues	$ 9,158	$ 8,314	$ 17,431	$ 18,496
Costs reclassified	(8,868)	(7,516)	(16,415)	(16,661)
Net operating revenues reported in the income statement	$ 290	$ 798	$ 1,016	$ 1,835

The EITF continues to evaluate disclosure and valuation issues in its continuing deliberations on Issue No. 02-3, and we will monitor and assess the impact of adopting these issues when and if a consensus is reached.

2. Divestitures

In March 2001, we sold natural gas liquids transportation and fractionation assets acquired in our December 2000 acquisition of Pacific Gas & Electric's (PG&E's) midstream operations to our affiliate, El Paso Energy Partners, L.P., a publicly traded master limited partnership, for approximately $133 million.

In April 2002, we sold midstream assets for approximately $265 million to one of our affiliates, El Paso Energy Partners. Net proceeds from this sale were approximately $259 million in cash, and common units of El Paso Energy Partners with a fair value of $6 million. No gain or loss was recognized on this sale.

In July 2002, our parent entered into a letter of intent with El Paso Energy Partners to sell our onshore and offshore natural gas and oil gathering systems, natural gas liquids transportation and fractionation assets. We stopped depreciating these assets beginning in July 2002 since these assets are held for sale.

3. Restructuring and Merger-Related Costs and Asset Impairments

Our organizational restructuring and merger-related costs and asset impairments for the periods ended June 30 consisted of the following:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Restructuring costs	$12	$—	$ 12	$—
Merger-related costs	—	5	—	34
Asset impairments	—	38	342	38
Total	$12	$43	$354	$72

Restructuring Costs

In December 2001, El Paso Corporation (El Paso), our parent, announced a plan to strengthen its balance sheet, reduce costs and focus its activities on its core natural gas businesses. In May 2002, we completed an employee restructuring across all our operating segments which resulted in a reduction of approximately 208 full-time positions through terminations. In connection with this, we incurred $12 million of employee severance and termination costs. As of June 30, 2002, we had paid $7 million of this charge, and the remainder will be paid in the third quarter of 2002. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans.

Merger-related Costs

During the periods ended June 30, 2001, we incurred merger-related costs associated with El Paso merger with The Coastal Corporation as follows:

	Quarter Ended June 30, 2001	Six Months Ended June 30, 2001
	(In millions)	
Employee severance, retention and transition costs	$ 1	$ 5
Make-whole commitments	4	25
Other	—	4
	$ 5	$34

Employee severance, retention and transition costs include direct payments to, and benefit costs for, terminated employees and early retirees that occurred as a result of El Paso's merger-related workforce reduction and consolidation. The amount of employee severance, retention and transaction costs paid and charged against the accrued amount for the six months ended June 30, 2001 was approximately $5 million. Make-whole commitments relate to a series of payments we will make to El Paso Energy Partners in connection with the Federal Trade Commission's (FTC) ordered divestiture of interests in assets owned by the partnership.

Asset Impairments

During the first quarter of 2002, we recognized an asset impairment charge in our Merchant Energy segment of $342 million related to our investments in Argentina. During the latter part of 2001, economic conditions in Argentina deteriorated, and the Argentine government defaulted on its public debt obligations. In the first quarter of 2002, the government changed several Argentine laws, including: (i) repealing the one-to-one exchange rate for the Argentine Peso with U.S. dollar; (ii) mandating that all Argentine contracts and obligations previously denominated in U.S. dollars be re-negotiated and denominated in Argentine Pesos; and (iii) imposing a tax on crude oil exports. The Argentine Peso devaluation combined with these new law changes effectively converted our projects' contracts and sources of revenue from U.S. dollars to Argentine Pesos and resulted in the impairment charge, which represents the full amount of each of the investments impacted by these law changes. We have a remaining investment in a pipeline project in Argentina with an aggregate investment of approximately $39 million. Should these conditions persist, or if new unfavorable developments occur, we may also be required to evaluate our remaining investment for impairment. We continue to monitor the situation closely, including our rights and remedies under applicable law, treaties and political risk policies arising from the emergency measures taken in Argentina.

During the second quarter of 2001, we incurred an asset impairment charge of $38 million resulting from Merchant Energy's impairment of its East Asia Power investment in the Philippines. This write-down was a result of weak economic conditions causing a permanent decline in the value of our investment. We continue to hold this investment.

4. Extraordinary Items

As a result of El Paso's merger with Coastal in January 2001, we were required by the FTC to sell our Midwestern Gas Transmission system. We completed this sale in April 2001. Net proceeds were approximately $95 million, and we recognized an extraordinary gain of $38 million, net of income taxes of $21 million.

5. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of June 30, 2002 and December 31, 2001:

	June 30, 2002	December 31, 2001
	(In millions)	
Net assets[1]		
Trading contracts[2]	$1,051	$1,337
Non-trading contracts	1	23
	$1,052	$1,360

[1] We do not recognize gains on the fair value of trading or non-trading positions beyond ten years unless there is clearly demonstrated liquidity in a specific market.

[2] Trading contracts represent those that qualify for accounting under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.*

6. Inventory

Our inventory consisted of the following:

	June 30, 2002	December 31, 2001
	(In millions)	
Materials and supplies and other	$36	$38
Natural gas in storage	1	41
	$37	$79

7. Debt and Other Credit Facilities

At June 30, 2002, our weighted average interest rate on our commercial paper and short-term borrowings was 2.6% and at December 31, 2001, it was 3.2%. We had the following short-term borrowings and other financing obligations:

	June 30, 2002	December 31, 2001
	(In millions)	
Commercial paper	$363	$424
Notes payable	64	75
Current maturities of long-term debt and other financing obligations	18	68
	$445	$567

During the first quarter of 2002, we distributed several of our midstream business entities which had $180 million of long-term debt to El Paso.

In May 2002, El Paso renewed its $3 billion, 364-day revolving credit and competitive advance facility. Tennessee Gas Pipeline Company (TGP), our subsidiary, remains a designated borrower under this facility and, as such, is liable for any amounts outstanding under this facility. This facility matures in May 2003. In June 2002, El Paso amended its existing $1 billion, 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003, and TGP is a designated borrower under this facility and, as such, is liable for any amounts outstanding under this facility. The interest rate under both of these facilities varies based on El Paso's senior unsecured debt rating, and as of June 30, 2002, an initial draw would have had a rate of LIBOR plus 0.625%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts. As of June 30, 2002, there were no borrowings outstanding, and $450 million in letters of credit were issued under the $1 billion facility.

In June 2002, TGP issued $240 million aggregate principal amount 8.375% notes due 2032. Proceeds were approximately $238 million, net of issuance costs. As a result, TGP has no remaining capacity under its shelf registration statement on file with the SEC.

8. Commitments and Contingencies

Legal Proceedings

Several of our subsidiaries and affiliates were named defendants in eleven purported class action, municipal or individual lawsuits, filed in California state courts (a list of the *California* cases is included in Part II, Item 1, Legal Proceedings). The eleven suits contend that El Paso entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. The lawsuits have been consolidated before a single judge and are at the preliminary pleading stages, with trial not anticipated until late 2003 at the earliest.

In September 2001, we received a civil document subpoena from the California Department of Justice, seeking information said to be relevant to the Department's ongoing investigation into the high electricity prices in California. We have produced and expect to continue to produce materials under this subpoena.

In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. 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). In May 2001, the court denied the defendants' motions to dismiss.

A number of our subsidiaries were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

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.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of June 30, 2002, we had reserves totaling $26 million for all outstanding legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. As new information becomes available or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations.

Environmental Matters

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2002, we had a reserve of approximately $118 million for expected remediation costs (including related environmental litigation). In addition, we expect to make capital expenditures for environmental matters of approximately $69 million in the aggregate for the years 2002 through 2007. These expenditures primarily relate to compliance with clean air regulations.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (EPA) List of Hazardous Substances, 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, to ensure that its efforts meet regulatory requirements. 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 the Pennsylvania and New York stations.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the complaint and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under the 1994 consent order with the EPA. Despite these remediation efforts, the agency may raise additional technical issues or require additional remediation work in the future.

In May 1995, following negotiations with its customers, TGP filed an agreement with the Federal Energy Regulatory Commission (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 costs under the PCB remediation project, with these surcharges to be collected over a defined collection period. TGP has twice received approval from the FERC to extend the collection period, which is now currently set to expire in June 2004. The agreement also provided for bi-annual audits of eligible costs. As of June 30, 2002, TGP has over-collected PCB costs by approximately $113 million for which it has established a non-current liability. The over-collection will be reduced by future eligible costs incurred for the remainder of the remediation project. TGP is required to refund to its customers the over-collection amount to the extent actual eligible expenditures are less than amounts collected. Presently, TGP estimates the future refund obligation, at the conclusion of the remediation process, to be approximately $50 million.

We have been designated and 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 6 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 CERCLA sites, as appropriate, through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of June 30, 2002, we have estimated our share of the remediation costs at these sites to be between $1 million and $2 million and have provided reserves that we believe are adequate for such costs. 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 the determining of our estimated liabilities.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. 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 new information becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations. For a further discussion of specific environmental matters, see *Legal Proceedings* above.

Rates and Regulatory Matters

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with the FERC alleging that the sale of approximately 1.2 billion cubic feet per day of California capacity by El Paso Natural Gas Company (EPNG), our affiliate, to El Paso Merchant Energy Company, our subsidiary, was anticompetitive and an abuse of the affiliate relationship under the FERC's policies. Other parties in the proceeding requested that Merchant Energy pay back any profits it earned under the contract. In March 2001, the FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or Merchant Energy had market power and, if so, had exercised it. In October 2001, a FERC administrative law judge issued a proposed decision finding that El Paso did not exercise market power and that the market power portion of the CPUC's complaint should be dismissed. However, the decision did find that El Paso had violated the FERC's marketing affiliate regulations. In October 2001, the Market Oversight and Enforcement section of the FERC's Office of the General Counsel filed comments in this proceeding stating that record development at the trial was inadequate to conclude that EPNG and Merchant Energy complied with the FERC's regulations. In December 2001, the FERC remanded the proceeding to the administrative law judge for a supplemental hearing on the availability of EPNG's pipeline capacity. The hearing commenced on March 21, 2002, and concluded on April 4, 2002. Oral arguments were held on April 10, 2002. A post-hearing briefing was completed on June 5, 2002, and an administrative law judge's ruling is expected soon.

In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held on May 21, 2002, at which interested parties were given an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by El Paso's pipelines and others. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

On July 17, 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its policy, established in 1996, of permitting pipelines to enter into negotiated rate transactions. Our pipeline has entered into these transactions over the years, and the FERC is now undertaking a review of whether negotiated rates should be capped, whether or not a pipeline's "recourse rate" (its cost of service based rate) continues to serve as a viable alternative and safeguard against the exercise of alleged pipeline market power, as well as other issues related to its negotiated rate program. Comments are due on September 25, 2002, with reply comments due on October 25, 2002. We cannot predict the outcome of this NOI.

On August 1, 2002, the FERC issued a NOPR requiring that all arrangements concerning the cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent must maintain investment grade credit ratings. Comments on the NOPR are due on August 22, 2002. We cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued, to be effective immediately, an Accounting Release providing guidance on how jurisdictional entities should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. The Accounting Release sets forth the documentation requirements set forth in the NOPR for money pool arrangements, but does not address the requirements in the NOPR that as a condition for participating in money pool arrangements the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent must have investment grade credit ratings. Requests for rehearing are due on September 3, 2002.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels of rates for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment, including financial guarantees, of approximately $198 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The appeal was heard at the Western Australia Supreme Court in November 2001, and a decision from the court is expected in the second half of 2002. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity and debt capacity, possibly reducing the value of our investment by up to $138 million. Additionally, EPIC Energy (WA) Nominees Pty. Ltd. has debt of approximately AUD$1.8 billion (U.S.$1 billion) maturing in March 2003. Possible delays in the timing of the Supreme Court decision and uncertainty of the future rates may impact this refinancing.

El Paso Merchant Energy L.P. (EPME), our subsidiary, responded on May 22, 2002 to the FERC's May 8, 2002 request for statements of admission or denial with respect to trading strategies designed to manipulate California power markets. EPME provided an affidavit stating that it had not engaged in these trading strategies.

On May 21 and 22, 2002, the FERC issued additional data requests, including requests for statements of admission or denial with respect to so-called "wash" or "round trip" trades in western power and gas markets. In May and June 2002, EPME responded, denying that it had conducted any wash or round trip trades, (i.e., simultaneous, prearranged trades entered into for the purpose of artificially inflating trading volumes or revenues, or manipulating prices.)

On June 7, 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 on July 15, 2002. On July 12, 2002, we received a grand jury subpoena for documents concerning round trip or wash trades. We are conducting due diligence and plan to cooperate fully with these requests.

While the outcome of our rates and regulatory matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. As new information becomes available or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations.

Other Commercial Commitments

In 2001, we entered into agreements to time-charter four separate ships to secure transportation for our developing liquefied natural gas business. In May 2002, we entered into amendments to three of the initial four time charters to reconfigure the ships with onboard regasification technology and to secure an option for an additional time charter for a fifth ship. The exercise of the option for the fifth ship will represent a commitment of $522 million over the term of such charter. However, we are obligated to pay a termination fee of $24 million in the event the option is not exercised by April 2003. The agreements provide for deliveries of vessels between 2003 and 2005. Each time charter has a twenty-year term commencing when the vessels are delivered with the possibility of two five-year extensions. The total commitment under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. We are party to an agreement with an unaffiliated global integrated oil and gas company under which the third party agrees to bear 50 percent of the risk incidental to the initial $1.8 billion commitment made for the first four time charters.

Other Matters

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We, through our subsidiaries, had contracts with Enron North America and Enron Power Marketing for the trading of physical gas, power, petroleum and financial derivatives and for transportation capacity on our pipeline systems. We established reserves for potential losses related to the receivables from our transportation contracts that we believe are adequate. In addition, we have terminated most of our trading-related contracts, and Enron has rejected many of its capacity contracts on our pipeline systems. We believe our termination of the trading contracts was proper and in accordance with the terms of these contracts. We, like other creditors, are discussing with Enron the extent of our damage claims against various Enron entities.

As a result of current circumstances surrounding the energy sector, the creditworthiness of several industry participants has been called into question. We have taken actions to mitigate our exposure to these participants; however, should several of these participants file for Chapter 11 bankruptcy protection and our contracts are not assumed by other counterparties, it could have a material adverse effect on our financial position, operating results or cash flows.

We have investments in power, pipeline and production projects in Brazil. During the second quarter of 2002, Brazil experienced a significant decline in its financial markets due largely to concerns over the refinancing of Brazil's foreign debt and the upcoming presidential election. These concerns have contributed to higher interest rates on local debt for the government and private sectors, have significantly decreased the availability of funds from lenders outside of Brazil and have decreased the amount of foreign investment in the country. These factors have contributed to a downgrade of Brazil's foreign currency debt rating and a 22% devaluation of the local currency against the U.S. dollar during the second quarter of 2002. These developments are likely to delay the implementation of project financings underway in Brazil. The International Monetary Fund recently announced a $30 billion loan package for Brazil, however the release of the majority of the money will depend on Brazil committing to specified fiscal targets in 2003. We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our financial position, results of operations or cash flows. However, we will continue to monitor the economic situation, and it is possible that future developments in Brazil could cause us to reassess our exposure.

9. Segment Information

We segregate our business activities into three distinct operating segments: Pipelines, Merchant Energy and Field Services. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. We measure segment performance using earnings before interest and income taxes (EBIT). The following are our segment results as of and for the periods ended June 30:

	Quarter Ended June 30, 2002				
	Pipelines	Merchant Energy	Field Services	Other[1]	Total
	(In millions)				
Revenues from external customers	$ 147	$ 84 [2]	$ 59	$ —	$ 290
Intersegment revenues	19	(27) [2]	15	(7)	—
Restructuring costs	—	11	1	—	12
Operating income (loss)	59	(73)	11	(20)	(23)
EBIT	66	(1)	17	(8)	74

	Quarter Ended June 30, 2001				
	Pipelines	Merchant Energy	Field Services	Other[1]	Total
	(In millions)				
Revenues from external customers	$151	$ 298 [2]	$348	$ 1	$ 798
Intersegment revenues	19	(75) [2]	61	(5)	—
Merger-related costs and asset impairments	—	39	4	—	43
Operating income	65	92	25	8	190
EBIT	72	176	20	8	276

	Six Months Ended June 30, 2002				
	Pipelines	Merchant Energy	Field Services	Other[1]	Total
	(In millions)				
Revenues from external customers	$315	$ 427 [2]	$273	$ 1	$1,016
Intersegment revenues	39	(195) [2]	167	(11)	—
Restructuring costs and asset impairments	—	353	1	—	354
Operating income (loss)	135	(427)	31	(19)	(280)
EBIT	147	(353)	44	(7)	(169)

	Six Months Ended June 30, 2001				
	Pipelines	Merchant Energy	Field Services	Other[1]	Total
	(In millions)				
Revenues from external customers	$350	$ 739 [2]	$745	$ 1	$1,835
Intersegment revenues	39	(154) [2]	138	(23)	—
Merger-related costs and asset impairments	1	39	32	—	72
Operating income	176	283	23	9	491
EBIT	185	407	21	9	622

(1) Includes Corporate and eliminations.

(2) Merchant Energy revenues take into account the adoption of EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities on a net basis. See Note 1 regarding the adoption of this Issue.

The reconciliations of EBIT to income (loss) before extraordinary items and cumulative effect of accounting change and total assets are presented below:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Total EBIT	$74	$276	$(169)	$622
Non-affiliated interest and debt expense	32	37	71	78
Affiliated interest expense, net	25	44	43	109
Minority interest	6	—	12	—
Income taxes	3	75	(99)	147
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 8	$120	$(196)	$288

	June 30, 2002	December 31, 2001
Pipelines	$ 5,132	$ 5,047
Merchant Energy	12,009	11,994
Field Services	855	2,517
Other	476	437
Total segment assets	$18,472	$19,995

10. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for our proportionate share of unconsolidated affiliates below 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. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had a net loss of less than $1 million and $2 million for the quarter and six months ended June 30, 2002 and net income of less than $1 million for the quarter and six months ended June 30, 2001.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Operating results data				
Operating revenues	$286	$215	$465	$433
Operating expenses	197	139	301	266
Income from continuing operations	76	36	73	62
Net income	76	36	73	54

El Paso Energy Partners

In March 2001, we sold natural gas liquids transportation and fractionation assets acquired in our December 2000 acquisition of PG&E's Texas midstream operations to El Paso Energy Partners, for approximately $133 million.

In April 2002, we sold midstream assets for approximately $265 million to El Paso Energy Partners. Net proceeds from this sale were approximately $259 million in cash, and common units of El Paso Energy Partners with a fair value of $6 million. No gain or loss was recognized on this sale.

We are in the process of selling onshore and offshore natural gas and oil gathering systems, natural gas liquids transportation and fractionation assets to El Paso Energy Partners. See Note 2 for further discussion. This proposed sale has been approved by both our parent's and El Paso Energy Partners' Board of Directors which included the approval of El Paso Energy Partners' special conflicts committee. There were also fairness opinions on the transaction. This transaction is subject to customary regulatory review and approval. The closing of the sale is anticipated by the end of 2002.

Other

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowings from outside sources. We had net borrowings of $2,556 million at June 30, 2002, at a market rate of interest which was 1.9% and $2,364 million at December 31, 2001, at a market interest rate of 2.1%. In addition, we had demand note receivables with El Paso of $54 million at June 30, 2002, with interest rates that ranged from 2.4% to 2.5% and $40 million at December 31, 2001, with interest rates that ranged from 2.7% to 3.1%. We also had a note payable to El Paso of $56 million and $35 million at June 30, 2002 and December 31, 2001, at a current market rate.

At June 30, 2002 and December 31, 2001, we had current accounts and notes receivable from other related parties of $325 million and $231 million. In addition, we had current accounts payable to other related parties of $398 million and $533 million at June 30, 2002 and December 31, 2001. These balances arose in the normal course of business.

In January 2002, El Paso contributed gathering and processing assets to us with a net book value of $19 million. In March 2002, we distributed through a dividend to El Paso, a majority of our Texas midstream operations at their net book value of $330 million.

11. New Accounting Pronouncements Not Yet Adopted

Accounting for Asset Retirement Obligations

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement requires companies to record a liability for the estimated retirement and removal costs of assets used in their business. The liability is recorded at its present value, and the same amount is added to the recorded value of the asset and is amortized over the asset's remaining useful life. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this statement.

Reporting Gains and Losses from the Early Extinguishment of Debt

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* This statement addresses how to report gains or losses resulting from the early extinguishment of debt. Under current accounting rules, our non-rate regulated entities report any gains or losses on early extinguishment of debt as extraordinary items. When we adopt SFAS No. 145, we will be required to evaluate whether the debt extinguishment is truly extraordinary in nature. If we routinely extinguish debt early, the gain or loss will be included in income from continuing operations. This statement will be effective for our 2003 year-end reporting.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs that are associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The provisions of this statement are effective for fiscal years beginning after December 31, 2002 and will impact any exit or disposal activities initiated after January 1, 2003.

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our Annual Report on Form 10-K filed March 25, 2002, in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Below is a list of terms that are common to our industry and used throughout our Management's Discussion and Analysis:

Btu	=	British thermal unit	MBbls	=	thousand barrels
BBtu/d	=	billion British thermal units per day	MMBtu	=	million British thermal units
BBtue/d	=	billion British thermal unit equivalents per day	MMcf	=	million cubic feet
			MMWh	=	thousand megawatt hours

Recent Developments

In December 2001, El Paso announced a plan to strengthen its capital structure and enhance its liquidity. In May 2002, El Paso also announced a plan to limit its investment in, and exposure to energy trading and to focus its activities and investment in its core natural gas businesses. A key component of these plans impacts our Merchant operations in that working capital and credit limits will now be implemented on our trading business.

As a result of current circumstances surrounding the energy sector, the creditworthiness of several industry participants has been called into question. We have taken actions to mitigate our exposure to these participants; however, should several of these participants file for Chapter 11 bankruptcy protection and our contracts are not assumed by other counterparties, it could have a material adverse effect on our financial position, operating results or cash flows.

Results of Operations

Our results of operations, along with the impact by segment of the restructuring and merger-related costs, asset impairments and other charges, are presented below. Pro-forma amounts should not be used as a substitute for amounts reported under generally accepted accounting principles. They are presented solely to improve the understanding of the impact of the charges reported during the periods presented. The results are as follows (in millions):

	Quarter Ended June 30,					
	2002			2001		
	Reported	Charges[(1)]	Pro-forma	Reported	Charges[(1)]	Pro-forma
Pipelines	$ 66	$—	$ 66	$ 72	$ —	$ 72
Merchant Energy	(1)	11	10	176	39	215
Field Services	17	1	18	20	4	24
Segment EBIT	82	12	94	268	43	311
Corporate	(8)	—	(8)	8	—	8
Consolidated EBIT	74	12	86	276	43	319
Non-affiliated interest and debt expense	(32)	—	(32)	(37)	—	(37)
Affiliated interest and debt expense	(25)	—	(25)	(44)	—	(44)
Minority interest	(6)	—	(6)	—	—	—
Income taxes	(3)	(4)	(7)	(75)	(15)	(90)
Extraordinary items, net of taxes	—	—	—	38	(38)	—
Net income	$ 8	$ 8	$ 16	$158	$(10)	$148

(1) Charges include restructuring and merger-related costs, asset impairments and extraordinary items. See Item 1, Financial Statements, for further discussion of these charges.

	Six Months Ended June 30,					
	2002			2001		
	Reported	Charges[1]	Pro-forma	Reported	Charges[1]	Pro-forma
Pipelines	$ 147	$ —	$147	$ 185	$ 1	$ 186
Merchant Energy	(353)	353	—	407	39	446
Field Services	44	1	45	21	32	53
Segment EBIT	(162)	354	192	613	72	685
Corporate	(7)	—	(7)	9	—	9
Consolidated EBIT	(169)	354	185	622	72	694
Non-affiliated interest and debt expense	(71)	—	(71)	(78)	—	(78)
Affiliated interest and debt expense	(43)	—	(43)	(109)	—	(109)
Minority interest	(12)	—	(12)	—	—	—
Income taxes	99	(119)	(20)	(147)	(24)	(171)
Extraordinary items, net of taxes	—	—	—	38	(38)	—
Accounting changes, net of taxes	97	(97)	—	—	—	—
Net income (loss)	$ (99)	$ 138	$ 39	$ 326	$ 10	$ 336

(1) Charges include restructuring and merger-related costs, asset impairments, extraordinary items and a cumulative effect of accounting change. See Item 1, Financial Statements, for further discussions of these charges.

Segment Results

Our three segments: Pipelines, Merchant Energy and Field Services are strategic business units that offer a variety of different energy products and services; each requires different technology and marketing strategies. We evaluate our segment performance based on EBIT. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the trading portion of Merchant Energy and for the Field Services segment. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 9, as well as our Annual Report on Form 10-K for the year ended December 31, 2001. The segment EBIT results for the periods ended June 30 presented below include the charges discussed above:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Pipelines	$ 66	$ 72	$ 147	$185
Merchant Energy	(1)	176	(353)	407
Field Services	17	20	44	21
Segment total	82	268	(162)	613
Corporate	(8)	8	(7)	9
Consolidated EBIT	$ 74	$276	$(169)	$622

Pipelines

Pipeline results are relatively stable, but can be subject to variability from a number of factors, such as weather conditions, including those conditions that may impact the amount of power produced by natural gas fired turbines, as well as gas supply availability which can displace the pipeline's delivery capabilities to the markets they serve. Results can also be impacted by the ability to market excess natural gas which is influenced by a pipeline's rate of recovery for use and efficiencies of the compression equipment. Future revenues may also be impacted by expansion projects in our service areas, competition by other pipelines for those expansion needs and regulatory impacts on rates. Results of our Pipelines segment operations were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Operating revenues	$ 166	$ 170	$ 354	$ 389
Operating expenses	(107)	(105)	(219)	(213)
Other income	7	7	12	9
EBIT	$ 66	$ 72	$ 147	$ 185
Throughput volumes (BBtu/d)[(1)]	4,575	4,407	4,849	4,884

(1) Throughput volumes for 2001 exclude Midwestern Gas Transmission system sold in connection with the FTC order related to El Paso's merger with Coastal.

Second Quarter 2002 Compared to Second Quarter 2001

Operating revenues for the quarter ended June 30, 2002, were $4 million lower than the same period in 2001. The decrease was primarily due to the favorable resolution of regulatory issues related to natural gas purchase contracts in 2001 and the impact of lower natural gas prices on excess natural gas recoveries in 2002. Also contributing to the decrease was the sale of the Midwestern Gas Transmission system in April 2001. The decrease was partially offset by revenues from transmission system expansion projects placed in service in 2002 and a favorable resolution of measurement issues at a processing plant serving the TGP system.

Operating expenses for the quarter ended June 30, 2002, were $2 million higher than the same period in 2001. The increase was primarily due to higher amortization of additional acquisition cost assigned to utility plant, higher field operational costs, higher costs associated with gas storage and higher electric compression costs in 2002. The increase was partially offset by lower corporate overhead allocations in the second quarter of 2002 and reduced operating and depreciation expenses due to the sale of the Midwestern system in April 2001.

Six Months Ended 2002 Compared to Six Months Ended 2001

Operating revenues for the six months ended June 30, 2002, were $35 million lower than the same period in 2001. The decrease was primarily due to the favorable resolution of regulatory issues related to natural gas purchase contracts in 2001 and the impact of lower natural gas prices on excess natural gas recoveries in 2002. Also contributing to the decrease were lower transportation revenues from capacity sold under short-term contracts in 2002, as well as the sale of the Midwestern Gas Transmission system in April 2001 and lower revenues due to milder weather in 2002. Partially offsetting the decrease were revenues from transmission system expansion projects placed in service in 2002 and a favorable resolution of measurement issues at a processing plant serving the TGP system.

Operating expenses for the six months ended June 30, 2002, were $6 million higher than the same period in 2001. The increase was primarily due to higher amortization of additional acquisition cost assigned to utility plant, higher field operational costs, higher costs associated with gas storage and higher electric compression costs in 2002. Also contributing to the increase were lower project development costs in the first quarter of 2001. Partially offsetting the increase were lower corporate overhead allocations in the second quarter of 2002 and reduced operating and depreciation expenses due to the sale of the Midwestern system in April 2001.

Other income for the six months ended June 30, 2002, was $3 million higher than the same period in 2001 primarily due to higher equity earnings resulting from reduced losses on our investment in Australia in 2002.

New Expansion Project. The FERC approved TGP's Can-East project and related compressor facilities in June 2002. Service is anticipated to commence in November 2002. The Can-East project will extend TGP's mainline pipeline system to the Leidy Hub using 280 million cubic feet of capacity per day that TGP currently plans to lease from Dominion Resources and National Fuel Gas Supply Corp.

Merchant Energy

Our Merchant Energy segment conducts our customer origination, trading and power activities.

Energy-Related Price Risk Management Activities

As of June 30, 2002, the net fair value of our energy contracts was $1,052 million. Of this amount, the net fair value of our trading-related energy contracts was $1,051 million. Our trading activities generated margins during the six months ended June 30, 2002 and 2001 totaling $1 million and $381 million.

The following table details the net fair value of our energy contracts by year of maturity and valuation methodology as of June 30, 2002:

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Trading contracts						
Prices actively quoted	$(77)	$443	$247	$148	$ 4	$ 765
Prices based on models and other valuation methods	132	84	28	18	24	286
Total trading contracts, net	55	527	275	166	28	1,051
Non-trading contracts, net	—	1	—	—	—	1
Total energy contracts	$ 55	$528	$275	$166	$28	$1,052

A reconciliation of our trading and non-trading energy contracts for the six months ended June 30, 2002, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2001	$1,337	$ 23	$1,360
Fair value of contracts settled during the period	(378)	(13)	(391)
Initial recorded value of new contracts	71[(1)]	—	71
Change in fair value of contracts	60	(9)	51
Changes in fair value attributable to changes in valuation techniques	(69)	—	(69)
Other	30	—	30
Net change in contracts outstanding during the period	(286)	(22)	(308)
Fair value of contracts outstanding at June 30, 2002	$1,051	$ 1	$1,052

(1) Relates primarily to the completion of our Snøhvit LNG supply contract in the second quarter of 2002. See the discussion of this transaction under results of operations below.

Included in "Changes in fair value attributable to changes in valuation techniques" in our trading price risk management activities is a first quarter charge of approximately $61 million related to our revised estimate of the fair value of long-term trading positions. Specifically, we have experienced diminished liquidity in the marketplace for natural gas and power transactions in excess of ten years. Because we do not expect this condition to change in the foreseeable future, we do not recognize gains from the fair value of trading or non-trading positions beyond ten years unless there is clearly demonstrated liquidity in a specific market. Included in "Other" are option premiums and storage capacity transactions.

Results of Operations

Below are Merchant Energy's operating results and an analysis of these results for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Trading gross margin	$ (45)	$ 138	$ (14)	$ 328
Operating and other revenues	102	76	208	183
Operating expenses	(130)	(122)	(621)	(228)
Other income	72	84	74	124
EBIT	$ (1)	$ 176	$ (353)	$ 407
Volumes[(1)]				
Physical				
Natural gas (BBtue/d)	13,639	9,187	13,431	10,324
Power (MMWh)	108,683	45,386	214,564	81,584
Other energy commodities (MBbls)	6,478	4,032	12,781	5,324
Financial settlements (BBtue/d)	194,728	120,929	176,026	145,077

(1) Volumes include those settled in our origination and trading activities, as well as those generated at our power plants.

Trading gross margin consists of revenue from commodity trading and origination activities less the cost of commodities sold.

Second Quarter 2002 Compared to Second Quarter 2001

During the quarter ended June 30, 2002, we completed a significant transaction related to a long-term LNG supply contract. In May 2002, we received final approval from the Norwegian and United States governments on an LNG purchase and sale agreement signed in October 2001 with a consortium of natural gas production companies led by Statoil ASA. The consortium will develop the Snøhvit Project in northern Norway, and we will receive LNG shipments equivalent to an estimated 91 billion cubic feet per year of natural gas during the 17-year term of the agreement with the possibility of a 3-year extension. The first delivery is scheduled between October 2005 and October 2006. The Snøhvit agreement is a derivative under SFAS No. 133, which we were required to mark to its fair value when it was finalized. As a result, we recorded a $59 million gain in the second quarter of 2002 from this transaction.

For the quarter ended June 30, 2002, trading gross margin was $183 million lower than the same period in 2001. The decrease was due to lower trading margins primarily due to a weaker trading environment and lower price volatility in the natural gas and power markets in the second quarter of 2002, partially offset by the $59 million gain on the Snøhvit transaction.

Operating and other revenues consist of revenues from domestic and international power generation facilities and investments, including our management fee from Chaparral, and revenues from EnCap and our other financial services businesses. For the quarter ended June 30, 2002, operating and other revenues were $26 million higher than the same period in 2001. The increase resulted from higher management fee income, primarily from Chaparral, as well as higher income from our financial services businesses, during the second quarter of 2002.

Operating expenses for the quarter ended June 30, 2002, were $8 million higher than the same period in 2001. The increase was primarily a result of severance expensed in the second quarter of 2002 in conjunction with the restructuring of our trading business.

Other income for the quarter ended June 30, 2002, was $12 million lower than the same period in 2001. The decrease was primarily the result of marketing, agency and technical services fees related to the development of the Macae power project in Brazil which were recorded in the second quarter of 2001, partially offset by an increase in equity earnings from unconsolidated projects in the second quarter of 2002.

Six Months Ended 2002 Compared to Six Months Ended 2001

During the six months ended June 30, 2002, we completed a power contract restructuring transaction at our Mount Carmel plant. This transaction, which occurred in the first quarter of 2002, involved the termination of the existing power purchase contract for a fee from the utility of $50 million. In addition, we recorded a non-cash adjustment to reflect the estimated fair value of the Mount Carmel power plant of $25 million, resulting in a total net benefit on the restructuring transaction of $25 million.

For the six months ended June 30, 2002, trading gross margin was $342 million lower than the same period in 2001. The decrease was due to a weaker trading environment and lower price volatility in the natural gas and power markets in the second quarter of 2002. This decrease was partially offset by the Mount Carmel power contract restructuring described above and a $59 million gain from our Snøhvit transaction.

For the six months ended June 30, 2002, operating and other revenues were $25 million higher than the same period in 2001. The increase primarily resulted from higher management fees from Chaparral.

Operating expenses for the six months ended June 30, 2002, were $393 million higher than the same period in 2001. The increase resulted from a $342 million impairment of our power investments in Argentina in the first quarter of 2002, a $19 million turbine forfeiture fee for a cancelled power project during 2002, and an increase in corporate overhead allocation to Merchant Energy in 2002. Also contributing to this increase were higher operating expenses resulting from the expansion of our LNG business in 2002 and more extensive operations in Europe and Mexico in 2002 as compared to 2001. The increase was partially offset by a $38 million impairment of our investment in the East Asia Power project in the Philippines in the second quarter of 2001.

Other income for the six months ended June 30, 2002, was $50 million lower than the same period in 2001. The decrease was primarily the result of marketing, agency and technical services fees related to the development of the Macae power project in Brazil which were recorded in the second quarter of 2001.

Field Services

Our Field Services segment conducts our midstream activities. During 2002, we have entered into several transactions to divest most of our midstream assets. In the first six months of 2002:

- We contributed to our parent in March 2002 the gathering and processing assets we acquired in our acquisition of PG&E's midstream assets in December 2000, including the EPGT Texas intrastate pipeline system (our parent subsequently sold the EPGT Texas system to El Paso Energy Partners in April 2002). These assets generated EBIT of $26 million for the year ended December 31, 2001.
- We sold gathering and processing assets in April 2002 to El Paso Energy Partners, of which we have an approximate 7 percent ownership interest. These assets included the Waha gathering and treating system, the Carlsbad gathering system and an approximate 42.3 percent non-operating interest in the Indian Basin processing plant. These assets generated EBIT of $26 million during the year ended December 31, 2001.

Our parent also announced in July 2002 the proposed sale of substantially all our natural gas gathering, processing and treating assets in the San Juan Basin to El Paso Energy Partners. We expect this transaction to be completed by the end of 2002. The San Juan Basin assets generated EBIT of $104 million during the year ended December 31, 2001.

With the completion of these transactions, we will have divested of a substantial portion of our midstream business. As a result, we expect our future EBIT to decrease considerably due to a decline in our gathering, treating, and processing activities. However, we expect the increase in earnings from our interest in the partnership to offset, in part, the anticipated decrease in EBIT.

Results of our Field Services segment operations were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Total gross margins	$ 42	$ 100	$ 127	$ 209
Operating expenses	(31)	(75)	(96)	(186)
Other income (loss)	6	(5)	13	(2)
EBIT	$ 17	$ 20	$ 44	$ 21
Volume and prices				
Gathering and treating				
Volumes (BBtu/d)	1,487	4,962	2,848	5,066
Prices ($/MMBtu)	$ 0.24	$ 0.14	$ 0.18	$ 0.14
Processing				
Volumes (inlet BBtu/d)	812	2,408	1,356	2,178
Prices ($/MMBtu)	$ 0.12	$ 0.17	0.12	$ 0.18

Second Quarter 2002 Compared to Second Quarter 2001

Total gross margins for the quarter ended June 30, 2002, were $58 million lower than the same period in 2001. The decrease in gathering, treating and processing margins was primarily due to the disposition of assets in March and April 2002. Processing margins also declined due to lower natural gas liquids (NGL) prices in 2002 and higher costs associated with a new processing arrangement at the Chaco processing facility entered into in the fourth quarter of 2001 with El Paso Energy Partners. Excluding the results of the divested assets, gathering and treating margins were higher due to the unfavorable resolution of fuel disputes in the second quarter of 2001, partially offset by lower natural gas prices in the San Juan Basin in 2002.

Operating expenses for the quarter ended June 30, 2002, were $44 million lower than the same period of 2001. The decrease was primarily a result of lower operating and depreciation expenses attributable to our disposition of assets in 2002, and $4 million in merger-related costs arising from payments to El Paso Energy Partners related to FTC ordered sales of assets owned by the partnership in 2001 following the El Paso merger with Coastal.

Other income for the quarter ended June 30, 2002, was $11 million higher than the same period in 2001 principally due to higher earnings in 2002 from our interest in El Paso Energy Partners.

Six Months Ended 2002 Compared to Six Months Ended 2001

Total gross margins for the year ended June 30, 2002, were $82 million lower than the same period in 2001. The decrease in gathering, treating and processing margins was primarily due to the disposition of assets in March and April of 2002. Processing margins also decreased due to lower NGL prices in 2002 and higher costs associated with a new processing arrangement at the Chaco processing facility entered into in the fourth quarter of 2001 with El Paso Energy Partners. Excluding the results of the divested assets, gathering and treating margins were higher due to the favorable resolution of fuel, rate and volume matters in the first quarter of 2002, unfavorable resolution of fuel disputes in the second quarter of 2001, and higher realized transportation rates from the pipeline system acquired in our acquisition of PG&E's midstream assets. Partially offsetting these increases were lower natural gas prices in the San Juan Basin in 2002.

Operating expenses for the six months ended June 30, 2002, were $90 million lower than the same period of 2001. The decrease was primarily a result of lower operating and depreciation expenses due to our disposition of assets in 2002, merger-related costs of $32 million arising from payments to El Paso Energy Partners in 2001 related to FTC ordered sales of assets owned by the partnership and merger-related employee relocation expenses in 2001 following the El Paso merger with Coastal.

Other income for the six months ended June 30, 2002, was $15 million higher than the same period in 2001 principally due to higher earnings in 2002 from our interests in El Paso Energy Partners.

Interest and Debt Expense

Non-affiliated Interest and Debt Expense, Net

Non-affiliated interest and debt expense, net for the quarter and six months ended June 30, 2002, was $5 million and $7 million lower than the same period in 2001 primarily due to a reduction of long-term debt and lower interest rates on commercial paper borrowings. This decrease was partially offset by a decrease in capitalized interest due to lower rates on construction projects.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the quarter and six months ended June 30, 2002, was $19 million and $66 million lower than the same period in 2001 primarily due to lower short-term interest rates on average advances from El Paso under our cash management program with them.

Income Taxes

Income tax expense for the quarter ended June 30, 2002, was $3 million, resulting in an effective tax rate of 27 percent. Income tax benefit for the six months ended June 30, 2002, was $99 million, resulting in an effective tax rate of 34 percent. Our effective tax rates for both periods were different than the statutory rate of 35 percent primarily due to the following:

- state income taxes; and
- foreign income taxed at different rates.

Income tax expense for the quarter and six months ended June 30, 2001, was $75 million and $147 million, resulting in effective tax rates of 38 percent and 34 percent. Our effective tax rates were different than the statutory tax rate of 35 percent primarily due to the following:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income taxed at different rates.

Liquidity and Capital Resources

Cash From Operating Activities

Net cash used in our operating activities was $503 million for the six months ended June 30, 2002, compared to net cash provided by operating activities of $3,192 million for the same period in 2001. The decrease was primarily due to cash paid for broker and over-the-counter margins in 2002, as well as less cash generated through liquidations of price risk management assets. Also contributing to the decrease is the change in Merchant Energy payables related to the purchase of natural gas, as well as higher 2001 electricity rates and volumes, compared to 2002.

Cash From Investing Activities

Net cash provided by our investing activities was $124 million for the six months ended June 30, 2002. Our investing activities primarily consisted of net proceeds from the sale of midstream assets to El Paso

Energy Partners. Cash outflows consisted mainly of additions to our property, plant and equipment primarily in our Pipelines and Merchant Energy segments for expansion and construction projects.

Cash From Financing Activities

Net cash provided by our financing activities was $307 million for the six months ended June 30, 2002. Cash provided from our financing activities included the issuance of long-term debt and cash advances received from El Paso under our cash management program. Cash outflows consisted primarily of dividends paid to our preferred and common shareholders.

During the six months ended June 30, 2002, we paid dividends of $12 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter). We also distributed $59 million of common dividends to our parent.

We expect that future funding for our working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt retirements, payments of dividends and other financing expenditures will be provided by internally generated funds, commercial paper issuances, available capacity under existing credit facilities, the issuance of new long-term debt or equity, and/or contributions from El Paso.

During the first quarter of 2002, we distributed several of our midstream business entities which had $180 million of long-term debt to our parent, El Paso.

Credit Facilities and Available Capacity

In May 2002, El Paso renewed its $3 billion, 364-day revolving credit and competitive advance facility. TGP remains a designated borrower under this facility and, as such, is liable for any amounts outstanding under this facility. This facility matures in May 2003. In June 2002, El Paso amended its existing $1 billion, 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003, and TGP is a designated borrower under this facility and, as such, is liable for any amounts outstanding under this facility. The interest rate under both of these facilities varies based on El Paso's senior unsecured debt rating, and as of June 30, 2002, an initial draw would have had a rate of LIBOR plus 0.625%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts. As of June 30, 2002, there were no borrowings outstanding, and $450 million in letters of credit were issued under the $1 billion facility.

In June 2002, TGP issued $240 million aggregate principal amount 8.375% notes due 2032. Proceeds of approximately $238 million, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. As a result, TGP has no remaining capacity under its shelf registration statement on file with the SEC.

Other Commercial Commitments

In 2001, we entered into agreements to time-charter four separate ships to secure transportation for our developing liquefied natural gas business. In May 2002, we entered into amendments to three of the initial four time charters to reconfigure the ships with onboard regasification technology and to secure an option for an additional time charter for a fifth ship. The exercise of the option for the fifth ship will represent a commitment of $522 million over the term of such charter. However, we are obligated to pay a termination fee of $24 million in the event the option is not exercised by April 2003. The agreements provide for deliveries of vessels between 2003 and 2005. Each time charter has a twenty-year term commencing when the vessels are delivered with the possibility of two five-year extensions. The total commitment under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. We are party to an agreement with an unaffiliated global integrated oil and gas company under which the third party agrees to bear 50 percent of the risk incidental to the initial $1.8 billion commitment made for the first four time charters.

Commitments and Contingencies

See Item 1, Financial Statements, Note 8, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 11, which is incorporated herein by reference.

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Annual Report on Form 10-K for the year ended December 31, 2001, except as presented below:

Commodity Price Risk

The following table presents our potential one-day unfavorable impact on earnings before interest and income taxes as measured by Value-at-Risk using the historical simulation technique for our energy related contracts and is prepared based on a confidence level of 95 percent and a one-day holding period:

	June 30, 2002	December 31, 2001
	(In millions)	
Trading Value-at-Risk	$12	$18
Non-Trading Value-at-Risk	$ 3	$ 7
Portfolio Value-at-Risk	$ 9	$14

Portfolio Value-at-Risk represents the combined Value-at-Risk for the trading and non-trading price risk management activities. The separate calculation of Value-at-Risk for trading and non-trading contracts ignores the natural correlation that exists between commodity contracts and prices. As a result, the individually determined values will be higher than the combined Value-at-Risk in most instances. We manage our risks through a portfolio approach that balances both trading and non-trading risks.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8, which is incorporated herein by reference.

The *California* cases are: five filed in the Superior Court of Los Angeles County (*Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000; and *Berg v. Southern California Gas Company, et al;* filed December 18, 2000; *County of Los Angeles v. Southern California Gas Company, et al,* filed January 8, 2002; *The City of Los Angeles, et al v. Southern California Gas Company, et al;* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001); two filed in the Superior Court of San Diego County (*John W.H.K. Phillip v. El Paso Merchant Energy;* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000); three filed in the Superior Court of San Francisco County (*Sweetie's, et al v. El Paso Corporation, et al,* filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al,* filed May 9, 2001; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda (*Dry Creek Corporation v. El Paso Natural Gas Company, et al,* filed December 10, 2001).

Item 2. Changes in Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

We held our annual meeting of stockholders on May 20, 2002. Proposals we presented for a stockholders' vote included the election of one director by holders of EPTPC's 8¼% Cumulative Preferred Stock, Series A, and the election of five Directors by El Paso, the sole holder of EPTPC's Common Stock.

The one director nominated to be elected by the holder of EPTPC's 8¼% Cumulative Preferred Stock Series A was elected with the following voting results:

	For	Abstain
Kenneth L. Smalley	3,555,432	150

Each of the five directors nominated to be elected by the common stockholder were elected with the following voting results:

	For	Abstain
William A. Wise	1,971	0
H. Brent Austin	1,971	0
Peggy A. Heeg	1,971	0
Joel Richards III	1,971	0
Jeffrey I Beason	1,971	0

There were no broker non-votes for the election of directors.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

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

Exhibit Number	Description
*10.A	— $3,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement dated May 15, 2002, by and among El Paso, EPNG, TGP, the several banks and other institutions from time to time parties thereto and JPMorgan Chase Bank, as Administrative Agent and CAF Advance Agent, ABN Amro Bank N.V. and Citibank, N.A., as Co-Documentation Agents, and Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents.
*10.B	— Amended and Restated $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated June 27, 2002, by and among El Paso, EPNG, TGP, El Paso CGP, the several banks and other institutions from time to time parties thereto and JPMorgan Chase Bank, as Administrative Agent, CAF Advance Agent and Issuing Bank, Citibank, N.A. and ABN Amro Bank N.V. as Co-Documentation Agents, and Bank of America, N.A., as Syndication Agent.
*99.A	— Certification of Chief Executive Officer pursuant to 18 U.S.C.§ 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.
*99.B	— Certification of Chief Financial Officer pursuant to 18 U.S.C.§ 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

b. Reports on Form 8-K

None.

SIGNATURES

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

EL PASO TENNESSEE PIPELINE CO.

Date: August 14, 2002

/s/ H. BRENT AUSTIN

H. Brent Austin
Executive Vice President,
Chief Financial Officer and
Director (Principal Financial Officer)

Date: August 14, 2002

/s/ JEFFREY I. BEASON

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