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

FORM 10-Q

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

For the quarterly period ended March 31, 2006

OR

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

Commission File No. 1-10403

TEPPCO Partners, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**76-0291058**
(State of Incorporation or Organization)	(I.R.S. Employer Identification Number)

2929 Allen Parkway
P.O. Box 2521
Houston, Texas 77252-2521
(Address of principal executive offices, including zip code)

(713) 759-3636
(Registrant's telephone number, including area code)

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 o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one): Large accelerated filer ☒ Accelerated Filer o Non-accelerated Filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. Limited Partner Units outstanding as of May 2, 2006: 69,963,554

TEPPCO PARTNERS, L.P.

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Item 1. Financial Statements

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Unaudited)
(in thousands)

	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89	$ 119
Accounts receivable, trade (net of allowance for doubtful accounts of $100 and $250)	975,293	803,373
Accounts receivable, related parties	2,810	5,207
Inventories	46,584	29,069
Other	50,174	61,361
Total current assets	1,074,950	899,129
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $492,818 and $474,332)	1,936,755	1,960,068
Equity investments	347,376	359,656
Intangible assets	368,630	376,908
Goodwill	16,944	16,944
Other assets	69,927	67,833
Total assets	$ 3,814,582	$ 3,680,538
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 974,988	$ 800,033
Accounts payable, related parties	6,197	11,836
Accrued interest	14,967	32,840
Other accrued taxes	13,193	16,532
Other	36,247	75,970
Total current liabilities	1,045,592	937,211
Senior Notes	1,112,054	1,119,121
Other long-term debt	435,000	405,900
Other liabilities and deferred credits	22,677	16,936
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	1,918	11
General partner's interest	(62,669)	(61,487)
Limited partners' interests	1,260,010	1,262,846
Total partners' capital	1,199,259	1,201,370
Total liabilities and partners' capital	$ 3,814,582	$ 3,680,538

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)
(in thousands, except per Unit amounts)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)
Operating revenues:		
Sales of petroleum products	$ 2,396,346	$ 1,385,067
Transportation – Refined products	31,799	34,965
Transportation – LPGs	29,421	32,231
Transportation – Crude oil	8,923	9,172
Transportation – NGLs	10,653	10,219
Gathering – Natural gas	41,375	36,560
Other	17,852	15,577
Total operating revenues	2,536,369	1,523,791
Costs and expenses:		
Purchases of petroleum products	2,371,165	1,371,090
Operating, general and administrative	55,579	49,880
Operating fuel and power	14,297	11,070
Depreciation and amortization	28,757	25,611
Taxes – other than income taxes	5,311	5,406
Gains on sales of assets	(1,378)	(498)
Total costs and expenses	2,473,731	1,462,559
Operating income	62,638	61,232
Interest expense – net	(21,143)	(19,287)
Equity earnings	989	4,094
Other income – net	899	266
Income from continuing operations	43,383	46,305
Income from discontinued operations	1,607	1,124
Gain on sale of discontinued operations	17,884	—
Discontinued operations	19,491	1,124
Net income	$ 62,874	$ 47,429
Net Income Allocation:		
Limited Partner Unitholders income from continuing operations	$ 30,628	$ 32,947
Limited Partner Unitholders income from discontinued operations	13,760	800
Total Limited Partner Unitholders net income allocation	44,388	33,747
General Partner income from continuing operations	12,755	13,358
General Partner income from discontinued operations	5,731	324
Total General Partner net income allocation	18,486	13,682
Total net income allocated	$ 62,874	$ 47,429
Basic and diluted net income per Limited Partner Unit:		
Continuing operations	$ 0.43	$ 0.53
Discontinued operations	0.20	0.01
Basic and diluted net income per Limited Partner Unit	$ 0.63	$ 0.54
Weighted average Limited Partner Units outstanding	69,964	62,999

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)

Cash flows from operating activities:		
Net income from continuing operations	$ 43,383	$ 46,305
Adjustments to reconcile net income to cash provided by operating activities from continuing operations:		
Depreciation and amortization	28,757	25,611
Earnings in equity investments	(989)	(4,094)
Distributions from equity investments	16,297	4,719
Gains on sales of assets	(1,378)	(498)
Non-cash portion of interest expense	443	405
(Increase) decrease in accounts receivable	(171,920)	34,354
Decrease in accounts receivable, related parties	2,397	9,849
Increase in inventories	(17,488)	(1,791)
(Increase) decrease in other current assets	11,187	(605)
Increase (decrease) in accounts payable and accrued expenses	134,962	(77,556)
Decrease in accounts payable, related parties	(5,639)	(20,519)
Other	(2,919)	(1,654)
Net cash provided by operating activities from continuing operations	37,093	14,526
Cash flows from discontinued operations	1,631	1,277
Net cash provided by operating activities	38,724	15,803
Cash flows from investing activities:		
Proceeds from sales of assets	39,030	510
Investment in Mont Belvieu Storage Partners, L.P.	(1,720)	—
Purchase of assets	—	(7,101)
Capital expenditures	(38,272)	(27,589)
Net cash used in investing activities	(962)	(34,180)
Cash flows from financing activities:		
Proceeds from revolving credit facilities	187,700	138,700
Repayments on revolving credit facilities	(158,600)	(59,700)
Distributions paid	(66,892)	(58,658)
Net cash provided by (used in) financing activities	(37,792)	20,342
Net increase (decrease) in cash and cash equivalents	(30)	1,965
Cash and cash equivalents at beginning of period	119	16,422
Cash and cash equivalents at end of period	$ 89	$ 18,387
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ 38,450	$ 36,759

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(Unaudited)
(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Income	Total
Partners' capital at December 31, 2005	69,963,554	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370
Net income allocation	—	18,486	44,388	—	62,874
Cash distributions	—	(19,668)	(47,224)	—	(66,892)
Changes in fair values of crude oil cash flow hedges	—	—	—	236	236
Changes in fair values of interest rate cash flow hedges	—	—	—	1,671	1,671
Partners' capital at March 31, 2006	69,963,554	$ (62,669)	$ 1,260,010	$ 1,918	$ 1,199,259

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(in thousands)

		Three Months Ended March 31,		
		2006		2005 (as restated)
Net income	$	62,874	$	47,429
Changes in fair values of crude oil cash flow hedges		236		—
Changes in fair values of interest rate cash flow hedges		1,671		—
Comprehensive income	$	64,781	$	47,429

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1. ORGANIZATION AND BASIS OF PRESENTATION

TEPPCO Partners, L.P. (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990. We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us.

As used in this Report, "we," "us," "our," the "Partnership" and "TEPPCO" mean TEPPCO Partners, L.P. and, where the context requires, include our subsidiaries.

Through February 23, 2005, the General Partner was an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and ConocoPhillips. Duke Energy held an interest of approximately 70% in DEFS, and ConocoPhillips held the remaining interest of approximately 30%. On February 24, 2005, the General Partner was acquired by DFI GP Holdings L.P. (formerly Enterprise GP Holdings L.P.) ("DFI"), an affiliate of EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan, for approximately $1.1 billion. As a result of the transaction, DFI owns and controls the 2% general partner interest in us and has the right to receive the incentive distribution rights associated with the general partner interest. In conjunction with an amended and restated administrative services agreement, EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us. As a result of the sale of our General Partner, DEFS and Duke Energy continued to provide some administrative services for us for a period of up to one year after the sale, at which time, we or EPCO assumed these services. Prior to the sale of our General Partner, DEFS also managed and operated certain of our TEPPCO Midstream assets for us under contractual agreements. We assumed the operations of these assets from DEFS, and certain DEFS employees became employees of EPCO effective June 1, 2005.

In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs were converted to Limited Partner Units, but they have not been listed for trading on the New York Stock Exchange. These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Limited Partner Units for $104.0 million. As of March 31, 2006, none of these Limited Partner Units had been sold by DFI.

The accompanying unaudited consolidated financial statements reflect all adjustments that are, in the opinion of our management, of a normal and recurring nature and necessary for a fair statement of our financial position as of March 31, 2006, and the results of our operations and cash flows for the periods presented. The results of operations for the three months ended March 31, 2006, are not necessarily indicative of results of our operations for the full year 2006. You should read these interim financial statements in conjunction with our consolidated financial statements and notes thereto presented in the TEPPCO Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2005. We have reclassified certain amounts from prior periods to conform to the current presentation.

We restated our consolidated financial statements and related financial information for the three months ended March 31, 2005, for an accounting correction. See Note 16 for a discussion of the restatement adjustment and the impact on previously issued financial statements.

Business Segments

We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies.

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products."

Net Income Per Unit

Basic net income per Limited Partner Unit ("Unit" or "Units") is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 70.0 million Units and 63.0 million Units for the three months ended March 31, 2006 and 2005, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each period (see Note 9). The General Partner was allocated $18.5 million (representing 29.4%) of net income for the three months ended March 31, 2006 and $13.7 million (representing 28.85%) of our net income for the three months ended March 31, 2005. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with the Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P. ("Partnership Agreement").

Diluted net income per Unit equaled basic net income per Unit for each of the three months ended March 31, 2006 and 2005, as there were no dilutive instruments outstanding.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 123(R) (revised 2004), *Share-Based Payment*. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. In April 2005, both the FASB and the Securities and Exchange Commission decided to delay the effective date for public companies to implement SFAS 123(R). SFAS 123(R) is now effective for public companies for annual periods beginning after June 15, 2005. Accordingly, we adopted SFAS 123(R) in the first quarter of 2006. We adopted SFAS 123(R) under the modified prospective transition method. Our 2000 Long Term Incentive Plan and our 2005 Phantom Unit Plan are liability awards under the provisions of this statement. No additional compensation expense has been recorded in connection with the adoption of SFAS 123(R) as we have historically recorded the associated liabilities at fair value. The adoption of SFAS 123(R) did not have a material effect on our financial position, results of operations or cash flows.

In June 2005, the Emerging Issues Task Force ("EITF") reached consensus in EITF 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, to provide guidance on how general partners in a limited partnership should determine whether they control a limited partnership and therefore should consolidate it. The EITF agreed that the presumption of general partner control would be overcome only when the limited partners have

either of two types of rights. The first type, referred to as "kick-out rights," is the right to dissolve or liquidate the partnership or otherwise remove the general partner without cause. The second type, referred to as "participating rights," is the right to effectively participate in significant decisions made in the ordinary course of the partnership's business. The kick-out rights and the participating rights must be substantive in order to overcome the presumption of general partner control. The consensus is effective for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified subsequent to the date of FASB ratification (June 29, 2005). For existing limited partnerships that have not been modified, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. Although this EITF did not directly impact us, it did impact our General Partner. Our General Partner adopted this EITF on January 1, 2006. The adoption of EITF 04-5 resulted in the consolidation of our results of operations and balance sheet into its consolidated financial statements.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS 154 establishes new standards on accounting for changes in accounting principles. All such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. SFAS 154 completely replaces APB Opinion No. 20, *Accounting Changes,* and SFAS No. 3, *Reporting Accounting Changes in Interim Periods*. However, it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. SFAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after June 1, 2005. The application of SFAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of SFAS 154. The adoption of SFAS 154 did not have a material effect on our financial position, results of operations or cash flows.

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We are currently evaluating what impact EITF 04-13 will have on our financial statements, but at this time, we do not believe that the adoption of EITF 04-13 will have a material effect on our financial position, results of operations or cash flows.

NOTE 2. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets,* which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill, but instead requires testing for impairment at least annually. We test goodwill for impairment annually at December 31.

To perform an impairment test of goodwill, we have identified our reporting units and have determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142.

The following table presents the carrying amount of goodwill at both March 31, 2006 and December 31, 2005, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944

Other Intangible Assets

The following table reflects the components of intangible assets, including excess investments, being amortized at March 31, 2006, and December 31, 2005 (in thousands):

	March 31, 2006		December 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements	$ 464,337	$ (126,293)	$ 464,337	$ (118,921)
Fractionation agreement	38,000	(15,200)	38,000	(14,725)
Other	9,898	(2,112)	10,226	(2,009)
Subtotal	512,235	(143,605)	512,563	(135,655)
Excess investments:				
Centennial Pipeline LLC	33,390	(13,681)	33,390	(12,947)
Seaway Crude Pipeline Company	27,100	(3,937)	27,100	(3,764)
Subtotal	60,490	(17,618)	60,490	(16,711)
Total intangible assets	$ 572,725	$ (161,223)	$ 573,053	$ (152,366)

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $8.0 million and $7.1 million for the three months ended March 31, 2006 and 2005, respectively. Amortization expense on excess investments included in equity earnings was $0.9 million and $1.2 million for the three months ended March 31, 2006 and 2005, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah Gas Gathering System ("Jonah") and the Val Verde Gas Gathering System ("Val Verde") are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. Revisions to these estimates may occur as additional production information is made available to us.

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis. Our fractionation agreement is being amortized over its contract period of 20 years. The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3

years to 15 years. The value of $8.7 million assigned to our crude supply and transportation intangible customer contracts is being amortized on a unit-of-production basis.

The value assigned to our excess investment in Centennial Pipeline LLC was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway Crude Pipeline Company was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment on a straight-line basis over a 39-year life related primarily to the life of the pipeline.

The following table sets forth the estimated amortization expense of intangible assets and the estimated amortization expense allocated to equity earnings for the years ending December 31 (in thousands):

	Intangible Assets	Excess Investments
2006	$ 32,477	$ 4,691
2007	33,379	5,113
2008	32,950	5,438
2009	30,703	6,878
2010	27,322	7,042

NOTE 3. INTEREST RATE SWAPS

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and receives a fixed rate of interest of 7.51%. During the three months ended March 31, 2006 and 2005, we recognized reductions in interest expense of $0.7 million and $1.8 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarters ended March 31, 2006 and 2005, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a loss of approximately $7.0 million and $0.9 million at March 31, 2006, and December 31, 2005, respectively.

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. These swap agreements were later terminated in 2002 resulting in gains of $44.9 million. The gains realized from the swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At March 31, 2006, the unamortized balance of the deferred gains was $31.3 million. In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment.

In January 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. These interest rate swaps mature in January 2008. We designated these swap agreements as cash flow hedges. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. Because these swaps are designated as cash flow hedges, the changes in fair value, to the extent the swaps are effective, are recognized in other comprehensive income until the hedged interest costs are recognized in earnings. During the three months ended March 31, 2006, we recognized increases in interest expense of $0.1 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. During the three months ended March 31, 2006, we measured the hedge effectiveness of these interest rate swaps and noted that no gain or loss from ineffectiveness was required to be recognized. The total fair value of the interest rate swap agreements was a gain of approximately $1.7 million at March 31, 2006.

NOTE 4. ACQUISITIONS

Mexia Pipeline

On March 31, 2005, we purchased crude oil pipeline assets for $7.1 million from BP Pipelines (North America) Inc. ("BP"). The assets include approximately 158 miles of pipeline, which extend from Mexia, Texas, to the Houston, Texas, area and two stations in south Houston with connections to a BP pipeline that originates in south Houston. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment. We have integrated these assets into our South Texas pipeline system, which is included in our Upstream Segment.

NOTE 5. DISPOSITIONS AND DISCONTINUED OPERATIONS

Pioneer Plant

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming to an affiliate of Enterprise Products Partners L.P. ("Enterprise") for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party. The sales proceeds will be used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction are estimated to be approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months ended March 31, 2006 and 2005, are presented below (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Sales of petroleum products	$ 3,810	$ 2,142
Other	921	672
Total operating revenues	4,731	2,814
Purchases of petroleum products	2,861	1,370
Operating, general and administrative	182	138
Depreciation and amortization	51	152
Taxes – other than income taxes	30	30
Total costs and expenses	3,124	1,690
Net income from discontinued operations	$ 1,607	$ 1,124

Assets of the discontinued operations consisted of the following at December 31, 2005 (in thousands):

		December 31, 2005
Inventories	$	7
Property and equipment, net		19,812
Assets of discontinued operations	$	19,819

Cash flows from discontinued operations for the three months ended March 31, 2006 and 2005, are presented below (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Cash flows from operating activities:		
Net income	$ 19,491	$ 1,124
Depreciation and amortization	51	152
Gain on sale of Pioneer plant	(17,884)	—
(Increase) decrease in inventories	(27)	1
Total cash flows from discontinued operations	$ 1,631	$ 1,277

NOTE 6. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at March 31, 2006, and December 31, 2005. The major components of inventories were as follows (in thousands):

	March 31, 2006	December 31, 2005
Crude oil (1)	$ 18,359	$ 3,021
Refined products	3,801	4,461
LPGs	9,103	7,403
Lubrication oils and specialty chemicals	6,361	5,740
Materials and supplies	8,361	8,203
Other	599	241
Total	$ 46,584	$ 29,069

(1) At March 31, 2006, substantially all of our crude oil inventory was subject to forward sales contracts.

NOTE 7. EQUITY INVESTMENTS

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway Crude Pipeline Company (“Seaway”). The remaining 50% interest is owned by ConocoPhillips. We operate the Seaway assets. Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. For 2006, we are allocated 60% of revenue and expense for the period January 1, 2006, through May 12, 2006, and 40% for the period May 13, 2006, through December 31, 2006. Our share of revenue and expense of Seaway is 47% for 2006. Thereafter, we will receive 40% of revenue and expense of Seaway. During the three months ended March 31, 2006 and 2005, we received distributions from Seaway of $8.5 million and $4.7 million, respectively. During the three months ended March 31, 2006 and 2005, we did not invest any additional funds in Seaway.

TE Products owns a 50% ownership interest in Centennial Pipeline LLC (“Centennial”), and Marathon Petroleum Company LLC (“Marathon”) owns the remaining 50% interest. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. During the three months ended March 31, 2006 and 2005, TE Products did not invest any additional funds in Centennial. TE Products has not received any distributions from Centennial since its formation.

TE Products owns a 50% ownership interest in Mont Belvieu Storage Partners, L.P. (“MB Storage”), and Louis Dreyfus Energy Services L.P. (“Louis Dreyfus”) owns the remaining 50% interest. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage.

For the years ended December 31, 2006 and 2005, TE Products receives the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage’s income before depreciation expense, as defined in the Agreement of Limited Partnership of MB Storage. TE Products’ share of MB Storage’s earnings may be adjusted annually by the partners of MB Storage. Any amount of MB Storage’s annual income before depreciation expense in excess of $6.78 million is allocated evenly

between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the three months ended March 31, 2006 and 2005, TE Products' sharing ratio in the earnings of MB Storage was approximately 57.9% and 58.1%, respectively. During the three months ended March 31, 2006, TE Products received distributions from MB Storage of $7.8 million and contributed $1.7 million to MB Storage. During the three months ended March 31, 2005, TE Products received no distributions from MB Storage and made no contributions to MB Storage.

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage. Summarized combined financial information for Seaway, Centennial and MB Storage for the three months ended March 31, 2006 and 2005, is presented below (in thousands):

	Three Months Ended March 31,	
	2006	2005
Revenues	$ 38,635	$ 38,529
Net income	7,041	11,257

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of March 31, 2006, and December 31, 2005, is presented below (in thousands):

	March 31, 2006	December 31, 2005
Current assets	$ 37,564	$ 60,082
Noncurrent assets	626,964	630,212
Current liabilities	23,866	32,242
Long-term debt	150,000	150,000
Noncurrent liabilities	14,235	13,626
Partners' capital	476,427	494,426

NOTE 8. DEBT

Senior Notes

On January 27, 1998, TE Products completed the issuance of $180.0 million principal amount of 6.45% Senior Notes due 2008, and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and are being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 may not be redeemed prior to their maturity on January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, may be redeemed at any time after January 15, 2008, at the option of TE Products, in whole or in part, at the following redemption prices (expressed in percentages of the principal amount) during the twelve months beginning January 15 of the years indicated:

Year	Redemption Price
2008	103.755%
2009	103.380%
2010	103.004%
2011	102.629%
2012	102.253%
2013	101.878%
2014	101.502%
2015	101.127%
2016	100.751%
2017	100.376%

and thereafter at 100% of the principal amount, together in each case with accrued interest at the redemption date.

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank pari passu with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of March 31, 2006, TE Products was in compliance with the covenants of the TE Products Senior Notes.

On February 20, 2002, we completed the issuance of $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of March 31, 2006, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of March 31, 2006, we were in compliance with the covenants of these Senior Notes.

The following table summarizes the estimated fair values of the Senior Notes as of March 31, 2006, and December 31, 2005 (in millions):

	Face Value	Fair Value March 31, 2006	Fair Value December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 182.6	$ 183.7
7.625% Senior Notes, due February 2012	500.0	537.9	552.0
6.125% Senior Notes, due February 2013	200.0	200.0	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	223.4	224.1

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 3).

Revolving Credit Facility

On June 27, 2003, we entered into a $550.0 million unsecured revolving credit facility with a three year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00

(subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 9), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. On October 21, 2004, we amended and restated our Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On February 23, 2005, we amended our Revolving Credit Facility to remove the requirement that DEFS must at all times own, directly or indirectly, 100% of our General Partner, to allow for its acquisition by DFI (see Note 1). During the second quarter of 2005, we used a portion of the proceeds from an equity offering in May 2005 to repay a portion of the Revolving Credit Facility. On December 13, 2005, we again amended our Revolving Credit Facility as follows:

- Total bank commitments increased from $600.0 million to $700.0 million. The amendment also provided that the commitments under the credit facility may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions.
- The facility fee and the borrowing rate then in effect were reduced by 0.275%.
- The maturity date of the credit facility was extended from October 21, 2009, to December 13, 2010. Also under the terms of the amendment, we may request up to two, one-year extensions of the maturity date. These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions.
- The amendment also removed the $100.0 million limit on the total amount of standby letters of credit that can be outstanding under the credit facility.

At March 31, 2006, $435.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 5.3%. At March 31, 2006, we were in compliance with the covenants of this credit facility.

The following table summarizes the principal amounts outstanding under all of our debt instruments as of March 31, 2006, and December 31, 2005 (in thousands):

	March 31, 2006	December 31, 2005
Revolving Credit Facility, due December 2010	$ 435,000	$ 405,900
6.45% TE Products Senior Notes, due January 2008	179,945	179,937
7.625% Senior Notes, due February 2012	498,714	498,659
6.125% Senior Notes, due February 2013	199,023	198,988
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,522,682	1,493,484
Adjustment to carrying value associated with hedges of fair value	24,372	31,537
Total Debt Instruments	$ 1,547,054	$ 1,525,021

Letter of Credit

At March 31, 2006, we had outstanding an $11.9 million standby letter of credit in connection with crude oil purchased in the first quarter of 2006. This amount is expected to be paid during the second quarter of 2006.

NOTE 9. PARTNERS' CAPITAL AND DISTRIBUTIONS

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our available cash, generally defined in our Partnership Agreement as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion ("Available Cash"). Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target - $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target - $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target - Cash distributions greater than $0.45 per Unit	50%	50%

The following table reflects the allocation of total distributions paid during the three months ended March 31, 2006 and 2005 (in thousands, except per Unit amounts):

	Three Months Ended March 31,	
	2006	2005
Limited Partner Units	$ 47,224	$ 41,736
General Partner Ownership Interest	964	852
General Partner Incentive	18,704	16,070
Total Cash Distributions Paid	$ 66,892	$ 58,658
Total Cash Distributions Paid Per Unit	$ 0.675	$ 0.6625

On May 5, 2006, we will pay a cash distribution of $0.675 per Unit for the quarter ended March 31, 2006. The first quarter 2006 cash distribution will total $66.9 million.

General Partner's Interest

As of March 31, 2006, and December 31, 2005, we had deficit balances of $62.7 million and $61.5 million, respectively, in our General Partner's equity account. These negative balances do not represent assets to us and do not represent obligations of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statement of Partners' Capital for a detail of the General Partner's equity account). For the three months ended March 31, 2006, the General Partner was allocated $18.5 million (representing 29.4%) of our net income and received $19.7 million in cash distributions.

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our limited partners. The Capital Account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity accounts reflected under accounting principles generally accepted in the United States in our financial statements. Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1.999999% of the total Capital Accounts of all partners. At March 31, 2006, and December 31, 2005, the General Partner's Capital Account balance substantially exceeded this requirement.

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined in our Partnership Agreement as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Cash distributions in excess of net income allocations and capital contributions during the year ended December 31, 2005, and the three months ended March 31, 2006, resulted in deficits in the General Partner's equity account at December 31, 2005, and March 31, 2006. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership. If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit.

NOTE 10. RELATED PARTY TRANSACTIONS

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

We do not have any employees. We are managed by the Company, which prior to February 23, 2005, was an indirect wholly owned subsidiary of DEFS. According to our Partnership Agreement, the Company was entitled to reimbursement of all direct and indirect expenses related to our business activities. As a result of the change in ownership of the General Partner on February 24, 2005, all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to an administrative services agreement. We reimburse EPCO for the allocated costs of its employees who perform operating, management and other administrative functions for us (see Note 1).

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the three months ended March 31, 2006 and 2005 (in millions):

	Three Months Ended March 31,	
	2006	2005
Revenues from EPCO and affiliates: (1)		
Transportation – NGLs	$ 1.7	$ 0.9
Transportation – LPGs	1.7	0.8
Costs and Expenses from EPCO and affiliates: (1)		
Payroll and administrative (2)	29.2	—
Purchases of petroleum products (3)	5.7	—
Revenues from DEFS and affiliates: (4)		
Sales of petroleum products (5)	—	4.3
Transportation – NGLs	—	2.8
Gathering – Natural gas – Jonah	—	0.5
Transportation – LPGs	—	0.7
Other operating revenues	—	2.4
Costs and Expenses from DEFS and affiliates: (4)		
Payroll and administrative (2) (6)	—	16.2
Purchases of petroleum products	—	38.5

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions beginning February 24, 2005, at which time a change in ownership of the General Partner.occurred

(2) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(3) Includes purchases of condensate and expenses related to Lubrication Services, Inc.'s ("LSI") use of an affiliate of EPCO as a transporter.

(4) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions prior to February 23, 2005, at which time a change in ownership of the General Partner occurred.

(5) Includes LSI sales of lubrication oils and specialty chemicals and Jonah NGL sales in connection with Jonah's Pioneer processing plant operations, which began operating in 2004. Amounts associated with the Pioneer plant are reflected as discontinued operations in the accompanying financial statements.

(6) Includes operating costs and expenses related to DEFS managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under a contractual agreement established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we have assumed these activities.

At March 31, 2006 and December 31, 2005, we had a receivable from EPCO and affiliates of $2.3 million and $4.3 million, respectively, related to sales and transportation services provided to EPCO and affiliates. At March 31, 2006 and December 31, 2005, we had a payable to EPCO and affiliates of $5.2 million and $9.8 million, respectively, related to direct payroll, payroll related costs and other operational related costs.

Beginning February 24, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO. For the three months ended March 31, 2006, we incurred insurance expense related to premiums paid by EPCO of $2.7 million. At March 31, 2006 and December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.3 million.

On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming to an affiliate of Enterprise for $38.0 million. We recognized a gain of approximately $17.9 million on the sale of this asset (see Note 5).

In February 2006, we entered into a letter of intent with an affiliate of Enterprise related to the formation of a joint venture for the construction and financing of the expansion of the Jonah system. The letter of intent stipulates that Enterprise will be responsible for all activities related to the construction of the Jonah expansion, including advancing all amounts necessary to plan, engineer and construct the Jonah expansion (anticipated to be approximately $200.0 million). The amounts Enterprise advances to the project will constitute a subscription for an equity interest in the proposed joint venture. We have the option to return to Enterprise up to 100% of the amount of the subscription. If we return any portion of the subscription to Enterprise, our relative interests in the proposed joint venture will be adjusted accordingly. The proposed joint venture will terminate without liability to either party if we return 100% of the subscription (including carrying costs and expenses). Through March 31, 2006, Enterprise has incurred approximately $55.3 million related to this expansion.

NOTE 11. EMPLOYEE BENEFIT PLANS

Retirement Plans

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan. In addition, the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP") was a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participated. The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. The benefit formula for all eligible employees was a cash balance formula. Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits. The pay credits were based on a participant's salary, age and service. We used a December 31 measurement date for these plans.

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective December 31, 2005, all plan benefits accrued were frozen, participants received no additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, and plan participants have the option to receive their benefits either through a lump sum payment in 2006 or through an annuity. In April 2006, we received a determination letter from the IRS providing IRS approval of the plan termination. For those plan participants who elect to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005. Both the RCBP and SBP benefit payments are discussed below.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds

from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We expect to record additional settlement charges of approximately $4.0 million in 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants.

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the three months ended March 31, 2006 and 2005, were as follows (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Service cost benefit earned during the period	$ —	$ 1,005
Interest cost on projected benefit obligation	251	225
Expected return on plan assets	(121)	(300)
Amortization of prior service cost	—	2
Amortization of actuarial losses	35	—
Recognized net actuarial loss	—	10
Net pension benefits costs	$ 165	$ 942

Other Postretirement Benefits

We provided certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees became eligible for these benefits if they met certain age and service requirements at retirement, as defined in the plans. We provided a fixed dollar contribution, which did not increase from year to year, towards retired employee medical costs. The retiree paid all health care cost increases due to medical inflation. We used a December 31 measurement date for this plan.

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The employees participating in this plan at that time were transferred to DEFS, who is expected to provide postretirement benefits to these retirees. We recorded a one-time settlement to DEFS in the third quarter of 2005 of $0.4 million for the remaining postretirement benefits.

The components of net postretirement benefits cost for the TEPPCO OPB for the three months ended March 31, 2006 and 2005, were as follows (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Service cost benefit earned during the period	$ —	$ 49
Interest cost on accumulated postretirement benefit obligation	—	42
Amortization of prior service cost	—	32
Recognized net actuarial loss	—	4
Net postretirement benefits costs	$ —	$ 127

Effective June 1, 2005, the payroll functions performed by DEFS for our General Partner were transferred from DEFS to EPCO. For those employees who were receiving certain other postretirement benefits at the time of the acquisition of our General Partner by DFI, DEFS is expected to continue to provide these benefits to those employees. Effective June 1, 2005, EPCO began providing certain other postretirement benefits to those employees who became eligible for the benefits after June 1, 2005, and will charge those benefit related costs to us. As a result of these changes, we recorded a $1.2 million reduction in our other postretirement obligation in June 2005.

Estimated Future Benefit Contributions

We do not expect to make further contributions to our retirement plans and other postretirement benefit plans.

NOTE 12. SEGMENT INFORMATION

We have three reporting segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;
- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and transportation of NGLs.

The amounts indicated below as “Partnership and Other” relate primarily to intersegment eliminations and assets that we hold that have not been allocated to any of our reporting segments.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 7).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 7). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado.

The table below includes financial information by reporting segment for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 2,400,436	$ —	$ 2,400,436	$ (4,090)	$ 2,396,346
Operating revenues	74,067	11,146	56,377	141,590	(1,567)	140,023
Purchases of petroleum products	—	2,376,396	125	2,376,521	(5,356)	2,371,165
Operating expenses, including power	40,496	18,609	16,383	75,488	(301)	75,187
Depreciation and amortization expense	10,297	3,271	15,189	28,757	—	28,757
Gains on sales of assets	(7)	—	(1,371)	(1,378)	—	(1,378)
Operating income	23,281	13,306	26,051	62,638	—	62,638
Equity earnings (losses)	(1,266)	2,255	—	989	—	989
Other income – net	779	44	76	899	—	899
Earnings before interest from continuing operations	22,794	15,605	26,127	64,526	—	64,526
Discontinued operations	—	—	19,491	19,491	—	19,491
Earnings before interest	$ 22,794	$ 15,605	$ 45,618	$ 84,017	$ —	$ 84,017

	Three Months Ended March 31, 2005					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 1,385,067	$ —	$ 1,385,067	$ —	$ 1,385,067

Operating revenues	78,167	11,713	50,184	140,064	(1,340)	138,724
Purchases of petroleum products	—	1,372,430	—	1,372,430	(1,340)	1,371,090
Operating expenses, including power	37,186	15,445	13,725	66,356	—	66,356
Depreciation and amortization expense	9,561	3,501	12,549	25,611	—	25,611
(Gains) losses on sales of assets	(92)	1	(407)	(498)	—	(498)
Operating income	31,512	5,403	24,317	61,232	—	61,232
Equity earnings (losses)	(1,821)	5,915	—	4,094	—	4,094
Other income – net	149	75	42	266	—	266
Earnings before interest from continuing operations	29,840	11,393	24,359	65,592	—	65,592
Discontinued operations	—	—	1,124	1,124	—	1,124
Earnings before interest	$ 29,840	$ 11,393	$ 25,483	$ 66,716	$ —	$ 66,716

The following table provides total assets, capital expenditures and significant non-cash investing activities for each segment as of and for the periods ended March 31, 2006, and December 31, 2005 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
March 31, 2006:						
Total assets	$ 1,042,072	$ 1,551,395	$ 1,228,193	$ 3,821,660	$ (7,078)	$ 3,814,582
Capital expenditures	11,772	7,601	18,876	38,249	48	38,297
December 31, 2005:						
Total assets	$ 1,056,217	$ 1,353,492	$ 1,280,548	$ 3,690,257	$ (9,719)	$ 3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429

The following table reconciles the segments' earnings before interest to consolidated net income for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)
Earnings before interest	$ 84,017	$ 66,716
Interest expense – net	(21,143)	(19,287)
Net income	$ 62,874	$ 47,429

NOTE 13. COMMITMENTS AND CONTINGENCIES

Litigation

In the fall of 1999 and on December 1, 2000, the General Partner and TE Products were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* (including the General Partner and TE Products) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and TE Products). In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance, subject to applicable policy limits. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana. There are numerous plaintiffs identified in the action that are alleged to have suffered damages as a result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor. This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites. The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance. Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit. The plaintiffs have not stipulated the amount of damages that they are seeking in this suit. We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On August 5, 2005, we were named as a third-party defendant in a matter styled *ConocoPhillips, et al. v. BP Amoco Seaway Products Pipeline Company* as filed in the 55th Judicial District of Harris County, Texas. ConocoPhillips alleged a right to indemnity from BP Amoco Seaway Products Pipeline Company ("BP Amoco") for

tax liability incurred by ConocoPhillips as a result of the reverse merger of Seaway Pipeline Company (the "Original Seaway Partnership"). The reverse merger of the Original Seaway Partnership was undertaken in preparation for our purchase of ARCO Pipe Line Company pursuant to the Amended and Restated Purchase Agreement (the "Purchase Agreement") dated May 10, 2000, between us and Atlantic Richfield Company. BP Amoco claimed a right to indemnity from us under the Purchase Agreement if BP Amoco were to have any indemnity liability to ConocoPhillips. ConocoPhillips alleged the income tax liability to be approximately $4.0 million. On January 20, 2006, we entered into a settlement agreement with BP Amoco dismissing and resolving all of BP Amoco's claims. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. This revised demand includes amounts for environmental restoration not previously claimed by the plaintiffs. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Regulatory Matters

Our processing and fractionation plants, pipelines, and associated facilities are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations, and that the cost of compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial position. We cannot ensure, however, that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to

affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have material adverse effect on our business, financial position, results of operations and cash flows. At March 31, 2006, and December 31, 2005, we have an accrued liability of $2.3 million and $2.4 million, respectively, related to sites requiring environmental remediation activities.

On March 26, 2004, a decision in *ARCO Products Co., et al. v. SFPP*, Docket Nos. OR96-2-000 et al., was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act"). The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged. In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates. The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements such as rate base, tax rates and tax allowances, among others). The FERC did reject, however, the use of changes in tax rates and income tax allowances as stand-alone factors. Judicial review of that decision, which has been sought by a number of parties to the case, is currently pending before the U.S. Court of Appeals for the District of Columbia Circuit. We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision.

On July 20, 2004, the District of Columbia Circuit issued an opinion in *BP West Coast Products LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P., the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its income attributable to partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for the percentage of its net operating (pre-tax) income attributable to partnership units held by corporations, and was denied an income tax allowance equal to the percentage attributable to partnership units held by non-corporate partners. The court remanded the case back to the FERC for further review. Following the court's remand, on May 4, 2005, the FERC issued its Policy Statement on Income Tax Allowances, which permits regulated partnerships, limited liability companies and other pass-through entities an income tax allowance on their income attributable to any owner that has an actual or potential income tax liability on that income, regardless whether the owner is an individual or corporation. If there is more than one level of pass-through entities, the regulated company income must be traced to where the ultimate tax liability lies. The Policy Statement is to be applied in individual cases, and the regulated entity bears the burden of proof to establish the tax status of its owners. On December 16, 2005, the FERC issued the first of those decisions, in an order involving SFPP (the "SFPP Order"). The SFPP Order confirmed that a master limited partnership is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate. The SFPP Order remains subject to further administrative proceedings, including review by the FERC of compliance filings made by SFPP on March 7, 2006, as well as judicial review. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At March 31, 2006, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act ("CWA") arising out of this release, as well as three smaller spills at other locations in 2004 and 2005. We are in discussions with the DOJ regarding these matters. The settlement penalty proposed by the DOJ for these alleged violations of the CWA is a $3.0 million penalty, along with our commitment to implement additional spill prevention measures. We do not expect this settlement to have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but has resulted in claims by neighboring landowners, for which we anticipate a financial settlement in the range of $0.7 million to $0.8 million. In addition, the release resulted in a Corrective Action Order by the U.S. Department of Transportation. Among other requirements of this Order, we are required to reduce the operating pressure of Seaway by 20% until the completion of required corrective actions. We have a 50% ownership interest in Seaway, and any settlement should be covered by our insurance. We do not expect the completion of our obligations relating to the Colbert release to have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio. The incident resulted in the death of one of our employees; there were no other injuries. Repairs to the impacted facilities have been completed. On March 17, 2006, we received a citation from the Occupational Safety and Health Administration ("OSHA") arising out of this incident with a proposed penalty of less than $0.2 million. We are in settlement negotiations with OSHA representatives regarding this matter. We do not expect any settlement, fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of March 31, 2006, $150.0 million was outstanding under those credit facilities, of which $140.0 million expires in 2024, and $10.0 million expires in April 2007. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit facilities were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at March 31, 2006.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

One of our subsidiaries, TEPPCO Crude Oil, L.P. ("TCO"), has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely

payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees.

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of the General Partner may substantially lessen competition. The General Partner is cooperating fully with this investigation.

NOTE 14. COMPREHENSIVE INCOME

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on certain investments to be reported in a financial statement. As of and for the three months ended March 31, 2006, the components of accumulated other comprehensive income reflected on our consolidated balance sheets were composed of crude oil hedges and interest rate swaps. The crude oil hedges mature in December 2006. While the crude oil hedges are in effect, changes in their fair values, to the extent the hedges are effective, are recognized in accumulated other comprehensive income until they are recognized in net income in future periods. The interest rate swaps mature in January 2008, are related to our variable rate revolving credit facility, and are designated as cash flow hedges. While the interest rate swaps are in effect, changes in the fair values of the cash flow hedges, to the extent the hedges are effective, are recognized in accumulated other comprehensive income until the hedged interest costs are recognized in net income in future periods.

The accumulated balance of other comprehensive income related to our cash flow hedges are as follows (in thousands):

Balance at December 31, 2005	$ 11
Changes in fair values of crude oil cash flow hedges	236
Changes in fair values of interest rate cash flow hedges	1,671
Balance at March 31, 2006	$ 1,918

NOTE 15. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P., have issued guarantees of our debt securities. The guarantees are full, unconditional, and joint and several. These significant subsidiaries, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P., are collectively referred to as the "Guarantor Subsidiaries."

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates and periods indicated. For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting.

	March 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 19,323	$ 77,696	$ 995,790	$ (17,859)	$ 1,074,950
Property, plant and equipment – net	—	1,308,022	628,733	—	1,936,755
Equity investments	1,197,369	451,909	196,523	(1,498,425)	347,376
Intercompany notes receivable	1,162,479	—	—	(1,162,479)	—
Intangible assets	—	337,388	31,242	—	368,630
Other assets	6,947	23,008	56,916	—	86,871
Total assets	$ 2,386,118	$ 2,198,023	$ 1,909,204	$ (2,678,763)	$ 3,814,582
Liabilities and partners' capital					
Current liabilities	$ 21,629	$ 69,771	$ 973,854	$ (19,662)	$ 1,045,592
Long-term debt	1,164,072	382,982	—	—	1,547,054
Intercompany notes payable	—	637,079	525,401	(1,162,480)	—
Other long term liabilities	1,405	20,326	946	—	22,677
Total partners' capital	1,199,012	1,087,865	409,003	(1,496,621)	1,199,259
Total liabilities and partners' capital	$ 2,386,118	$ 2,198,023	$ 1,909,204	$ (2,678,763)	$ 3,814,582

	December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 40,977	$ 107,692	$ 789,486	$ (39,026)	$ 899,129
Property, plant and equipment – net	—	1,335,724	624,344	—	1,960,068
Equity investments	1,201,388	461,741	202,343	(1,505,816)	359,656
Intercompany notes receivable	1,134,093	—	—	(1,134,093)	—
Intangible assets	—	345,005	31,903	—	376,908
Other assets	5,532	22,170	57,075	—	84,777
Total assets	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538
Liabilities and partners' capital					
Current liabilities	$ 43,236	$ 140,743	$ 793,683	$ (40,451)	$ 937,211

Long-term debt	1,135,973	389,048	—	—	1,525,021
Intercompany notes payable	—	635,263	498,832	(1,134,095)	—
Other long term liabilities	1,422	14,564	950	—	16,936
Total partners' capital	1,201,359	1,092,714	411,686	(1,504,389)	1,201,370
Total liabilities and partners' capital	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538

	Three Months Ended March 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 115,060	$ 2,426,966	$ (5,657)	$ 2,536,369
Costs and expenses	—	75,764	2,405,002	(5,657)	2,475,109
Gains on sales of assets	—	(1,378)	—	—	(1,378)
Operating income	—	40,674	21,964	—	62,638
Interest expense – net	—	(14,377)	(6,766)	—	(21,143)
Equity earnings	62,874	16,263	2,255	(80,403)	989
Other income – net	—	823	76	—	899
Income from continuing operations	62,874	43,383	17,529	(80,403)	43,383
Income from discontinued operations	—	1,607	—	—	1,607
Gain on sale of discontinued operations	—	17,884	—	—	17,884
Net income	$ 62,874	$ 62,874	$ 17,529	$ (80,403)	$ 62,874

	Three Months Ended March 31, 2005 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 115,111	$ 1,410,020	$ (1,340)	$ 1,523,791
Costs and expenses	—	66,089	1,398,308	(1,340)	1,463,057
(Gains) losses on sales of assets	—	(499)	1	—	(498)
Operating income	—	49,521	11,711	—	61,232
Interest expense – net	—	(13,018)	(6,269)	—	(19,287)
Equity earnings	47,429	9,619	5,915	(58,869)	4,094
Other income – net	—	183	83	—	266
Income from continuing operations	47,429	46,305	11,440	(58,869)	46,305
Income from discontinued operations	—	1,124	—	—	1,124
Net income	$ 47,429	$ 47,429	$ 11,440	$ (58,869)	$ 47,429

	Three Months Ended March 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from operating activities					
Net income from continuing operations	$ 62,874	$ 43,383	$ 17,529	$ (80,403)	$ 43,383
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	22,701	6,056	—	28,757
Earnings in equity investments, net of distributions	4,018	11,644	6,202	(6,556)	15,308
Gains on sales of assets	—	(1,378)	—	—	(1,378)
Changes in assets and liabilities and other	(25,236)	(22,609)	(26,347)	25,215	(48,977)
Net cash provided by operating activities from continuing operations	41,656	53,741	3,440	(61,744)	37,093
Cash flows from discontinued operations	—	1,631	—	—	1,631
Net cash provided by operating activities	41,656	55,372	3,440	(61,744)	38,724
Cash flows from investing activities	—	59,377	(10,176)	(50,163)	(962)
Cash flows from financing activities	(37,792)	(114,811)	6,769	108,042	(37,792)
Net increase (decrease) in cash and cash equivalents	3,864	(62)	33	(3,865)	(30)
Cash and cash equivalents at beginning of period	1,978	62	45	(1,966)	119
Cash and cash equivalents at end of period	$ 5,842	$ —	$ 78	$ (5,831)	$ 89

	Three Months Ended March 31, 2005 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated

	(in thousands)				
Cash flows from operating activities					
Net income from continuing operations	$ 47,429	$ 46,305	$ 11,440	$ (58,869)	$ 46,305
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	19,577	6,034	—	25,611
Earnings (losses) in equity investments, net of distributions	11,229	2,213	(1,196)	(11,621)	625
(Gains) losses on sales of assets	—	(499)	1	—	(498)
Changes in assets and liabilities and other	(55,364)	(28,814)	(45,981)	72,642	(57,517)
Net cash provided by (used in) operating activities from continuing operations	3,294	38,782	(29,702)	2,152	14,526
Cash flows from discontinued operations	—	1,277	—	—	1,277
Net cash provided by (used in) operatingactivities	3,294	40,059	(29,702)	2,152	15,803
Cash flows from investing activities	—	9,088	(14,301)	(28,967)	(34,180)
Cash flows from financing activities	20,342	(62,243)	41,452	20,791	20,342
Net increase (decrease) in cash and cash equivalents	23,636	(13,096)	(2,551)	(6,024)	1,965
Cash and cash equivalents at beginning of period	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents at end of period	$ 27,752	$ 500	$ 275	$ (10,140)	$ 18,387

NOTE 16. RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

In the fourth quarter of 2005, we determined that our method of accounting for the $33.4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27.1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect. Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we had been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life. We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives. As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings. We restated previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004 in our Annual Report on Form 10-K for the year ended December 31, 2005. The effect of this restatement caused a $1.2 million reduction to net income as previously reported for the three months ended March 31, 2005. As a result, we are restating our previously reported consolidated financial statements for the three months ended March 31, 2005.

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt instruments. The restatement had no impact on total cash flows from operating activities, investing activities or financing activities. All amounts in the accompanying consolidated financial statements have been adjusted for this restatement.

We will continue to amortize the $30.0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life. The remaining $3.4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years. We will continue to amortize the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline.

The following tables summarize the impact of the restatement adjustment on previously reported income statement amounts and cash flow amounts for the three months ended March 31, 2005 (in thousands):

Income Statement Amounts:

	Three Months Ended March 31, 2005		
	As Previously Reported	Adjustment	As Restated
Equity earnings	$ 5,246	$ (1,152)	$ 4,094
Net income	48,581	(1,152)	47,429
Net Income Allocation:			
Limited Partner Unitholders	$ 34,566	$ (819)	$ 33,747
General Partner	14,015	(333)	13,682
Total net income allocated	$ 48,581	$ (1,152)	$ 47,429
Basic and diluted net income per Limited Partner Unit	$ 0.55	$ (0.01)	$ 0.54

Cash Flow Amounts:

	Three Months Ended March 31, 2005		
	As Previously Reported	Adjustment	As Restated
Cash flows from operating activities:			
Net income	$ 48,581	$ (1,152)	$ 47,429
Earnings in equity investments	(5,246)	1,152	(4,094)

NOTE 17. SUBSEQUENT EVENT

On April 20, 2006, EPCO submitted a proposal to the Audit and Conflicts Committee of our General Partner's Board of Directors to eliminate the General Partner's incentive distribution right to receive 50% of total cash distributions with respect to that portion of our quarterly distribution to limited partners that exceeds $0.45 per Unit. Under the terms of the proposal, the General Partner's incentive distribution rights would be capped at 25% of the total cash distributions with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to eliminate the 50% incentive distribution right, our General Partner would receive a number of newly-issued Units whose distributions would approximate the amount of actual cash distributions foregone by the General Partner from eliminating the 50% incentive distribution right at the time such change, if any, in the incentive distribution right is instituted. Based on the amount of cash distributions being received by the General Partner as of the date of the filing of this Report, the number of newly-issued Units issued to the General Partner would be approximately 13.0 million. The proposal, which includes other amendments to certain provisions of our Partnership Agreement, is subject to the approval of the Board of Directors upon the recommendation of the Audit and Conflicts Committee and, to the extent required under our Partnership Agreement or by the rules of the New York Stock Exchange, by our limited partners.

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

General

You should read the following review of our financial position and results of operations in conjunction with our Consolidated Financial Statements and the notes thereto. The Consolidated Financial Statements should be read in conjunction with the financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2005. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Overview of Critical Accounting Policies and Estimates.
- Overview of Business.
- Restatement of Consolidated Financial Statements.
- Results of Operations – Discusses material period-to-period variances in the consolidated statements of income.
- Financial Condition and Liquidity – Analyzes cash flows and financial position.
- Other Considerations – Addresses available sources of liquidity, trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.
- Recent Accounting Pronouncements.

Cautionary Note Regarding Forward-Looking Statements

The matters discussed in this Quarterly Report on Form 10-Q (this "Report") include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts are forward-looking statements. The words "proposed", "anticipate", "potential", "may", "will", "could", "should", "expect", "estimate", "believe", "intend", "plan", "seek" and similar expressions are intended to identify forward-looking statements. Without limiting the broader description of forward-looking statements above, we specifically note that statements included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of our business and operations, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. While we believe our expectations reflected in these forward-looking statements are reasonable, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other pipeline companies, changes in laws or regulations and other factors, many of which are beyond our control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products

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is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. We are also subject to regulatory factors such as the amounts we are allowed to charge our customers for the services we provide on our regulated pipeline systems. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations. Also note that we provide a cautionary discussion of risks and uncertainties under the captions "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Form 10-Q, as well as under the captions "Risk Factors", "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2005.

The forward-looking statements contained in this Report speak only as of the date hereof. Except as required by the federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to TEPPCO Partners, L.P. or any person acting on its behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Quarterly Report on Form 10-Q and in our future periodic reports filed with the Securities and Exchange Commission ("SEC"). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur. For additional discussion of such risks and uncertainties, see our Annual Report on Form 10-K for the year ended December 31, 2005, and other filings we have made with the SEC.

Overview of Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our Annual Report on Form 10-K for the year ended December 31, 2005. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: revenue and expense accruals, including accruals for power costs, property taxes and crude oil margins; environmental costs; asset impairment analysis related to property, plant and equipment; and amortization expense and asset impairment analysis related to goodwill and other intangible assets. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position and results of operations.

Overview of Business

Our corporate business strategy is to grow sustainable cash flow and cash distributions to our unitholders. The key elements of our strategy are to focus on internal growth prospects in order to increase pipeline system and terminal throughput, expand and upgrade existing assets and services and construct new pipelines, terminals and facilities; to target accretive and complementary acquisitions and expansion opportunities that provide attractive growth potential; to maintain an appropriate mix of assets; and to operate in a safe, efficient and environmentally responsible manner.

Certain factors are key to our operations. These include the safe, reliable and efficient operation of the pipelines and facilities that we own or operate while meeting the regulations that govern the operation of our assets and the costs associated with such regulations. We are also focused on our continued growth through expansion of the assets that we own and through the acquisition of assets that complement our current operations. We operate and report in three business segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;

- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and

- Our Midstream Segment, which is engaged in the gathering of natural gas, transportation of NGLs and fractionation of NGLs.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 7 in the Notes to the Consolidated Financial Statements).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 7 in the Notes to the Consolidated Financial Statements). Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado.

We continue to build a base for long-term growth by pursuing new business opportunities, increasing throughput on our pipeline systems, constructing new pipeline and gathering systems, and expanding and upgrading our existing infrastructure. We remain confident that our business strategy will provide continued growth in earnings and cash distributions. This growth potential is based on, among other things:

- Continued development and expansion of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment. Through an additional Jonah expansion, which should be completed in the fourth quarter of 2006, we expect to increase the capacity to 2 billion cubic feet per day.
- Expanding our Downstream Segment gathering capacity of refined products along the upper Texas Gulf Coast.
- Utilizing available Downstream Segment system capacity of Centennial to move refined products to Midwest market areas.
- Expanding our Downstream Segment system delivery capability of gasoline and diesel fuel in the Indianapolis and Chicago market areas.

- Integrating 2005 acquisitions by our Upstream Segment into our existing asset base.
- Expanding our West Texas system and storage capacity at Cushing in our Upstream Segment.
- Adding new volumes and improving the operating efficiency of the Val Verde system in our Midstream Segment in New Mexico's San Juan Basin, through new connections of conventional and Colorado coal seam gas.

- Increasing throughput on our Midstream Segment NGL systems.
- Pursuing acquisitions or organic growth projects in any of our business segments that would complement our current operations.

For a discussion of important factors that could affect our growth, please read "-Cautionary Note Regarding Forward-Looking Statements" in this Report and "Risk Factors" in this Report and our Annual Report on Form 10-K for the year ended December 31, 2005.

Our Upstream Segment's performance for 2006 will be impacted by a decrease in our participation ratio in the revenue and expense of Seaway, in accordance with the Seaway Crude Pipeline Company Partnership Agreement. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. Our share of revenue and expense of Seaway is 47% for 2006 (see Note 7 in the Notes to the Consolidated Financial Statements).

On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming to an affiliate of Enterprise for $38.0 million. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. The sales proceeds will be used to fund organic growth projects, retire debt and for other general partnership purposes. The margin of the Midstream Segment, calculated as revenues generated from the processing arrangements at the Pioneer plant, less purchases of gas, will be reduced in 2006 as a result of the sale of the Pioneer plant (see Note 5 in the Notes to the Consolidated Financial Statements). Operating results of the Pioneer plant for all periods presented are shown as discontinued operations.

We expect to further expand the Jonah system. In February 2006, we entered into a letter of intent with an affiliate of Enterprise related to the formation of a joint venture for the construction and financing of the expansion of the Jonah system. The letter of intent stipulates that Enterprise will be responsible for all activities related to the construction of the Jonah expansion, including advancing all amounts necessary to plan, engineer and construct the Jonah expansion. We anticipate that the total funds needed for this expansion project will be approximately $200.0 million, and that the expanded assets will be placed in service in late 2006. The amounts Enterprise advances to the project will constitute a subscription for an equity interest in the proposed joint venture. We have the option to return to Enterprise up to 100% of the amount of the subscription. If we return any portion of the subscription to Enterprise, our relative interests in the proposed joint venture will be adjusted accordingly. The proposed joint venture will terminate without liability to either party if we return 100% of the subscription (including carrying costs and expenses).

Consistent with our business strategy, we continuously evaluate possible acquisitions of assets that would complement our current operations, including assets which, if acquired, would have a material effect on our financial position, results of operations or cash flows.

Changes in Leadership

On April 5, 2006, the Board of Directors of our General Partner elected Jerry E. Thompson as President, Chief Executive Officer and a director of the Company, effective April 11, 2006. Mr. Thompson, age 56, was previously chief operating officer of CITGO Petroleum Corporation ("CITGO") from 2003 to March 2006, when he retired. Mr. Thompson joined CITGO in 1971 and advanced from a process engineer to positions of increasing responsibilities in the operations, supply and logistics, business development, planning and financial aspects of CITGO. He was elected vice president of CITGO's refining business in 1987 and as its senior vice president in 1998. Mr. Thompson will serve as the principal executive officer of the Company.

EPCO Proposal

On April 20, 2006, EPCO submitted a proposal to the Audit and Conflicts Committee of our General Partner's Board of Directors to eliminate the General Partner's incentive distribution right to receive 50% of total cash distributions with respect to that portion of our quarterly distribution to limited partners that exceeds $0.45 per Unit, among other things. For additional information regarding this proposal, please read Note 17 in the Notes to the Consolidated Financial Statements.

Restatement of Consolidated Financial Statements

In the fourth quarter of 2005, we determined that our method of accounting for the $33.4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27.1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect. Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we had been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life. We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives. As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings. We restated previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004 in our Annual Report on Form 10-K for the year ended December 31, 2005. The effect of this restatement caused a $1.2 million reduction to net income as previously reported for the three months ended March 31, 2005. As a result, we are restating our previously reported consolidated financial statements for the three months ended March 31, 2005 (see Note 16 in the Notes to the Consolidated Financial Statements).

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt instruments. The restatement had no impact on total cash flows from operating activities, investing activities or financing activities. All amounts in the accompanying consolidated financial statements have been adjusted for this restatement.

We will continue to amortize the $30.0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life. The remaining $3.4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years. We will continue to amortize the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline.

Results of Operations

The following table summarizes financial information by business segment for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)
Operating revenues:		
Downstream Segment	$ 74,067	$ 78,167
Upstream Segment	2,411,582	1,396,780
Midstream Segment	56,377	50,184
Intercompany eliminations	(5,657)	(1,340)
Total operating revenues	2,536,369	1,523,791
Operating income:		
Downstream Segment	23,281	31,512
Upstream Segment	13,306	5,403
Midstream Segment	26,051	24,317
Total operating income	62,638	61,232
Earnings before interest:		
Downstream Segment	22,794	29,840
Upstream Segment	15,605	11,393
Midstream Segment	26,127	24,359
Interest expense	(24,402)	(20,389)
Interest capitalized	3,259	1,102
Income from continuing operations	43,383	46,305
Discontinued operations	19,491	1,124
Net income	$ 62,874	$ 47,429

Below is a detailed analysis of the results of operations, including reasons for changes in results, for each of our operating segments.

Downstream Segment

The following table provides financial information for the Downstream Segment for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)	Increase (Decrease)
Revenues:			
Transportation – Refined products	$ 31,799	$ 34,965	$ (3,166)
Transportation – LPGs	29,421	32,231	(2,810)
Other	12,847	10,971	1,876
Total operating revenues	74,067	78,167	(4,100)
Costs and Expenses:			
Operating, general and administrative	28,596	26,615	1,981
Operating fuel and power	9,305	7,660	1,645
Depreciation and amortization	10,297	9,561	736
Taxes – other than income taxes	2,595	2,911	(316)
Gains on sales of assets	(7)	(92)	85
Total costs and expenses	50,786	46,655	4,131
Operating income	23,281	31,512	(8,231)
Equity losses	(1,266)	(1,821)	555
Other income – net	779	149	630

Earnings before interest	$ 22,794	$ 29,840	$ (7,046)

The following table presents volumes delivered in barrels and average tariff per barrel for the three months ended March 31, 2006 and 2005 (in thousands, except tariff information):

	Three Months Ended March 31,		Percentage Increase (Decrease)
	2006	2005	
Volumes Delivered:			
Refined products	35,808	38,595	(7)%
LPGs	12,840	14,801	(13)%
Total	48,648	53,396	(9)%
Average Tariff per Barrel:			
Refined products	$ 0.89	$ 0.91	(2)%
LPGs	2.29	2.18	5%
Average system tariff per barrel	$ 1.26	$ 1.26	—

Three Months Ended March 31, 2006 Compared with Three Months Ended March 31, 2005

Revenues from refined products transportation decreased $3.2 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to an overall decrease of 7% in the refined products volumes delivered. Volume decreases were due to decreased demand for products supplied from the U.S. Gulf Coast into Midwest markets compared with unusually high demand in the first quarter of 2005 due to refinery downtime in Chicago, Illinois. Refined products volumes were impacted by unfavorable differentials for motor fuels and lower jet fuel demand during the three months ended March 31, 2006, compared with the three months ended March 31, 2005. The decrease in demand for U.S. Gulf Coast source products also resulted in lower deliveries of products on Centennial. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. As a result, Centennial has provided our system with additional pipeline capacity for movement of products originating in the U.S. Gulf Coast area. Prior to

the construction of Centennial, deliveries on our pipeline system were limited by our pipeline capacity, and transportation services for our customers were allocated in accordance with a proration policy. With this incremental pipeline capacity and our supporting lease of pipeline capacity, our previously constrained system has expanded deliveries in markets both south and north of Creal Springs, Illinois. Movement of TEPPCO product via the Centennial lease to the north end of our system permits expanded supply capability on the TEPPCO system for delivery to the south end of our system. Increased movements of refined products on Centennial has resulted in a decrease in the refined products average rate per barrel; however, utilizing Centennial for refined products movements allows us to increase movements of long-haul propane volumes.

Revenues from LPGs transportation decreased $2.8 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of warmer than normal winter weather and decreased short-haul propane deliveries to U.S. Gulf Coast petrochemical customers in the first quarter of 2006.

Other operating revenues increased $1.9 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to increased rental revenues from leasing storage capacity on pipeline assets acquired in July 2005, and higher refined products excess inventory fees, partially offset by lower volumes of product inventory sales.

Costs and expenses increased $4.1 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to increased operating, general and administrative expenses, increased operating fuel and power, increased depreciation and amortization expense and lower gains on the sales of assets in the current period, partially offset by decreased taxes – other than income taxes. Operating, general and administrative expenses increased primarily due to a $1.4 million increase in pipeline operating costs primarily as a result of asset acquisitions in 2005, a $1.2 million increase related to the retirement of an executive in February 2006, as well as higher insurance premiums, product measurement and settlement losses and transition costs. These increases were partially offset by a $1.9 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $0.5 million decrease in rental expense from the Centennial pipeline capacity lease agreement. Operating fuel and power increased $1.6 million primarily due to adjustments to power accruals and higher power rates. Depreciation and amortization expense increased $0.7 million primarily due to a higher asset base in the 2006 period. Taxes – other than income taxes decreased due to decreases in property tax accruals.

Net losses from equity investments decreased for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, as shown below (in thousands):

	Three Months Ended March 31,		Increase (Decrease)
	2006	2005 (as restated)	
Centennial	$ (3,913)	$ (4,450)	$ 537
MB Storage	2,651	2,634	17
Other	(4)	(5)	1
Total equity losses	$ (1,266)	$ (1,821)	$ 555

Equity losses in Centennial decreased $0.5 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to lower amortization expense on the portion of TE Products' excess investment in Centennial resulting from lower transportation volumes in the current period, partially offset by lower transportation revenues and volumes primarily due to warmer than normal winter weather in the Northeast. Equity earnings in MB Storage were virtually unchanged for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, with higher revenues offset by higher operating costs.

Other income – net increased $0.6 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to higher interest income earned on a capital lease.

Upstream Segment

The following table provides financial information for the Upstream Segment for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005 (as restated)	Increase (Decrease)
Revenues:			
Sales of petroleum products	$ 2,400,436	$ 1,385,067	$ 1,015,369
Transportation – Crude oil	8,923	9,172	(249)
Other	2,223	2,541	(318)
Total operating revenues	2,411,582	1,396,780	1,014,802
Costs and Expenses:			
Purchases of petroleum products	2,376,396	1,372,430	1,003,966
Operating, general and administrative	14,951	12,816	2,135
Operating fuel and power	2,193	1,228	965
Depreciation and amortization	3,271	3,501	(230)
Taxes – other than income taxes	1,465	1,401	64
Losses on sales of assets	—	1	(1)
Total costs and expenses	2,398,276	1,391,377	1,006,899
Operating income	13,306	5,403	7,903
Equity earnings	2,255	5,915	(3,660)
Other income – net	44	75	(31)
Earnings before interest	$ 15,605	$ 11,393	$ 4,212

Information presented in the following table includes the margin of the Upstream Segment, which may be viewed as a non-GAAP (Generally Accepted Accounting Principles) financial measure under the rules of the SEC. We calculate the margin of the Upstream Segment as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil. We believe that margin is a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the level of volumes marketed and prices for products marketed. Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment as we believe margin is a better indicator of performance than operating income, as operating, general and administrative expenses, operating fuel and power and depreciation expense are not directly related to the margin activities. Margin and volume information for the three months ended March 31, 2006 and 2005 is presented below (in thousands, except per barrel and per gallon amounts):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	Percentage Increase (Decrease)
Margins: (1)			
Crude oil transportation	$ 15,768	$ 14,153	11%
Crude oil marketing	12,786	3,476	268%
Crude oil terminaling	2,278	2,423	(6)%
Lubrication oil sales	2,131	1,757	21%
Total margin	$ 32,963	$ 21,809	51%
Total barrels:			
Crude oil transportation	22,328	23,754	(6)%
Crude oil marketing	52,941	44,294	20%
Crude oil terminaling	24,443	27,119	(10)%
Lubrication oil volume (total gallons)	3,855	4,172	(8)%
Margin per barrel:			
Crude oil transportation	$ 0.706	$ 0.596	19%
Crude oil marketing	0.242	0.078	208%
Crude oil terminaling	0.093	0.089	4%
Lubrication oil margin (per gallon)	0.553	0.421	31%

(1) Margins in this table are presented prior to the elimination of intercompany sales, revenues and purchases between TEPPCO Crude Oil, L.P. and TEPPCO Crude Pipeline, L.P.

The following table reconciles the Upstream Segment margin to operating income in the consolidated statements of income using the information presented in the tables above, in the consolidated statements of income and in the statements of income in Note 12 in the Notes to the Consolidated Financial Statements (in thousands):

	Three Months Ended March 31,	
	2006	2005
Sales of petroleum products	$ 2,400,436	$ 1,385,067
Transportation – Crude oil	8,923	9,172
Less: Purchases of petroleum products	(2,376,396)	(1,372,430)
Total margin	32,963	21,809
Other operating revenues	2,223	2,541
Net operating revenues	35,186	24,350
Operating, general and administrative	14,951	12,816
Operating fuel and power	2,193	1,228
Depreciation and amortization	3,271	3,501
Taxes – other than income taxes	1,465	1,401
Losses on sales of assets	—	1
Operating income	$ 13,306	$ 5,403

Three Months Ended March 31, 2006 Compared with Three Months Ended March 31, 2005

Our margin increased $11.2 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005. Crude oil marketing margin increased $9.3 million primarily due to a 20% increase in volumes marketed primarily resulting from the acquisitions of assets in April 2005, favorable market conditions and lower unrealized losses related to marking crude oil physical swaps to market compared to the 2005 period. Crude oil transportation margin increased $1.6 million primarily due to increased transportation volumes on our

South Texas system due to the acquisition of crude oil pipeline assets in April 2005, and increased revenues on our Red River system as a result of increased movements on higher tariff segments, partially offset by a decrease in low margin transportation volumes on the Red River system and other crude oil transportation systems. Lubrication oil sales margin increased $0.4 million due to an increase in the margin per gallon on product sales, partially offset by slightly lower volumes.

Other operating revenues of the Upstream Segment decreased $0.3 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to lower revenues from documentation and other services to support customers' trading activity at Midland, Texas, and Cushing, Oklahoma, in the first quarter of 2006 as a result of consolidations of trading companies.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $3.0 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to increased operating, general and administrative expenses, increased operating fuel and power and increased taxes – other than income taxes, partially offset by decreased depreciation and amortization expense. Operating, general and administrative expenses increased $2.1 million from the prior year period primarily due to a $1.4 million increase in pipeline operating and maintenance expense as a result of acquisitions and the continued integration of Genesis assets into our system, a $0.5 million increase in environmental assessment and remediation costs, a $0.4 million increase in insurance premiums and a $0.4 million increase in general and administrative consulting services and supplies and expenses. These increases were partially offset by a $0.6 million decrease in product measurement losses. Operating fuel and power increased $1.0 million primarily as a result of higher power rates, partially offset by lower transportation volumes. Taxes – other than income taxes increased $0.1 million due to increases in property tax accruals and a higher asset base in 2006. Depreciation and amortization expense decreased $0.2 million as a result of assets retired to depreciation expense during the 2005 period.

Equity earnings from our investment in Seaway decreased $3.7 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005. Our equity earnings in Seaway were reduced by a decrease in our participation ratio in the revenue and expense of Seaway. Our sharing ratio for 2005 was 60%, while for the full year of 2006, it is 47% of the revenue and expense of Seaway (see Note 7 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher pipeline inspection and repair costs, higher power costs and higher operating costs attributable to a pipeline release in May 2005, partially offset by higher long-haul transportation volumes.

After Seaway's pipeline release in May 2005, the maximum operating pressure on the pipeline system has been reduced by 20% until the cause of the failure was determined and any required corrective measures are implemented. A study of the failed pipe was performed by independent metallurgical experts who determined that the pipe failed due to damage that occurred during rail shipment associated with its installation thirty years ago. The corrective actions include running a high definition inspection tool through the pipe to determine if there are any other sections of pipe that have similar damage. This approach is consistent with directives from the United States Department of Transportation's Office of Pipeline Safety in past failures of this type. The inspection tool has been run and the resulting data is currently being analyzed. We expect Seaway to be operating at reduced maximum pressure through the second quarter of 2006. As a result of operating at reduced maximum pressure, during the third quarter of 2005, we began using a drag reducing agent to increase the flow of product through the pipeline system. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. At this time, we do not believe the reduced pressure will have a material adverse effect on our financial position, results of operations or cash flows.

Midstream Segment

The following table provides financial information for the Midstream Segment for the three months ended March 31, 2006 and 2005 (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	Increase (Decrease)
Revenues:			
Sales of petroleum products	$ —	$ —	$ —
Gathering – Natural Gas	41,375	36,560	4,815
Transportation – NGLs	10,653	10,219	434
Other	4,349	3,405	944
Total operating revenues	56,377	50,184	6,193
Costs and Expenses:			
Purchases of petroleum products	125	—	125
Operating, general and administrative	12,333	10,449	1,884
Operating fuel and power	2,799	2,182	617
Depreciation and amortization	15,189	12,549	2,640
Taxes – other than income taxes	1,251	1,094	157
Gains on sales of assets	(1,371)	(407)	(964)
Total costs and expenses	30,326	25,867	4,459
Operating income	26,051	24,317	1,734
Other income – net	76	42	34
Earnings before interest from continuing operations	26,127	24,359	1,768
Income from discontinued operations	1,607	1,124	483
Gain on sale of discontinued operations	17,884	—	17,884
Earnings before interest	$ 45,618	$ 25,483	$ 20,135

The following table presents volume and average rate information for the three months ended March 31, 2006 and 2005 (in thousands, except average fee and average rate amounts):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	Percentage Increase (Decrease)
Gathering – Natural Gas – Jonah:			
Million cubic feet (“MMcf”)	108,669	97,350	12%
Million British thermal units (“MMBtu”)	120,007	107,300	12%
Average fee per MMBtu	$ 0.206	$ 0.189	9%
Gathering – Natural Gas – Val Verde:			
MMcf	45,350	43,325	5%
MMBtu	39,392	38,088	5%
Average fee per MMBtu	$ 0.418	$ 0.428	(2)%
Transportation – NGLs:			
Thousand barrels	15,866	13,836	15%
Average rate per barrel	$ 0.671	$ 0.739	(9)%
Fractionation – NGLs:			
Thousand barrels	1,153	1,139	1%
Average rate per barrel	$ 1.486	$ 1.647	(10)%
Sales – Condensate:			
Thousand barrels	24.7	27.9	(11)%
Average rate per barrel	$ 63.54	$ 48.11	32%

Three Months Ended March 31, 2006 Compared with Three Months Ended March 31, 2005

Revenues from the gathering of natural gas increased $4.8 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005. Natural gas gathering revenues from the Jonah system increased $4.4 million and volumes gathered increased 11.3 billion cubic feet (“Bcf”) for the three months ended March 31, 2006, primarily due to the expansion of the Jonah system in 2005. The Phase IV expansion project on Jonah was completed in February 2006. The expansion increased the system capacity of Jonah to 1.5 Bcf per day with the addition of 33,000 horsepower of compression and approximately 50 miles of pipeline. Jonah’s average natural gas gathering rate increased primarily due to lower system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $0.4 million and volumes gathered increased 2.0 Bcf for the three months ended March 31, 2006, primarily due to increased volumes from a natural gas connection on the Val Verde system, better performance from coal seam infill wells and increased volumes from temporary interconnects with third party gatherers. Val Verde’s average natural gas gathering rate decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system’s average rates.

Revenues from the transportation of NGLs increased $0.4 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to increases in volumes transported on the Chaparral, Panola and Dean Pipelines. The average NGL transportation rate per barrel decreased primarily due to an increase in short-haul movements on the Chaparral Pipeline and a decrease in long-haul movements on the Panola Pipeline.

Other operating revenues increased $0.9 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to a new pipeline capacity lease on the Chaparral Pipeline, higher revenues on the Panola Pipeline and higher condensate sales on Jonah.

Costs and expenses increased $4.4 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to increased depreciation and amortization expense, increased operating, general and administrative expense, increased operating fuel and power and increased taxes – other than income taxes, partially offset by a net gain recorded on the sale of assets. Depreciation expense increased $1.5 million primarily due to an increase on Jonah as a result of assets placed into service from the Phase IV expansion. Amortization expense increased primarily due to an increase of $1.0 million on Val Verde due to higher volumes on contracts included in the intangible assets in the 2006 period. On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. Revisions to these estimates may occur as additional production information is made available to us. Operating, general and administrative expense increased $1.9 million primarily due to an increase in general and administrative expenses, transition costs, an increase in insurance expense and imbalance valuations. Operating fuel and power increased $0.6 million primarily due to increased volumes and higher power costs in the 2006 period. Taxes other than income taxes increased $0.2 million primarily due to adjustments to property tax accruals and a higher asset base in 2006. During the three months ended March 31, 2006 and 2005, gains of $1.4 million and $0.4 million, respectively, were recognized on the sales of various equipment at Val Verde.

Discontinued Operations

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming to an affiliate of Enterprise for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party. The sales proceeds will be used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction are estimated to be approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months ended March 31, 2006 and 2005, are presented below (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Sales of petroleum products	$ 3,810	$ 2,142
Other	921	672
Total operating revenues	4,731	2,814
Purchases of petroleum products	2,861	1,370
Operating, general and administrative	182	138
Depreciation and amortization	51	152
Taxes – other than income taxes	30	30
Total costs and expenses	3,124	1,690
Net income from discontinued operations	$ 1,607	$ 1,124

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Jonah Pioneer plant increased $0.2 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to increased NGL prices. The Pioneer gas processing plant was completed during the first quarter of 2004, as a part of Jonah's Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allowed the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah received a fee for its processing services. Under the fee plus keep-whole election, Jonah received a lower fee for its processing services, retained and sold the NGLs extracted during the process and delivered to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sold the NGLs it retained and purchased gas to replace the equivalent energy removed in the liquids. For the 2005 and 2006 periods, the producers elected the fee plus keep-whole arrangement.

Interest Expense and Capitalized Interest

Interest expense increased $4.0 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility.

Capitalized interest increased $2.2 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At March 31, 2006, we had a working capital surplus of $29.4 million, while at December 31, 2005, we had a working capital deficit of $38.1 million. At March 31, 2006, we had approximately $253.1 million in available borrowing capacity under our revolving credit facility to cover any working capital needs. Cash flows for the three months ended March 31, 2006 and 2005, were as follows (in millions):

	Three Months Ended March 31,	
	2006	2005 (as restated)
Cash provided by (used in):		
Operating activities	$ 38.7	$ 15.8
Investing activities	(1.0)	(34.2)
Financing activities	(37.8)	20.3

Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2006 and 2005, was comprised of the following (in millions):

	Three Months Ended March 31,	
	2006	2005 (as restated)
Net income from continuing operations	$ 43.4	$ 46.3
Depreciation and amortization	28.8	25.6
Losses in equity investments	(1.0)	(4.1)
Distributions from equity investments	16.3	4.7
Gains on sales of assets	(1.4)	(0.5)
Non-cash portion of interest expense	0.4	0.4
Cash used in working capital and other	(49.4)	(57.9)
Net cash provided by operating activities from continuing operations	37.1	14.5
Cash flows from discontinued operations	1.6	1.3
Net cash provided by operating activities	$ 38.7	$ 15.8

Net cash provided by operating activities from continuing operations increased $22.6 million for the three months ended March 31, 2006, compared with the three months ended March 31, 2005, primarily due to an increase of $11.6 million in distributions received from our equity investments in Seaway and MB Storage, the timing of cash disbursements and cash receipts for working capital components, higher depreciation and amortization expense and decreased losses from equity investments. For a discussion of changes in earnings before interest, depreciation and amortization expense, equity earnings and consolidated interest expense – net, see Results of Operations for the Downstream Segment, Upstream Segment and Midstream Segment in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Net cash from operating activities for the three months ended March 31, 2006 and 2005, included interest payments, net of amounts capitalized, of $38.5 million and $36.8 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2006, we expect interest payments on our fixed rate Senior Notes to be approximately $78.0 million. We expect to pay our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $1.0 million for the three months ended March 31, 2006, and were comprised of $38.3 million of capital expenditures and $1.7 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures, partially offset by $39.0 million in net cash proceeds from asset sales in our Midstream Segment, of which $38.0 million related to cash proceeds received from the sale of the Pioneer plant. Cash flows used in investing activities totaled $34.2 million for the three months ended March 31, 2005, and were comprised of $27.6 million of capital expenditures and $7.1 million for the acquisition of crude oil assets acquired in the first quarter of 2005, partially offset by $0.5 million in net cash proceeds from an asset sale in our Midstream Segment.

Financing Activities

Cash flows used in financing activities totaled $37.8 million for the three months ended March 31, 2006, and were comprised of $66.9 million of distributions paid to our General Partner and to unitholders, partially offset by $29.1 million in borrowings, net of repayments, from our revolving credit facility. Cash flows provided by financing activities totaled $20.3 million for the three months ended March 31, 2005, and were comprised of $79.0

million in borrowings, net of repayments, from our revolving credit facility, partially offset by $58.7 million of distributions paid to our General Partner and to unitholders.

We paid cash distributions of $66.9 million ($0.675 per Unit) and $58.7 million ($0.6625 per Unit) during each of the three months ended March 31, 2006 and 2005, respectively. Additionally, we declared a cash distribution of $0.675 per Unit for the quarter ended March 31, 2006. We will pay the distribution of $66.9 million on May 5, 2006, to unitholders of record on April 28, 2006.

Other Considerations

Universal Shelf

We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof.

In the May 2005 equity offering, we issued $279.2 million of equity securities, leaving $1.7 billion available under this shelf registration at March 31, 2006, subject to customary marketing terms and conditions.

Credit Facilities

We have in place an unsecured revolving credit facility for up to $700.0 million ("Revolving Credit Facility"), which may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions. The Revolving Credit Facility expires on December 13, 2010. Interest is payable at an applicable margin above either the lender's base rate or LIBOR. At March 31, 2006, $435.0 million was outstanding under the facility, and we had $253.1 million of available borrowing capacity, which includes $11.9 million of outstanding letters of credit. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other restrictive covenants in the credit agreement limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash, incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. At March 31, 2006, we were in compliance with the covenants of the Revolving Credit Facility.

Future Capital Needs and Commitments

We estimate that capital expenditures for 2006, excluding acquisitions and capital expenditures related to the proposed joint venture with an affiliate of Enterprise discussed below, will be approximately $231.8 million (including $6.0 million of capitalized interest). We expect to spend approximately $161.5 million for revenue generating projects. Capital spending on revenue generating projects and facility improvements will include approximately $74.9 million for the expansion of our Downstream Segment facilities. We expect to spend $24.0 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $62.6 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $39.8 million to sustain existing operations, including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $24.5 million to improve operational efficiencies and reduce costs among all of our business segments. During 2006, TE Products may be required to contribute cash to Centennial to cover capital expenditures, acquisitions or other operating needs and to MB Storage to cover significant capital expenditures or additional acquisitions. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

The construction of the Jonah expansion is expected to be completed through a proposed joint venture between us and Enterprise, relating to the construction and financing of the Jonah expansion. In February 2006, we entered into a letter of intent with an affiliate of Enterprise related to this expansion, which is anticipated to cost approximately $200.0 million. For additional information, see "-Overview of Business" above.

Liquidity Outlook

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and to complete the Jonah expansion, revenue generating expenditures, interest payments on our Senior Notes and Revolving Credit Facility, distributions to our General Partner and unitholders and acquisitions of new assets or businesses. Our cash requirements for 2006 are expected to be funded through operating cash flows and our arrangement with an affiliate of Enterprise under the pending joint venture agreement related to the Jonah expansion. Long-term cash requirements for expansion projects, acquisitions and debt repayments are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, joint ventures and possibly the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Off-Balance Sheet Arrangements

We do not rely on off-balance sheet borrowings to fund our acquisitions. We have no material off-balance sheet commitments for indebtedness other than the limited guaranty of Centennial debt, the limited guarantee of Centennial catastropic events as discussed below and an outstanding letter of credit. In addition, we have entered into various leases covering assets utilized in several areas of our operations.

Centennial entered into credit facilities totaling $150.0 million, and as of March 31, 2006, $150.0 million was outstanding under those credit facilities, of which $140.0 million expires in 2024, and $10.0 million expires in April 2007. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit facilities were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at March 31, 2006.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

One of our subsidiaries, TEPPCO Crude Oil, L.P. ("TCO"), has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees.

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of March 31, 2006 (in millions):

	Amount of Commitment Expiration Per Period				
	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Revolving Credit Facility	$ 435.0	$ —	$ —	$ 435.0	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	180.0	—	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Interest payments (3)	791.4	100.4	189.2	171.0	330.8
Debt and interest subtotal	2,316.4	100.4	369.2	606.0	1,240.8
Operating leases (4)	82.4	18.7	28.1	14.1	21.5
Capital expenditure obligations (5)	3.1	3.1	—	—	—
Standby letter of credit (6)	11.9	11.9	—	—	—
Other liabilities and deferred credits (7)	9.7	—	9.2	0.3	0.2
Total	$ 2,423.5	$ 134.1	$ 406.5	$ 620.4	$ 1,262.5

(1) Obligations of TE Products.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At March 31, 2006, the 7.51% Senior Notes include an adjustment to decrease the fair value of the debt by $7.0 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625% Senior Notes due 2012. At March 31, 2006, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $31.3 million. At March 31, 2006, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.2 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

(3) Includes interest payments due on our Senior Notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amount calculated on the Revolving Credit Facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(4) Includes a pipeline capacity lease with Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the three months ended March 31, 2006, TE Products exceeded the minimum throughput requirements on the lease agreement.

(5) Includes accruals for costs incurred but not yet paid relating to capital projects.

(6) At March 31, 2006, we had outstanding an $11.9 million standby letter of credit in connection with crude oil purchased in the first quarter of 2006. This amount is expected to be paid during the second quarter of 2006.

(7) Excludes approximately $8.7 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $4.3 million related to our estimated long-term portion of our obligation under a catastrophic event guarantee for Centennial. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

We expect to repay the long-term, senior unsecured obligations and bank debt through the issuance of additional long-term senior unsecured debt at the time the 2008, 2012, 2013 and 2028 debt matures, issuance of additional equity, with proceeds from dispositions of assets, cash flow from operations or any combination of the above items.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the three months ended March 31, 2006, crude oil purchases averaged approximately $792.1 million per month.

Our senior unsecured debt is rated BBB- by Standard and Poors (“S&P”) and Baa3 by Moody’s Investors Service (“Moody’s”). S&P assigned this rating on June 14, 2005, following its review of the ownership structure, corporate governance issues, and proposed funding after the acquisition of the General Partner by DFI. Both ratings are with a stable outlook. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating. The senior unsecured debt of our subsidiary, TE Products, is also rated BBB- by S&P and Baa3 by Moody's. Both ratings are with a stable outlook and were reaffirmed during the first quarter of 2006.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 1 in the Notes to the Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For additional discussion of our exposure to market risks, please refer to "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2005.

Commodity Risk

We may be exposed to market risk through changes in crude oil commodity prices and interest rates. We do not have foreign exchange risks. Our Risk Management Committee has established policies to monitor and control these market risks. The Risk Management Committee is comprised, in part, of senior executives of the Company.

We seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. On the majority of our crude oil derivative contracts, we take the normal purchase and normal sale exclusion in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*.

On a small portion of our crude oil marketing business, we enter into derivative contracts such as swaps and other business hedging devices for which we cannot take the normal purchase and normal sale exclusion. Generally, hedge accounting is elected. The terms of these contracts are typically one year or less. The purpose is to balance our position or lock in a margin and, as such, the derivative contracts do not expose us to additional significant market risk. For derivatives where hedge accounting is elected, the effective portion of changes in fair value are recorded in other comprehensive income and reclassified into earnings as such transactions are settled. For derivatives where hedge accounting is not elected, we mark these transactions to market and the changes in the fair value are recognized in current earnings. This results in some financial statement variability during quarterly

periods; however, any unrealized gains and losses reflected in the financial statements related to marking these transactions to market are offset by realized gains and losses in different quarterly periods when the transactions are settled.

At March 31, 2006, we had a limited number of commodity derivatives that were accounted for as cash flow hedges. Gains and losses on these derivatives are offset against corresponding gains or losses of the hedged item and are deferred through other comprehensive income, thus minimizing exposure to cash flow risk. The fair value of the open positions at March 31, 2006, was $0.3 million. Assuming a hypothetical across-the-board 10% price decrease in the applicable forward curve, the change in fair value of the hedging instrument would have been $0.7 million. The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and were estimated based on quoted prices from various sources such as independent reporting services, industry publications, brokers and marketers. The fair values were determined based upon the differences by month between the fixed contract price and the relevant forward price curve, the volumes for the applicable month and a discount rate of 6%.

Interest Rate Risk

We have utilized and expect to continue to utilize interest rate swap agreements to hedge a portion of our cash flow and fair value risks. Interest rate swap agreements are used to manage the fixed and floating interest rate mix of our total debt portfolio and overall cost of borrowing. Interest rate swaps that manage our cash flow risk reduce our exposure to increases in the benchmark interest rates underlying variable rate debt. Interest rate swaps that manage our fair value risks are intended to reduce our exposure to changes in the fair value of the fixed rate debt. Interest rate swap agreements involve the periodic exchange of payments without the exchange of the notional amount upon which the payments are based. The related amount payable to or receivable from counterparties is included as an adjustment to accrued interest.

At March 31, 2006, we had $435.0 million outstanding under our variable interest rate revolving credit facility. The interest rate is based, at our option, on either the lender's base rate plus a spread or LIBOR plus a spread in effect at the time of the borrowings and is adjusted monthly, bimonthly, quarterly or semiannually. In January 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying the credit facility. These interest rate swaps mature in January 2008. We designated these swap agreements as cash flow hedges. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. Because these swaps are designated as cash flow hedges, the changes in fair value, to the extent the swaps are effective, are recognized in other comprehensive income until the hedged interest costs are recognized in earnings. During the three months ended March 31, 2006, we recognized increases in interest expense of $0.1 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. During the three months ended March 31, 2006, we measured the hedge effectiveness of these interest rate swaps and noted that no gain or loss from ineffectiveness was required to be recognized. The total fair value of the interest rate swap agreements was a gain of approximately $1.7 million at March 31, 2006. Utilizing the balances of our variable interest rate debt outstanding at March 31, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense would be $2.4 million.

The following table summarizes the estimated fair values of the Senior Notes as of March 31, 2006 and December 31, 2005 (in millions):

		Fair Value	
	Face Value	March 31, 2006	December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 182.6	$ 183.7
7.625% Senior Notes, due February 2012	500.0	537.9	552.0
6.125% Senior Notes, due February 2013	200.0	200.0	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	223.4	224.1

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and receives a fixed rate of interest of 7.51%. During the three months ended March 31, 2006, and 2005, we recognized reductions in interest expense of $0.7 million and $1.8 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarters ended March 31, 2006 and 2005, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a loss of approximately $7.0 million and $0.9 million at March 31, 2006, and December 31, 2005, respectively. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at March 31, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense would be $2.1 million.

Item 4. Controls and Procedures

As of the end of the period covered by this report, our management carried out an evaluation, with the participation of our principal executive officer (the "CEO") and our principal financial officer (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on those evaluations, as of March 31, 2006, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the first quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a material adverse effect on our consolidated financial position, results of operations or cash flows. See discussion of legal proceedings in Note 13 in the Notes to the Consolidated Financial Statements, which is incorporated into this item by reference.

Item 1A. Risk Factors

Unitholders and potential investors in our Units should carefully consider our risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2005, and below, in addition to other information in such Annual Report and this Report. We are identifying these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by or

on behalf of us. We are relying upon the safe-harbor for forward-looking statements, and any such statements made by or on behalf of us are qualified by reference to the risk factors in our Annual Report on Form 10-K for the year ended December 31, 2005, and the following cautionary statements, as well as to those set forth elsewhere in such Annual Report and this Report.

We depend on the leadership and involvement of our key personnel for the success of our business.

We depend on the leadership and involvement of our key personnel to identify and develop business opportunities and make strategic decisions. Our president and chief executive officer was elected in April 2006, our chief financial officer was elected in January 2006, and our general counsel was elected in March 2006. Our president and chief executive officer has over 35 years of relevant experience and our chief financial officer and general counsel each have approximately 20 years of relevant experience. While retention plans are in place for certain senior executives, any future unplanned departures could have a material adverse effect on our business, financial condition and results of operations. Legacy senior executives have compensation agreements in place; new officers may not be party to any compensation agreements.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated September 21, 2001 (Filed as Exhibit 3.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).

4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Indenture between TE Products Pipeline Company, Limited Partnership and The Bank of New York, as Trustee, dated as of January 27, 1998 (Filed as Exhibit 4.3 to TE Products Pipeline Company, Limited Partnership's Registration Statement on Form S-3 (Commission File No. 333-38473) and incorporated herein by reference).
4.3	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.4	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).

4.6	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
4.7	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.1	Agreement and Release between James C. Ruth and Texas Eastern Products Pipeline Company, LLC dated as of January 25, 2006 (Filed as Exhibit 10.53 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
10.2	Letter of Intent between TEPPCO Partners, L.P. and Enterprise Products Operating, L.P. dated February 13, 2006 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated February 17, 2006 and incorporated herein by reference).
10.3	Waiver of Provisions of the Conflicts Policies and Procedures of the Third Amended and Restated Administrative Services Agreement (Filed as Exhibit 10.56 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith.
** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.

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.

TEPPCO Partners, L.P.

By: /s/ JERRY E. THOMPSON
Jerry E. Thompson,
President and Chief Executive Officer of
Texas Eastern Products Pipeline Company, LLC, General Partner

Date: May 3, 2006

By: /s/ WILLIAM G. MANIAS
William G. Manias,
Vice President and Chief Financial Officer of
Texas Eastern Products Pipeline Company, LLC, General Partner

Date: May 3, 2006

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2002	2003	2004	2005	Three Months Ended March 31, 2006
			(in thousands)		
Earnings					
Income From Continuing Operations *	105,882	104,958	115,347	141,789	41,016
Fixed Charges	73,381	93,294	80,695	93,414	25,464
Distributed Income of Equity Investment	30,938	28,003	47,213	37,085	16,297
Capitalized Interest	(4,345)	(5,290)	(4,227)	(6,759)	(3,259)
Total Earnings	205,856	220,965	239,028	265,529	79,518
Fixed Charges					
Interest Expense	66,192	84,250	72,053	81,861	21,143
Capitalized Interest	4,345	5,290	4,227	6,759	3,259
Rental Interest Factor	2,844	3,754	4,415	4,794	1,062
Total Fixed Charges	73,381	93,294	80,695	93,414	25,464
Ratio: Earnings / Fixed Charges	2.81	2.37	2.96	2.84	3.12

* Excludes discontinued operations, minority interest, extraordinary loss, gain on sale of assets and undistributed equity earnings.

Exhibit 31.1

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended

I, Jerry E. Thompson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TEPPCO Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 3, 2006

/s/ JERRY E. THOMPSON
Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 31.2

**Certification of Chief Financial Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a),
promulgated under the Securities Exchange Act of 1934, as amended**

I, William G. Manias, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TEPPCO Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 3, 2006

/s/ WILLIAM G. MANIAS

William G. Manias
Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of TEPPCO Partners, L.P. (the "Company") on Form 10-Q for the quarter ended March 31, 2006 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JERRY E. THOMPSON

Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

May 3, 2006

A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-Q for the quarter ended March 31, 2006 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ WILLIAM G. MANIAS

William G. Manias
Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

May 3, 2006

A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.