UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 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)

1100 Louisiana Street, Suite 1300
Houston, Texas 77002
(Address of principal executive offices, including zip code)

(713) 381-3636
(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 x 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 x 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 x

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 November 6, 2006: 75,713,554

TEPPCO PARTNERS, L.P.

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Item 1. Financial Statements

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Unaudited)
(in thousands)

	September 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 90	$ 119
Accounts receivable, trade (net of allowance for doubtful accounts of $100 and $250)	789,494	803,373
Accounts receivable, related parties	2,364	5,207
Inventories	26,951	29,069
Other	49,510	61,361
Total current assets	868,409	899,129
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $491,665 and $474,332)	1,607,832	1,960,068
Equity investments	1,016,131	359,656
Intangible assets	189,588	376,908
Goodwill	14,167	16,944
Other assets	71,858	67,833
Total assets	$ 3,767,985	$ 3,680,538
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 824,389	$ 800,033
Accounts payable, related parties	45,620	11,836
Accrued interest	15,969	32,840
Other accrued taxes	17,067	16,532
Other	35,092	75,970
Total current liabilities	938,137	937,211
Senior notes	1,113,075	1,119,121
Other long-term debt	359,000	405,900
Deferred tax liability	657	—
Other liabilities and deferred credits	21,717	16,936
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive (loss) income	(339)	11
General partner's interest	(79,331)	(61,487)
Limited partners' interests	1,415,069	1,262,846
Total partners' capital	1,335,399	1,201,370

Total liabilities and partners' capital	$ 3,767,985	$ 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 September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Operating revenues:				
Sales of petroleum products	$ 2,446,671	$ 2,367,830	$ 7,130,283	$ 5,714,199
Transportation – Refined products	42,067	38,240	113,309	111,039
Transportation – LPGs	16,877	16,519	59,652	63,220
Transportation – Crude oil	9,567	10,001	29,034	28,215
Transportation – NGLs	10,971	11,829	32,362	33,435
Gathering – Natural gas	25,022	38,833	107,856	112,349
Other	18,870	16,875	58,970	48,846
Total operating revenues	2,570,045	2,500,127	7,531,466	6,111,303
Costs and expenses:				
Purchases of petroleum products	2,417,636	2,349,919	7,043,432	5,662,899
Operating expense	49,237	49,079	151,015	135,475
Operating fuel and power	15,478	12,538	42,762	35,154
General and administrative	6,994	8,517	25,353	21,822
Depreciation and amortization	26,250	30,807	83,683	82,556
Taxes – other than income taxes	2,625	5,920	13,984	15,567
Gains on sales of assets	(14)	(31)	(1,410)	(597)
Total costs and expenses	2,518,206	2,456,749	7,358,819	5,952,876
Operating income	51,839	43,378	172,647	158,427
Interest expense – net	(23,181)	(19,726)	(63,522)	(60,640)
Equity earnings	11,567	4,747	15,230	16,592
Other income – net	1,063	484	2,416	885
Income before deferred income tax expense	41,288	28,883	126,771	115,264
Deferred income tax expense	143	—	657	—
Income from continuing operations	41,145	28,883	126,114	115,264
Income from discontinued operations	—	692	1,497	2,662
Gain on sale of discontinued operations	—	—	17,872	—
Discontinued operations	—	692	19,369	2,662
Net income	$ 41,145	$ 29,575	$ 145,483	$ 117,926

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net Income Allocation:				
Limited Partner Unitholders:				
Income from continuing operations	$ 29,047	$ 20,426	$ 89,035	$ 81,527
Income from discontinued operations	—	489	13,674	1,883
Total Limited Partner Unitholders net income allocation	29,047	20,915	102,709	83,410
General Partner:				
Income from continuing operations	12,098	8,457	37,079	33,737
Income from discontinued operations	—	203	5,695	779

Total General Partner net income allocation	12,098	8,660	42,774	34,516
Total net income allocated	$ 41,145	$ 29,575	$ 145,483	$ 117,926
Basic and diluted net income per Limited Partner Unit:				
Continuing operations	$ 0.39	$ 0.29	$ 1.24	$ 1.22
Discontinued operations	—	0.01	0.19	0.03
Basic and diluted net income per Limited Partner Unit	$ 0.39	$ 0.30	$ 1.43	$ 1.25
Weighted average Limited Partner Units outstanding	75,360	69,964	71,782	66,533

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Cash flows from operating activities:		
Net income	$ 145,483	$ 117,926
Adjustments to reconcile net income to cash provided by continuing operating activities:		
Income from discontinued operations	(19,369)	(2,662)
Deferred income tax expense	657	—
Depreciation and amortization	83,683	82,556
Earnings in equity investments	(15,230)	(16,592)
Distributions from equity investments	26,546	28,178
Gains on sales of assets	(1,410)	(597)
Non-cash portion of interest expense	1,241	1,214
Increase in accounts receivable, trade	(3,995)	(296,340)
Decrease in accounts receivable, related parties	1,309	6,523
Decrease (increase) in inventories	103	(111,083)
Decrease (increase) in other current assets	5,877	(21,002)
Increase in accounts payable and accrued expenses	2,159	283,167
Increase (decrease) in accounts payable, related parties	14,919	(14,796)
Other	(10,960)	(10,530)
Net cash provided by continuing operating activities	231,013	45,962
Net cash provided by discontinued operations	1,521	3,110
Net cash provided by operating activities	232,534	49,072
Cash flows from investing activities:		
Proceeds from the sales of assets	39,750	510
Purchase of assets	(10,975)	(112,231)
Investment in Centennial Pipeline LLC	(2,500)	—
Investment in Mont Belvieu Storage Partners, L.P.	(4,168)	(2,635)
Investment in Jonah Gas Gathering Company	(65,342)	—
Cash paid for linefill on assets owned	(5,640)	(5,124)
Capital expenditures	(125,684)	(148,063)
Net cash used in investing activities	(174,559)	(267,543)
Cash flows from financing activities:		
Proceeds from revolving credit facility	509,750	549,657
Repayments on revolving credit facility	(556,650)	(442,157)
Issuance of Limited Partner Units, net	195,072	278,830
Distributions paid	(206,176)	(184,209)
Net cash provided by (used in) financing activities	(58,004)	202,121
Net decrease in cash and cash equivalents	(29)	(16,350)
Cash and cash equivalents at beginning of period	119	16,422
Cash and cash equivalents at end of period	$ 90	$ 72

	Nine Months Ended September 30, 2006	2005
Non-cash investing activities:		
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ —	$ 1,429
Net assets transferred to Jonah Gas Gathering Company	$ 572,609	$ —
Payable to Enterprise Gas Processing, LLC for spending for Phase V expansion of Jonah Gas Gathering Company	$ 18,943	$ —
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ 84,402	$ 78,504

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 (Loss)	Total
Partners' capital at December 31, 2005	69,963,554	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370
Issuance of Limited Partner Units, net	5,750,000	—	195,072	—	195,072
Net income allocation	—	42,774	102,709	—	145,483
Cash distributions	—	(60,618)	(145,558)	—	(206,176)
Changes in fair values of interest rate cash flow hedges	—	—	—	(584)	(584)
Changes in fair values of crude oil cash flow hedges	—	—	—	234	234
Partners' capital at September 30, 2006	75,713,554	$ (79,331)	$ 1,415,069	$ (339)	$ 1,335,399

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Net income	$ 41,145	$ 29,575	$ 145,483	$ 117,926
Changes in fair values of interest rate cash flow hedges	(584)	—	(584)	—
Changes in fair values of crude oil cash flow hedges	507	35	234	35
Comprehensive income	$ 41,068	$ 29,610	$ 145,133	$ 117,961

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. Mr. Duncan and his affiliates, including EPCO and Dan Duncan LLC, privately held companies controlled by him, control us, the General Partner and Enterprise Products Partners L.P. ("Enterprise"). 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 ("ASA"), 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 September 30, 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 September 30, 2006, and the results of our operations and cash flows for the periods presented. The results of operations for the three months and nine months ended September 30, 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 our Current Report on Form 8-K filed on June 16, 2006, which recast certain information from our Annual Report on Form 10-K for the year ended December 31, 2005, as discontinued operations. We have reclassified certain amounts from prior periods to conform to the current presentation. Effective August 1, 2006, we have deconsolidated Jonah Gas Gathering Company ("Jonah") due to the formation of a joint venture with an affiliate of Enterprise. Jonah has been subsequently accounted for as an equity method investment (see Note 8).

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 75.4 million Units and 70.0 million Units for the three months ended September 30, 2006 and 2005, respectively, and a total of 71.8 million Units and 66.5 million Units for the nine months ended September 30, 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 10). The General Partner was allocated $12.1 million (representing 29.4%) and $8.7 million (representing 29.27%) of our net income for the three months ended September 30, 2006 and 2005, respectively, and $42.8 million (representing 29.4%) and $34.5 million (representing 29.27%) of our net income for the nine months ended September 30, 2006 and 2005, respectively. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with the Partnership Agreement.

Diluted net income per Unit equaled basic net income per Unit for each of the three-month and nine-month periods ended September 30, 2006 and 2005, as there were no dilutive instruments outstanding.

Deferred Income Tax Expense – Texas Margin Tax

In May 2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaces its existing franchise tax. In general, legal entities that do business in Texas are subject to the Texas Margin Tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the state of Texas changed from nontaxable to taxable. The Texas Margin Tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Our deferred income tax expense for state taxes relates only to Texas Margin Tax obligations. The Texas Margin Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenues less (a) cost of goods sold or (b) compensation. The deferred tax liability shown on our consolidated balance sheet reflects the net tax effect of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is classified as noncurrent. The Texas Margin Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of at least 80% is

owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together. We have calculated and recorded an estimated deferred tax liability of approximately $0.7 million associated with the Texas Margin Tax. The non-cash offsetting charge is shown on our unaudited consolidated statements of income as deferred income tax expense for the nine months ended September 30, 2006.

Since the Texas Margin Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, we determined the Texas Margin Tax should be accounted for as an income tax in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*.

Asset Retirement Obligations

During the second and third quarters of 2006, we recorded $0.3 million and $0.3 million of expense, respectively, included in depreciation and amortization expense, related to conditional asset retirement obligations. Additionally, we have recorded a $1.2 million liability, which represents the fair values of conditional asset retirement obligations related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination and related to the retirement of certain of our natural gas gathering systems. These conditional asset retirement obligations were not previously recorded, due to the indeterminate range of settlement dates and settlement methods, during the implementation of SFAS No. 143, *Accounting for Asset Retirement Obligations*, and Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*, which we adopted on January 1, 2003 and December 31, 2005, respectively. During the second and third quarters of 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded asset retirement obligations.

New Accounting Pronouncements

In December 2004, the FASB issued 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 ("SEC") decided to delay the effective date for public companies to implement SFAS 123(R). SFAS 123(R) became 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. We have determined that our 1999 and 2005 Phantom Unit Plans 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 adopted EITF 04-13 on April 1, 2006, which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. The treatment of buy/sell transactions under EITF 04-13 reduced the relative amount of revenues and purchases of petroleum products on our consolidated statement of income by approximately $774.4 million each for the period from April 1, 2006 through September 30, 2006 ($460.7 million for the three months ended September 30, 2006). The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our consolidated statements of income for the three months and nine months ended September 30, 2005, and for the period from January 1, 2006 through March 31, 2006, are approximately $494.7 million, $898.0 million and $275.4 million, respectively.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. SFAS 155 improves the financial reporting of certain hybrid financial instruments and simplifies the accounting for these instruments. SFAS 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to the requirements of SFAS 133, establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an

embedded derivative requiring bifurcation, clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives, and amends SFAS 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement event occurring after the fiscal year that begins after September 15, 2006 (January 1, 2007). At September 30, 2006, we did not have any hybrid financial securities outstanding and, as such, we do not believe that adoption of SFAS 155 will have a material effect on our financial position, results of operations or cash flows, unless such hybrid securities are issued by us prior to SFAS 155 becoming effective.

In June 2006, the EITF reached consensus in EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The accounting guidance permits companies to elect to present on either a gross or net basis sales and other taxes that are imposed on and concurrent with individual revenue-producing transactions between a seller and a customer. The gross basis includes the taxes in revenues and costs; the net basis excludes the taxes from revenues. The accounting guidance does not apply to tax systems that are based on gross receipts or total revenues. EITF 06-3 requires companies to disclose their policy for presenting the taxes and disclose any amounts presented on a gross basis if those amounts are significant. The guidance in EITF 06-3 is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis. We believe that adoption of EITF 06-3 will not have a material effect on our financial position, results of operations or cash flows.

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an Interpretation of SFAS 109, *Accounting for Income Taxes* ("FIN 48"). FIN 48 provides that the tax effects of an uncertain tax position should be recognized in a company's financial statements if the position taken by the entity is more likely than not sustainable if it were to be examined by an appropriate taxing authority, based on technical merit. After determining if a tax position meets such criteria, the amount of benefit to be recognized should be the largest amount of benefit that has more than a 50% chance of being realized upon settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, and we are required to adopt FIN 48 as of January 1, 2007. We are currently assessing the impact, if any, that the adoption of FIN 48 will have on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period. SFAS 157 is effective for fiscal years beginning after December 15, 2007, and we are required to adopt SFAS 157 as of January 1, 2008. We are currently assessing the impact that the adoption of SFAS 157 will have on our financial position, results of operations and cash flows.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 addresses how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in current-year financial statements. The SAB requires registrants to quantify misstatements using both balance-sheet and income-statement approaches and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is determined to be material, SAB 108 allows registrants to record that effect as a cumulative-effect adjustment to

beginning-of-year retained earnings. The requirements are effective for annual financial statements covering the first fiscal year ending after November 15, 2006. Additionally, the nature and amount of each individual error being corrected through the cumulative-effect adjustment, when and how each error arose, and the fact that the errors had previously been considered immaterial is required to be disclosed. We are required to adopt SAB 108 for our current fiscal year ending December 31, 2006. We do not expect the adoption of SAB 108 to 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 September 30, 2006 and December 31, 2005, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill:				
September 30, 2006 (1)	$ —	$ —	$ 14,167	$ 14,167
December 31, 2005	—	2,777	14,167	16,944

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 8).

Other Intangible Assets

The following table reflects the components of intangible assets, including excess investments, being amortized at September 30, 2006, and December 31, 2005 (in thousands):

	September 30, 2006		December 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements (1)	$ 241,537	$ (81,683)	$ 464,337	$ (118,921)
Fractionation agreement	38,000	(16,150)	38,000	(14,725)
Other	10,336	(2,452)	10,226	(2,009)
Subtotal	289,873	(100,285)	512,563	(135,655)
Excess investments:				
Centennial Pipeline LLC	33,390	(15,678)	33,390	(12,947)
Seaway Crude Pipeline Company	27,100	(4,282)	27,100	(3,764)
Subtotal	60,490	(19,960)	60,490	(16,711)
Total intangible assets	$ 350,363	$ (120,245)	$ 573,053	$ (152,366)

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 8).

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 $6.7 million and $8.2 million for the three months ended September 30, 2006 and 2005, respectively, and $22.7 million and $22.3 million for the nine months ended September 30, 2006 and 2005, respectively. Amortization expense on excess investments included in equity earnings was $1.2 million and $1.3 million for the three months ended September 30, 2006 and 2005, respectively, and $3.2 million and $3.8 million for the nine months ended September 30, 2006 and 2005, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on Val Verde Gas Gathering Company, L.P.'s 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 system, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. During the quarter ended September 30, 2006, we received updated limited production estimates from some of the producers on the Val Verde system, which reduced the future production forecast. We revised the units-of-production calculation for Val Verde, which increased amortization expense by approximately $0.2 million per month. Further 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 (1)	Excess Investments
2006	$ 28,916	$ 4,691
2007	22,707	5,113
2008	19,965	5,438
2009	17,485	6,878
2010	15,509	7,042

(1) Excludes estimated amortization expense of Jonah's intangible assets as a result of its deconsolidation effective August 1, 2006.

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 nine months ended September 30, 2006 and 2005, we recognized reductions in interest expense of $1.5 million and $4.6 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 September 30, 2006 and 2005, we reviewed the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair values of this interest rate swap were losses of approximately $3.9 million and $0.9 million at September 30, 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 September 30, 2006, the unamortized balance of the deferred gains was $29.1 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.

During May 2005, we executed a treasury rate lock agreement for a notional amount of $200.0 million to hedge our exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for a debt offering that was proposed to occur in the second quarter of 2005. During June 2005, the proposed debt offering was cancelled, and the treasury lock was terminated with a realized loss of $2.0 million. The realized loss was recorded as a component of interest expense in the consolidated statements of income in June 2005.

On January 20, 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. 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. In the third quarter of 2006, these swaps were designated as cash flow hedges. For the period from January 20, 2006 through the date these swaps were designated as cash flow hedges, changes in the fair value of the swaps were recognized in earnings, which resulted in a $2.2 million reduction to interest expense. While these interest rate swaps remain in effect, future changes in the fair value of the cash flow hedges, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings. At September 30, 2006, the fair value of these interest rate swaps was $1.5 million.

NOTE 4. PROPERTY, PLANT AND EQUIPMENT

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

During the third quarter of 2005, our Upstream Segment was notified by a connecting carrier that the flow of the carrier's pipeline system would be reversed, which would directly impact the viability of one of our pipeline systems. This system, located in East Texas, consists of approximately 45 miles of pipeline, six tanks of various sizes and other equipment and asset costs. As a result of changes to the connecting carrier, we performed an impairment test of the system and recorded a $1.8 million non-cash impairment charge, or $0.03 per Unit, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the fair value of the system.

During the third quarter of 2005, we completed an evaluation of a crude oil system included in our Upstream Segment. The system, located in Oklahoma, consists of approximately six miles of pipelines, tanks and other equipment and asset costs. The usage of the system has declined in recent months as a result of shifting crude oil production into areas not supported by the system, and as such, it has become more economical to transport barrels by truck to our other pipeline systems. As a result, we performed an impairment test on the system and recorded a $0.8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the fair value of the system.

In September 2005, our Todhunter facility, near Middletown, Ohio, experienced a propane release and fire at a dehydration unit within the storage facility. The facility is included in our Downstream Segment. The dehydration unit was destroyed due to the propane release and fire, and as a result, we wrote off the remaining book value of the asset of $0.8 million to depreciation and amortization expense during the third quarter of 2005.

NOTE 5. 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.

Storage and Terminaling Assets

On April 1, 2005, we purchased crude oil storage and terminaling assets in Cushing, Oklahoma, from Koch Supply & Trading, L.P. for $35.4 million. The assets consist of eight storage tanks with 945,000 barrels of storage capacity, receipt and delivery manifolds, interconnections to several pipelines, crude oil inventory and approximately 70 acres of land. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment and inventory.

Refined Products Terminal and Truck Rack

On July 12, 2005, we purchased a refined products terminal and two-bay truck loading rack in North Little Rock, Arkansas, for $6.8 million from Exxon Mobil Corporation. The assets include three storage tanks and a two-bay truck loading rack. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment and inventory. The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas.

Genco Assets

On July 15, 2005, we acquired from Texas Genco LLC ("Genco") all of its interests in certain companies that own a 90-mile pipeline system and 5.5 million barrels of storage capacity for $62.1 million. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. This acquisition was made as part of an expansion of our refined products origin capabilities in the Houston, Texas, and Texas City, Texas, areas. The assets of the purchased companies are being integrated into our Downstream Segment origin infrastructure in Texas City and Baytown, Texas. The integration and other system enhancements should be in service by the first quarter of 2007, at an estimated cost of $45.0 million. See Note 17 regarding the sale of certain of these assets to Enterprise.

Terminal Assets

On July 14, 2006, we purchased assets from New York LP Gas Storage, Inc. for $10.0 million. The assets consist of two active caverns, one active brine pond, a four bay truck rack, seven above ground storage tanks, and a twelve-spot railcar rack located east of our Watkins Glen, New York facility. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and inventory.

NOTE 6. 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 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 recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner and a fairness opinion was rendered by an independent third-party. The sales proceeds were 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 were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months and nine months ended September 30, 2006 and 2005, are presented below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Sales of petroleum products	$ —	$ 2,880	$ 3,828	$ 7,337
Other	—	789	932	2,141
Total operating revenues	—	3,669	4,760	9,478
Purchases of petroleum products	—	2,585	3,000	5,761
Operating expense	—	205	182	501
Depreciation and amortization	—	153	51	459
Taxes – other than income taxes	—	34	30	95
Total costs and expenses	—	2,977	3,263	6,816
Income from discontinued operations	$ —	$ 692	$ 1,497	$ 2,662

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

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

Cash flows from discontinued operations for the nine months ended September 30, 2006 and 2005, are presented below (in thousands):

	Nine Months Ended September 30,	
	2006	2005
Cash flows from operating activities:		
Net income	$ 19,369	$ 2,662
Depreciation and amortization	51	459
Gain on sale of Pioneer plant	(17,872)	—
Increase in inventories	(27)	(11)
Cash flow from discontinued operations	$ 1,521	3,110

NOTE 7. 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 September 30, 2006, and December 31, 2005. The major components of inventories were as follows (in thousands):

	September 30, 2006	December 31, 2005
Crude oil (1)	$ 3,754	$ 3,021
Refined products and LPGs (2)	8,361	11,864
Lubrication oils and specialty chemicals	7,281	5,740
Materials and supplies	7,423	8,203
Other	132	241
Total	$ 26,951	$ 29,069

(1) At September 30, 2006, substantially all of our crude oil inventory was subject to forward sales contracts.

(2) Refined products and LPGs inventory is managed on a combined basis.

NOTE 8. EQUITY INVESTMENTS

Seaway

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 nine months ended September 30, 2006 and 2005, we received distributions from Seaway of $15.3 million and

$17.5 million, respectively. During the nine months ended September 30, 2006 and 2005, we did not invest any funds in Seaway.

Centennial

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 nine months ended September 30, 2006, TE Products contributed $2.5 million to Centennial. During the nine months ended September 30, 2005, TE Products did not invest any funds in Centennial. TE Products has received no cash distributions from Centennial since its formation.

MB Storage

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. See Note 14 regarding the expected divestiture of 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 nine months ended September 30, 2006 and 2005, TE Products' sharing ratios in the earnings of MB Storage were approximately 63.8% and 64.3%, respectively. During the nine months ended September 30, 2006, TE Products received distributions from MB Storage of $11.2 million and contributed $4.2 million to MB Storage. During the nine months ended September 30, 2005, TE Products received distributions of $10.7 million from MB Storage and contributed $4.0 million to MB Storage, which included a combination of non-cash asset transfers of $1.4 million and cash contributions of $2.6 million.

Summarized Financial Information for Seaway, Centennial and 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 nine months ended September 30, 2006 and 2005, is presented below (in thousands):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Revenues	$ 122,742	$ 123,224
Net income	26,030	39,896

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of September 30, 2006, and December 31, 2005, is presented below (in thousands):

	September 30, 2006	December 31, 2005
Current assets	$ 62,269	$ 60,082
Noncurrent assets	619,904	630,212
Current liabilities	24,502	32,242
Long-term debt	150,000	150,000
Noncurrent liabilities	21,341	13,626
Partners' capital	486,330	494,426

Jonah

On August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the partnership through which we owned the Jonah system. Prior to entering into the Jonah joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet ("Bcf") per day to approximately 2.4 Bcf per day and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf per day, is scheduled to be completed in the first quarter of 2007 at an estimated cost of approximately $295.0 million. The second portion of the expansion is expected to cost approximately $170.0 million and be completed by the end of 2007. We expect to reimburse Enterprise for approximately 50% of these costs.

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point Enterprise will be entitled to receive approximately 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. In the third quarter of 2006, we reimbursed Enterprise $65.0 million for 50% of the Phase V cost incurred by it through August 1, 2006 (including its cost of capital of $1.3 million). At September 30, 2006, we had a payable to Enterprise for costs incurred through September 30, 2006, of $18.9 million. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, we expect to own an interest in Jonah of approximately 80%, with Enterprise owning the remaining 20% and serving as operator, with further costs being allocated based on such ownership interests. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner.

Effective August 1, 2006, with the formation of the joint venture, Jonah was deconsolidated, and we began using the equity method of accounting to account for our investment in Jonah. Under the equity method, we record the costs of our investment within the "Equity Investments" line on our consolidated balance sheet, and as changes in the net assets of Jonah occur (for example, earnings, contributions and distributions), we will recognize our proportional share of that change in the "Equity Investments" account.

Summarized financial information for Jonah for the period August 1, 2006 through September 30, 2006, is presented below (in thousands):

Revenues	$	30,101
Net income		11,563

Summarized balance sheet information for Jonah as of September 30, 2006, is presented below (in thousands):

Current assets	$	39,202
Noncurrent assets		725,953
Current liabilities		15,425
Noncurrent liabilities		186
Partners' capital		749,544

NOTE 9. 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 September 30, 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 September 30, 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 September 30, 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 September 30, 2006, and December 31, 2005 (in millions):

	Face Value	Fair Value: September 30, 2006	Fair Value: December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 182.2	$ 183.7
7.625% Senior Notes, due February 2012	500.0	536.1	552.0
6.125% Senior Notes, due February 2013	200.0	200.7	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	222.6	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

We have in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matures on December 13, 2011. 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 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 10), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets.

On July 31, 2006, we amended our Revolving Credit Facility. The primary revisions were as follows:

- The maturity date of the credit facility was extended from December 13, 2010 to December 13, 2011. 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 releases Jonah as a guarantor of the Revolving Credit Facility and restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other third-party debt in the principal aggregate amount of $50.0 million.
- The amendment modifies the financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility) pro forma adjustments for material capital projects.
- The amendment allows for the issuance of Hybrid Securities (as defined in the Revolving Credit Facility) of up to 15% of our Consolidated Total Capitalization (as defined in the Revolving Credit Facility).

At September 30, 2006, $359.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 6.02%. At September 30, 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 September 30, 2006, and December 31, 2005 (in thousands):

	September 30, 2006	December 31, 2005
Revolving Credit Facility, due December 2011	$ 359,000	$ 405,900
6.45% TE Products Senior Notes, due January 2008	179,960	179,937
7.625% Senior Notes, due February 2012	498,825	498,659
6.125% Senior Notes, due February 2013	199,095	198,988
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,446,880	1,493,484
Adjustment to carrying value associated with hedges of fair value	25,195	31,537

Total Debt Instruments	$ 1,472,075	$ 1,525,021

Letter of Credit

At September 30, 2006, we had outstanding a $10.1 million standby letter of credit in connection with crude oil purchased during the third quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the fourth quarter of 2006.

NOTE 10. PARTNERS' CAPITAL AND DISTRIBUTIONS

Equity Offering

In July 2006, we issued and sold in an underwritten public offering 5.0 million Units at a price to the public of $35.50 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $170.4

million. On July 12, 2006, 750,000 additional Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. Proceeds from the over-allotment sale, net of underwriting discount, totaled $25.6 million. The net proceeds from the offering and the over-allotment were used to reduce indebtedness under our Revolving Credit Facility.

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 (1)	50%	50%

(1) See "– EPCO Proposal" below for a discussion of the proposed elimination of the 50%/50% distribution tier in exchange for the issuance of additional Units to the General Partner.

The following table reflects the allocation of total distributions paid during the nine months ended September 30, 2006 and 2005 (in thousands, except per Unit amounts):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Limited Partner Units	$ 145,558	$ 130,694
General Partner Ownership Interest	2,971	2,667
General Partner Incentive	57,647	50,848
Total Cash Distributions Paid	$ 206,176	$ 184,209
Total Cash Distributions Paid Per Unit	$ 2.025	$ 2.00

On November 7, 2006, we paid a cash distribution of $0.675 per Unit for the quarter ended September 30, 2006. The third quarter 2006 cash distribution totaled $72.4 million.

General Partner's Interest

As of September 30, 2006, and December 31, 2005, we had deficit balances of $79.3 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 nine months ended September 30, 2006, the General Partner was allocated $42.8 million (representing 29.4%) of our net income and received $60.6 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 September 30, 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 as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion. Cash distributions in excess of net income allocations and capital contributions during the year ended December 31, 2005, and the nine months ended September 30, 2006, resulted in deficits in the General Partner's equity account at December 31, 2005, and September 30, 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 our 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.

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 reduce the General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to reduce its maximum percentage interest in our quarterly distributions, our General Partner would receive a number of newly-issued Units that, based on the distribution rate and the number of Units outstanding at the time of issuance, would result in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions that would approximately equal the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without reduction. Based on our distribution rate and outstanding Units as of the date of the filing of this Report, the number of newly-issued Units issued to the General Partner would be approximately 14.1 million. On September 11, 2006, we filed with the Securities and Exchange Commission a definitive proxy statement that outlines the EPCO proposal to be voted upon at a special meeting of our unitholders and other changes to our Partnership Agreement that are part of the EPCO proposal, all of which are conditioned upon one another. The proxy statement also contains separate proposals for the adoption of an employee Unit purchase plan and a long term incentive plan. The special meeting was convened on October 26, 2006, and adjourned, without voting on the proposals, to November 30, 2006 by the General Partner for lack of a quorum.

NOTE 11. 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 the ASA. 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 and nine months ended September 30, 2006 and 2005 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenues from EPCO and affiliates: (1)				
Sales of petroleum products	$ 1.0	$ —	$ 3.1	$ —
Transportation – NGLs	2.8	2.3	7.4	5.2
Transportation – LPGs	0.5	1.1	2.8	2.7
Other operating revenues	0.4	—	0.6	—
Costs and Expenses from EPCO and affiliates: (1)				
Payroll, administrative and other (2)	27.9	29.1	90.2	37.9
Purchases of petroleum products	14.0	—	30.5	—
Revenues from DEFS and affiliates: (3)				
Sales of petroleum products	—	—	—	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: (3)				
Payroll, administrative and other (4) (5)	—	—	—	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, as a result of the change in ownership of the General Partner.

(2) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred in managing us and our subsidiaries in accordance with the ASA.

(3) 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.

(4) 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 contractual agreements established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we or EPCO have assumed these activities.

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

At September 30, 2006 and December 31, 2005, we had receivables from EPCO and affiliates of $1.6 million and $4.3 million, respectively, related to sales and transportation services provided to EPCO and affiliates. At September 30, 2006 and December 31, 2005, we had payables to EPCO and affiliates of $41.6 million and $9.8 million, respectively, related to direct payroll, payroll related costs and other operational related costs attributable to our operations under the ASA.

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. We incurred insurance expense related to premiums paid by EPCO of $3.6 million and $2.4 million for the three months ended September 30, 2006 and 2005, respectively. We incurred insurance expense related to premiums paid by EPCO of $10.8 million (including $0.1 million in finance charges) and $4.5 million for the nine months ended September 30, 2006 and 2005, respectively. At September 30, 2006 and December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.8 million and $1.3 million, respectively.

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 6).

On October 6, 2006, we sold certain idled crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, with a carrying value of approximately $5.6 million, to an affiliate of Enterprise for approximately $11.7 million (see Note 17). We also anticipate selling additional refined products pipeline assets in the Houston, Texas area to an affiliate of Enterprise in the fourth quarter of 2006 for approximately $8.0 million, which at September 30, 2006, have a carrying value of approximately $2.5 million. These transactions were reviewed and recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner.

Jonah Joint Venture

On August 1, 2006, Enterprise (through an affiliate) became our joint venture partner by acquiring an interest in Jonah, the partnership through which we owned the Jonah system. In the third quarter of 2006, we reimbursed Enterprise $65.0 million for 50% of the Phase V cost incurred by it through August 1, 2006 (including its cost of capital of $1.3 million). At September 30, 2006, we had a payable to Enterprise for costs incurred through September 30, 2006, of $18.9 million (see Note 8 for further discussion on the Jonah joint venture).

In conjunction with the formation of the joint venture, we have agreed to indemnify Enterprise from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the formation of the Jonah joint venture, Jonah's ownership or operation of the Jonah system prior to the effective date of the joint venture, and any environmental activity, or violation of or liability under environmental laws arising from or related to the condition of the Jonah system prior to the effective date of the joint venture. In general, a claim for indemnification cannot be filed until the losses suffered by Enterprise exceed $1.0 million, and the maximum potential amount of future payments under the indemnity is limited to $100.0 million. However, if certain representations or warranties are breached, the maximum potential amount of future payments under the indemnity is capped at $207.6 million. All indemnity payments are net of insurance recoveries that Enterprise may receive from third-party insurers. We carry insurance coverage that may

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offset any payments required under the indemnity. We do not expect that these indemnities will have a material adverse effect on our financial position, results of operations or cash flows.

NOTE 12. 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 June 1, 2005, EPCO adopted the TEPPCO RCBP and the TEPPCO SBP for the benefit of its employees providing services to us. 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 during the fourth quarter of 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 and nine months ended September 30, 2006 and 2005, were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	$ —	$ 1,147	$ —	$ 3,246
Interest cost on projected benefit obligation	255	233	762	701
Expected return on plan assets	(115)	(76)	(351)	(595)
Amortization of prior service cost	—	1	—	4
Amortization of actuarial losses	35	37	104	92
SFAS 88 curtailment charge	—	—	—	50
Net pension benefits costs	$ 175	$ 1,342	$ 515	$ 3,498

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 and nine months ended September 30, 2006 and 2005, were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	$ —	$ —	$ —	$ 81
Interest cost on accumulated postretirement benefit obligation	—	—	—	69
Amortization of prior service cost	—	—	—	53
Recognized net actuarial loss	—	—	—	4
SFAS 106 curtailment credit	—	—	—	(1,676)
Net postretirement benefits costs	$ —	$ —	$ —	$ (1,469)

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. However, EPCO maintains a 401(k) plan for the benefit of employees providing services to us, and we will continue to reimburse EPCO for the cost of maintaining this plan in accordance with the ASA.

NOTE 13. 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 in this segment during the first and fourth quarters of each year since these 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 MB Storage, which we are required to divest (see Note 14), and in Centennial (see Note 8).

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 8). 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 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. Our Midstream Segment also includes our equity investment in Jonah (see Note 8). Jonah, which is a joint venture between us and an affiliate of Enterprise, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise’s affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which we sold to an Enterprise affiliate in March 2006, are shown as discontinued operations for the three months and nine months ended September 30, 2006 and 2005.

On April 1, 2006, we adopted EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (see Note 1), which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our consolidated statements of income by approximately $774.4 million each for the period from April 1, 2006 through September 30, 2006 ($460.7 million for the three months ended September 30, 2006). Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our consolidated statements of income for the three months and nine months ended September 30, 2005, and for the period from January 1, 2006 through March 31, 2006, are approximately $494.7 million, $898.0 million and $275.4 million, respectively.

The table below includes financial information by reporting segment for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 2,441,750	$ 4,990	$ 2,446,740	$ (69)	$ 2,446,671
Operating revenues	72,358	12,176	38,905	123,439	(65)	123,374
Purchases of petroleum products	—	2,413,391	4,323	2,417,714	(78)	2,417,636
Operating expenses, including power and taxes – other than income taxes	38,618	15,930	12,857	67,405	(65)	67,340
General and administrative expenses	3,455	1,460	2,079	6,994	—	6,994
Depreciation and amortization expense	10,713	3,699	11,838	26,250	—	26,250
Gains on sales of assets	(14)	—	—	(14)	—	(14)
Operating income	19,586	19,446	12,798	51,830	9	51,839
Equity earnings (losses)	(2,949)	2,962	11,563	11,576	(9)	11,567
Other income, net	289	344	430	1,063	—	1,063
Earnings before interest, deferred income tax expense and discontinued operations	$ 16,926	$ 22,752	$ 24,791	$ 64,469	$ —	$ 64,469

	Three Months Ended September 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 2,367,984	$ —	$ 2,367,984	$ (154)	$ 2,367,830
Operating revenues	66,094	12,750	53,641	132,485	(188)	132,297
Purchases of petroleum products	—	2,350,107	—	2,350,107	(188)	2,349,919
Operating expenses, including power and taxes – other than income taxes	36,788	17,200	13,703	67,691	(154)	67,537
General and administrative expenses	4,617	1,756	2,144	8,517	—	8,517
Depreciation and amortization expense	10,098	6,471	14,238	30,807	—	30,807
Gains on sales of assets	(24)	(7)	—	(31)	—	(31)
Operating income	14,615	5,207	23,556	43,378	—	43,378
Equity earnings (losses)	(651)	5,398	—	4,747	—	4,747
Other income, net	306	103	75	484	—	484
Earnings before interest, deferred income tax expense and discontinued operations	$ 14,270	$ 10,708	$ 23,631	$ 48,609	$ —	$ 48,609

	Nine Months Ended September 30, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 7,116,064	$ 18,766	$ 7,134,830	$ (4,547)	$ 7,130,283
Operating revenues	215,758	36,456	151,851	404,065	(2,882)	401,183
Purchases of petroleum products	—	7,032,930	17,272	7,050,202	(6,770)	7,043,432
Operating expenses, including power and taxes – other than income taxes	111,763	50,892	45,774	208,429	(668)	207,761
General and administrative expenses	13,250	5,137	6,966	25,353	—	25,353
Depreciation and amortization expense	31,143	10,464	42,076	83,683	—	83,683
Gains on sales of assets	(39)	—	(1,371)	(1,410)	—	(1,410)
Operating income	59,641	53,097	59,900	172,638	9	172,647
Equity earnings (losses)	(6,581)	10,257	11,563	15,239	(9)	15,230
Other income, net	1,253	613	550	2,416	—	2,416
Earnings before interest, deferred income tax expense and discontinued operations	$ 54,313	$ 63,967	$ 72,013	$ 190,293	$ —	$ 190,293

	Nine Months Ended September 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 5,714,353	$ —	$ 5,714,353	$ (154)	$ 5,714,199
Operating revenues	207,699	36,161	155,481	399,341	(2,237)	397,104
Purchases of petroleum products	—	5,665,136	—	5,665,136	(2,237)	5,662,899
Operating expenses, including power and taxes – other than income taxes	104,943	45,132	36,275	186,350	(154)	186,196
General and administrative expenses	12,328	4,483	5,011	21,822	—	21,822
Depreciation and amortization expense	29,460	13,623	39,473	82,556	—	82,556
Gains on sales of assets	(131)	(59)	(407)	(597)	—	(597)

Operating income	61,099	22,199	75,129	158,427	—	158,427
Equity earnings (losses)	(2,718)	19,310	—	16,592	—	16,592
Other income, net	576	132	177	885	—	885
Earnings before interest, deferred income tax expense and discontinued operations	$ 58,957	$ 41,641	$ 75,306	$ 175,904	$ —	$ 175,904

The following table includes total assets, capital expenditures, and significant non-cash investing activities for each segment as of and for the periods ended September 30, 2006, and December 31, 2005 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
September 30, 2006:						
Total assets	$ 1,081,693	$ 1,385,414	$ 1,305,690	$ 3,772,797	$ (4,812)	$ 3,767,985
Capital expenditures	47,053	35,028	41,624	123,705	1,979	125,684
Non-cash investing activities	—	—	591,552	591,552	—	591,552
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 segment data from the tables above to consolidated net income for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Earnings before interest, deferred income tax expense and discontinued operations	$ 64,469	$ 48,609	$ 190,293	$ 175,904
Interest expense – net	(23,181)	(19,726)	(63,522)	(60,640)
Income before deferred income tax expense	41,288	28,883	126,771	115,264
Deferred income tax expense	143	—	657	—
Income from continuing operations	41,145	28,883	126,114	115,264
Discontinued operations	—	692	19,369	2,662
Net income	$ 41,145	$ 29,575	$ 145,483	$ 117,926

NOTE 14. COMMITMENTS AND CONTINGENCIES

Litigation

In the fall of 1999, the General Partner and TE Products were named as defendants in a lawsuit in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. and Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al.* In the lawsuit, 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 complaint, 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 March 18, 2005, we entered into Release and Settlement Agreements with the McCleery 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 *Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed, by Cooperative Defense

Agreement, to fund the defense and satisfy all final judgments which might be rendered with the 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 assert damages attributable to the remediation of the property of approximately $1.4 million; 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 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 codefendants. 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.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of our other unitholders, and derivatively on our behalf, concerning proposals made to our unitholders in our definitive proxy statement filed with the SEC on September 11, 2006 ("Proxy Statement") and other transactions involving us and Enterprise or its affiliates. The complaint names as defendants the General Partner; the Board of Directors of the General Partner; the parent companies of the General Partner, including EPCO; Enterprise and certain of its affiliates; and Dan L. Duncan. We are named as a nominal defendant.

The complaint alleges, among other things, that certain of the transactions proposed in the Proxy Statement, including a proposal to reduce the General Partner's maximum percentage interest in our distributions in exchange for Units (the "Issuance Proposal"), are unfair to our unitholders and constitute a breach by the defendants of fiduciary duties owed to our unitholders and that the Proxy Statement fails to provide our unitholders with all material facts necessary for them to make an informed decision whether to vote in favor of or against the proposals. The complaint further alleges that, since Mr. Duncan acquired control of the General Partner in 2005, the defendants, in breach of their fiduciary duties to us and our unitholders, have caused us to enter into certain transactions with Enterprise or its affiliates that are unfair to us or otherwise unfairly favored Enterprise or its affiliates over us. These transactions are alleged to include the Jonah joint venture entered into by us and an Enterprise affiliate in August 2006, the sale by us to an Enterprise affiliate of the Pioneer plant in March 2006 and the impending divestiture of our interest in MB Storage in connection with an investigation by the Federal Trade Commission ("FTC"). As more fully described in the Proxy Statement, the Audit and Conflicts Committee of the Board of Directors of the General Partner recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the Audit and Conflicts Committee, cannot be considered independent because of their alleged ownership of securities in Enterprise and its affiliates and their relationships with Mr. Duncan.

The complaint seeks relief (i) requiring us to issue a proxy statement that corrects the alleged misstatements and omissions in the Proxy Statement; (ii) enjoining the October 26, 2006 meeting of unitholders provided for in the Proxy Statement; (iii) rescinding transactions in the complaint that have been consummated or awarding rescissory damages in respect thereof; (iv) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; and (v) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

On September 22, 2006, the plaintiff in the action filed a motion to expedite the proceedings, requesting the Court to schedule a hearing on plaintiff's motion for a preliminary injunction to enjoin the defendants from proceeding with the October 26, 2006 special meeting of unitholders. On September 26, 2006, the defendants advised the Court that we would provide to our unitholders specified supplemental disclosures, which were included in the Form 8-K and supplemental proxy materials we filed with the SEC on October 5, 2006. In light of the foregoing, we believe that the plaintiff's motion requesting the Court to schedule a hearing to consider his motion to enjoin the special meeting is moot. The special meeting was convened on October 26, 2006, and adjourned, without voting on the proposals, to November 30, 2006 by the General Partner for lack of a quorum. 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 pipelines and other 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 a material adverse effect on our business, financial position, results of operations and cash flows. At September 30, 2006, and December 31, 2005, we have an accrued liability of $1.9 million and $2.4 million, respectively, related to sites requiring environmental remediation activities.

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 September 30, 2006, we have an accrued liability of $0.1 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 have agreed with the DOJ on a proposed penalty of $2.865 million, along with our commitment to implement additional spill prevention measures, and expect to finalize the settlement in the fourth quarter of 2006. 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 resulted in claims by neighboring landowners that have been settled for approximately $0.7 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 were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to 100%. 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 penalty of $0.1 million. The settlement of this citation did not have a material adverse effect on our financial position, results of operations or cash flows.

We are also in negotiations with the U.S. Department of Transportation with respect to a notice of probable violation that we received on April 25, 2005, for alleged violations of pipeline safety regulations at our Todhunter facility, with a proposed $0.4 million civil penalty. We responded on June 30, 2005, by admitting certain of the alleged violations, contesting others and requesting a reduction in the proposed civil penalty. 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.

The FERC, pursuant to the Interstate Commerce Act of 1887, as amended, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under that Act, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months and can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured. The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow. Challenges to our tariff rates could be filed with the FERC.

The intrastate liquids pipeline transportation service we provide is subject to various state laws and regulations that affect the rates we charge and terms and conditions of that service. Although state regulation typically is less onerous than FERC regulation, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of September 30, 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 September 30, 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 $4.4 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, depending upon the nature of the catastrophic event.

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 FTC delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner cooperated fully with this investigation.

On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order requires the divestiture of our 50% interest in MB Storage and certain related assets to one or more FTC-approved buyers no later than December 31, 2006 in a manner approved by the FTC and subject to its final approval. If we are unable to divest the interest and related assets by that date, the FTC may appoint a divestiture trustee to oversee their sale to one or more approved buyers. The order contains no minimum price for the divestiture and requires that we provide the acquirer or acquirers the opportunity to hire employees who spend more than 10% of their time working on the divested assets. The order also imposes specified operational, reporting and consent requirements on us including, among other things, in the event that we build a new pipeline connecting to our mainline at Mont Belvieu, implement new allocation procedures relating to the movement of NGLs between storage facilities, our mainline and customers, or acquire interests in or operate salt dome storage facilities for NGLs in specified areas.

NOTE 15. 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 nine months ended September 30, 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 and December 2007. 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 beginning in the third quarter of 2006.

The accumulated balance of other comprehensive loss related to our cash flow hedge is as follows (in thousands):

Balance at December 31, 2005	$	11
Changes in fair values of interest rate cash flow hedges		(584)
Changes in fair values of crude oil cash flow hedges		234
Balance at September 30, 2006	$	(339)

NOTE 16. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Val Verde Gas Gathering Company, L.P., have issued full, unconditional, and joint and several guarantees of our Senior Notes and our Revolving Credit Facility (collectively "the Guaranteed Debt"). In addition, during the 2005 periods presented below and extending through July 31, 2006, Jonah Gas Gathering Company also had provided the same guarantees of our Guaranteed Debt. Effective August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah Gas Gathering

Company (see Note 8). Jonah Gas Gathering Company was released as a guarantor of the Guaranteed Debt, effective upon the formation of the joint venture.

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.

	September 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 32,286	$ 56,235	$ 807,624	$ (27,736)	$ 868,409
Property, plant and equipment – net	—	945,225	662,607	—	1,607,832
Equity investments	1,335,767	1,149,433	198,613	(1,667,682)	1,016,131
Intercompany notes receivable	1,084,907	—	—	(1,084,907)	—
Intangible assets	—	159,227	30,361	—	189,588
Other assets	5,915	21,207	58,903	—	86,025
Total assets	$ 2,458,875	$ 2,331,327	$ 1,758,108	$ (2,780,325)	$ 3,767,985
Liabilities and partners' capital					
Current liabilities	$ 36,335	$ 87,120	$ 844,988	$ (30,306)	$ 938,137
Long-term debt	1,086,017	386,058	—	—	1,472,075
Intercompany notes payable	—	648,663	436,246	(1,084,909)	—

Deferred tax liability	—	638	19	—	657
Other long term liabilities	1,369	18,171	2,177	—	21,717
Total partners' capital	1,335,154	1,190,677	474,678	(1,665,110)	1,335,399
Total liabilities and partners' capital	$ 2,458,875	$ 2,331,327	$ 1,758,108	$ (2,780,325)	$ 3,767,985

	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 September 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 85,938	$ 2,484,528	$ (421)	$ 2,570,045
Costs and expenses	—	69,040	2,449,601	(421)	2,518,220
Gains on sales of assets	—	(14)	—	—	(14)
Operating income	—	16,912	34,927	—	51,839
Interest expense – net	—	(14,586)	(8,595)	—	(23,181)
Equity earnings	41,145	38,603	2,962	(71,143)	11,567
Other income – net	—	356	707	—	1,063
Income before deferred income tax expense	41,145	41,285	30,001	(71,143)	41,288
Deferred income tax expense	—	140	3	—	143
Income from continuing operations	41,145	41,145	29,998	(71,143)	41,145
Discontinued operations	—	—	—	—	—
Net income	$ 41,145	$ 41,145	$ 29,998	$ (71,143)	$ 41,145

	Three Months Ended September 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 104,059	$ 2,396,410	$ (342)	$ 2,500,127
Costs and expenses	—	74,782	2,382,340	(342)	2,456,780
Gains on sales of assets	—	(24)	(7)	—	(31)
Operating income	—	29,301	14,077	—	43,378
Interest expense – net	—	(12,476)	(7,250)	—	(19,726)
Equity earnings	29,575	11,723	5,398	(41,949)	4,747
Other income – net	—	335	149	—	484
Income from continuing operations	29,575	28,883	12,374	(41,949)	28,883
Discontinued operations	—	692	—	—	692
Net income	$ 29,575	$ 29,575	$ 12,374	$ (41,949)	$ 29,575

	Nine Months Ended September 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 257,078	$ 7,282,867	$ (8,479)	$ 7,531,466
Costs and expenses	—	207,291	7,161,417	(8,479)	7,360,229

Gains on sales of assets	—	(1,410)	—	—	(1,410)
Operating income	—	51,197	121,450	—	172,647
Interest expense – net	—	(37,756)	(25,766)	—	(63,522)
Equity earnings	145,483	130,883	10,257	(271,393)	15,230
Other income – net	—	1,299	1,117	—	2,416
Income before deferred income tax expense	145,483	145,623	107,058	(271,393)	126,771
Deferred income tax expense	—	140	517	—	657
Income from continuing operations	145,483	145,483	106,541	(271,393)	126,114
Discontinued operations	—	—	19,369	—	19,369
Net income	$ 145,483	$ 145,483	$ 125,910	$ (271,393)	$ 145,483

	Nine Months Ended September 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 319,832	$ 5,793,862	$ (2,391)	$ 6,111,303
Costs and expenses	—	207,991	5,747,873	(2,391)	5,953,473
Gains on sales of assets	—	(538)	(59)	—	(597)
Operating income	—	112,379	46,048	—	158,427
Interest expense – net	—	(39,751)	(20,889)	—	(60,640)
Equity earnings	117,926	41,956	19,310	(162,600)	16,592
Other income – net	—	680	205	—	885
Income from continuing operations	117,926	115,264	44,674	(162,600)	115,264
Discontinued operations	—	2,662	—	—	2,662
Net income	$ 117,926	$ 117,926	$ 44,674	$ (162,600)	$ 117,926

	Nine Months Ended September 30, 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	$ 145,483	$ 145,483	$ 125,910	$ (271,393)	$ 145,483
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	—	(19,369)	—	(19,369)
Deferred income tax expense	—	140	517	—	657
Depreciation and amortization	—	53,236	30,447	—	83,683
Earnings in equity investments, net of distributions	60,693	10,125	5,061	(64,563)	11,316
Gains on sales of assets	—	(1,410)	—	—	(1,410)
Changes in assets and liabilities and other	51,523	(26,087)	18,315	(33,098)	10,653
Net cash provided by continuing operating activities	257,699	181,487	160,881	(369,054)	231,013
Cash flows from discontinued operations	—	—	1,521	—	1,521
Net cash provided by operating activities	257,699	181,487	162,402	(369,054)	232,534
Cash flows from investing activities	(195,072)	34,715	(54,333)	40,131	(174,559)
Cash flows from financing activities	(58,004)	(216,190)	(108,098)	324,288	(58,004)
Net increase (decrease) in cash and cash equivalents	4,623	12	(29)	(4,635)	(29)
Cash and cash equivalents at beginning of period	1,978	—	107	(1,966)	119
Cash and cash equivalents at end of period	$ 6,601	$ 12	$ 78	$ (6,601)	$ 90

	Nine Months Ended September 30, 2005				
	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	$ 117,926	$ 117,926	$ 44,674	$ (162,600)	$ 117,926

Adjustments to reconcile net income to net cash provided by (used in) continuing operating activities:					
Income from discontinued operations	—	(2,662)	—	—	(2,662)
Depreciation and amortization	—	61,114	21,442	—	82,556
Earnings (losses) in equity investments, net of distributions	66,282	6,542	(1,820)	(59,418)	11,586
Gains on sales of assets	—	(538)	(59)	—	(597)
Changes in assets and liabilities and other	(108,054)	(52,375)	(108,222)	105,804	(162,847)
Net cash provided by (used in) continuing operating activities	76,154	130,007	(43,985)	(116,214)	45,962
Cash flows from discontinued operations	—	3,110	—	—	3,110
Net cash provided by (used in) operating activities	76,154	133,117	(43,985)	(116,214)	49,072
Cash flows from investing activities	(278,830)	(21,909)	(149,873)	183,069	(267,543)
Cash flows from financing activities	202,121	(124,614)	191,061	(66,447)	202,121
Net decrease in cash and cash equivalents	(555)	(13,406)	(2,797)	408	(16,350)
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	$ 3,561	$ 190	$ 29	$ (3,708)	$ 72

NOTE 17. SUBSEQUENT EVENTS

On October 6, 2006, we sold certain crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, to an affiliate of Enterprise for approximately $11.7 million. These assets, which have been idle since acquisition, were part of the assets acquired by us in 2005 from Genco and BP (see Note 5). The sales proceeds will be used to fund organic growth projects, retire debt or for other general partnership purposes. The carrying value of these pipeline assets at September 30, 2006, was approximately $5.6 million.

During October 2006, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $200.0 million. These agreements, which are a series of derivative instruments, hedge our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.7%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security.

On November 1, 2006, we announced plans to construct a new 20-inch diameter lateral pipeline that will connect our mainline system to Enterprise's storage facility at Mont Belvieu, Texas. The new connection, which will provide delivery of propane into our system at full line flow rates, complements our current ability to source product from MB Storage. The new lateral will also offer the ability to deliver other liquid products such as butanes and

natural gasoline from Enterprise's storage facilities into our system at reduced flow rates until enhancements can be made. The capability to deliver butanes and natural gasoline from MB Storage at full flow rates is not expected to be impacted. Construction of the new connection is expected to be completed around January 1, 2007.

Effective November 1, 2006, we purchased a refined petroleum product terminal in Aberdeen, Mississippi, for approximately $5.8 million from Mississippi Terminal and Marketing Inc. ("MTMI"). The facility, located along the Tennessee/TomBigbee waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we plan to integrate into our Downstream Segment, we plan to construct a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $25.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the fourth quarter of 2007.

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 Current Report on Form 8-K filed on June 16, 2006, which recast certain information from our Annual Report on Form 10-K for the year ended December 31, 2005, as discontinued operations. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements
- Overview of Critical Accounting Policies and Estimates
- Overview of Business

- 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 future distributions, 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 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 caption "Risk Factors" in our Quarterly Report on Form 10-Q for the period ended June 30, 2006 and in this Report; under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Current Report on Form 8-K filed on June 16, 2006; and 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 Report and in our future periodic reports filed with the Securities and Exchange Commission ("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, and in our Current Report on Form 8-K filed on June 16, 2006. 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 business strategy is to continue to increase 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 a balanced 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, liquefied petroleum 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 natural gas liquids ("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 in this segment during the first and fourth quarters of each year since these 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 Mont Belvieu Storage Partners, L.P. ("MB Storage"), which we are required to divest (see Note 14 in the Notes to the Consolidated Financial Statements), and in Centennial Pipeline LLC ("Centennial") (see Note 8 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 Crude Pipeline Company ("Seaway") (see Note 8 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 coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde Gas Gathering Company, L.P. ("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. Our Midstream Segment also includes our equity investment in Jonah Gas Gathering Company ("Jonah") (see Note 8 in the Notes to the Consolidated Financial Statements). Jonah, which is a joint venture between us and an affiliate of Enterprise Products Partners L.P. ("Enterprise"), owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise's affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which we sold to an Enterprise affiliate in March 2006, are shown as discontinued operations for the three months and nine months ended September 30, 2006 and 2005.

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 continue to believe that our business strategy will provide continued growth in earnings and cash distributions. Based on a detailed analysis of the business environment, our management has identified key trends or factors, each of which, in turn, drive our growth strategy beyond organic growth as follows:

- We expect that Canadian crude oil imports to the U.S. will increase.
  - Develop competitive option to move Canadian crude oil to U.S. refining customers through an optimum combination of new pipeline construction and/or existing pipeline assets with third parties.

- We expect that crude oil imports to the U.S. Gulf Coast will increase.
  - Build onshore or offshore crude oil discharge, handling and transportation facilities to optimize the U.S. Gulf Coast marine delivery options for imported crude oil.
- We expect that refined products imports to the U.S. will increase.
  - Acquire or develop facilities to take advantage of these increased volumes.
- We expect to see changes in commercial terminal ownership and operations.
  - Acquire refined products terminals and distribution assets to provide logistical service offerings to companies seeking to outsource or partner.
- Ethanol consumption is mandated to double by 2012.
  - Participate in the aggregation, terminaling and transportation associated with the overall supply and distribution of ethanol.
- We expect to see continued natural gas gathering and service opportunities in the Jonah, Pinedale and San Juan Basin areas.
  - Continued development and expansion of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment. Through additional Jonah expansions, which should be completed in the fourth quarter of 2007, we expect to increase the capacity to 2.4 billion cubic feet per day.
  - 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.

We also believe other growth opportunities are available to us, including through: expanding our West Texas system and storage capacity at Cushing in our Upstream Segment; increasing throughput on our Midstream Segment NGL systems; expanding our Downstream Segment system delivery capability of gasoline and diesel fuel in the Indianapolis and Chicago market areas; utilizing available Downstream Segment system capacity of Centennial to move refined products to Midwest market areas, which enables us to increase movements of long-haul propane volumes; expanding our Downstream Segment gathering capacity of refined products along the upper Texas Gulf Coast; and pursuing acquisitions or organic growth projects in any of our business segments that would complement our current operations.

For additional 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 Quarterly Report on Form 10-Q for the period ended June 30, 2006.

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 received 60% of revenue and expense of Seaway. Thereafter, we receive 40% of revenue and expense of Seaway. Our share of revenue and expense of Seaway is 47% for 2006 (see Note 8 in the Notes to the Consolidated Financial Statements).

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.

Jonah Joint Venture

On August 1, 2006, Enterprise Products Partners L.P. ("Enterprise"), through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the partnership through which we owned the Jonah system. Prior to entering into the Jonah joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet ("Bcf") per day to

approximately 2.4 Bcf per day and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf per day, is scheduled to be completed in the first quarter of 2007 at an estimated cost of approximately $295.0 million. The second portion of the expansion is expected to cost approximately $170.0 million and be completed by the end of 2007. The overall high level of activity in the greater Green River Basin area has strained locally available resources, including equipment and qualified personnel. Coupled with rising steel costs, these factors are likely to contribute to higher overall costs for the Jonah expansion than previously anticipated. We expect to reimburse Enterprise for approximately 50% of these costs.

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point, Enterprise will be entitled to receive approximately 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. In the third quarter of 2006, we reimbursed Enterprise $65.0 million for 50% of the Phase V cost incurred by it through August 1, 2006 (including its cost of capital of $1.3 million). At September 30, 2006, we had a payable to Enterprise for costs incurred through September 30, 2006, of $18.9 million. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on the formula in the partnership agreement, we expect to own an interest in Jonah of approximately 80%, with Enterprise owning the remaining 20% and serving as operator, with further costs being allocated based on such ownership interests. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner.

Effective August 1, 2006, with the formation of the joint venture, Jonah was deconsolidated, and we began using the equity method of accounting to account for our investment in Jonah. Under the equity method, we record the costs of our investment within the "Equity Investments" line on our consolidated balance sheet, and as changes in the net assets of Jonah occur (for example, earnings, contributions and distributions), we will recognize our proportional share of that change in the "Equity Investments" account.

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 reduce the General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to reduce its maximum percentage interest in our quarterly distributions, our General Partner would receive a number of newly-issued Units that, based on the distribution rate and the number of Units outstanding at the time of issuance, would result in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions that would approximately equal the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without reduction. Based on our distribution rate and outstanding Units as of the date of the filing of this Report, the number of newly-issued Units issued to the General Partner would be approximately 14.1 million. On September 11, 2006, we filed with the Securities and Exchange Commission a definitive proxy statement that outlines the EPCO proposal to be voted upon at a special meeting of our unitholders and other changes to our Partnership Agreement that are part of the EPCO proposal, all of which are conditioned upon one another. Passage of the components of the EPCO proposal effectively requires the affirmative vote of 66 2/3% of our outstanding Units (issuance of Units to the General Partner requires a majority of the votes cast by a quorum of our unitholders, but that proposal is conditioned on passage of the changes to our Partnership Agreement, which require the 66 2/3% approval). The proxy statement also contains separate proposals for the adoption of an employee Unit purchase plan and a long term incentive plan. The special meeting was convened on October 26, 2006, and adjourned, without voting on the proposals, to November 30, 2006 by the General Partner for lack of a quorum.

Recent Developments

On November 1, 2006, we announced plans to construct a new 20-inch diameter lateral pipeline that will connect our mainline system to Enterprise's storage facility at Mont Belvieu, Texas. The new connection, which will provide delivery of propane into our system at full line flow rates, complements our current ability to source product from MB Storage. The new lateral will also offer the ability to deliver other liquid products such as butanes and natural gasoline from Enterprise's storage facilities into our system at reduced flow rates until enhancements can be made. The capability to deliver butanes and natural gasoline from MB Storage at full flow rates is not expected to be impacted. Construction of the new connection is expected to be completed around January 1, 2007.

Effective November 1, 2006, we purchased a refined petroleum product terminal in Aberdeen, Mississippi, for approximately $5.8 million from Mississippi Terminal and Marketing Inc. ("MTMI"). The facility, located along the Tennessee/TomBigbee waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we plan to integrate into our Downstream Segment, we plan to construct a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $25.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the fourth quarter of 2007.

Results of Operations

The following table summarizes financial information by business segment for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Operating revenues:				
Downstream Segment	$ 72,358	$ 66,094	$ 215,758	$ 207,699
Upstream Segment	2,453,926	2,380,734	7,152,520	5,750,514
Midstream Segment (1)	43,895	53,641	170,617	155,481
Intersegment eliminations	(134)	(342)	(7,429)	(2,391)
Total operating revenues	2,570,045	2,500,127	7,531,466	6,111,303
Operating income:				
Downstream Segment	19,586	14,615	59,641	61,099
Upstream Segment	19,446	5,207	53,097	22,199
Midstream Segment (1)	12,798	23,556	59,900	75,129
Intersegment eliminations	9	—	9	—
Total operating income	51,839	43,378	172,647	158,427
Equity earnings (losses):				
Downstream Segment	(2,949)	(651)	(6,581)	(2,718)
Upstream Segment	2,962	5,398	10,257	19,310
Midstream Segment (1)	11,563	—	11,563	—
Intersegment eliminations	(9)	—	(9)	—
Total equity earnings	11,567	4,747	15,230	16,592
Earnings before interest:				
Downstream Segment	16,926	14,270	54,313	58,957
Upstream Segment	22,752	10,708	63,967	41,641
Midstream Segment (1)	24,791	23,631	72,013	75,306
Interest expense	(24,884)	(22,033)	(71,642)	(65,202)
Interest capitalized	1,703	2,307	8,120	4,562
Income before deferred income tax expense	41,288	28,883	126,771	115,264
Deferred income tax expense	143	—	657	—
Income from continuing operations	41,145	28,883	126,114	115,264
Discontinued operations	—	692	19,369	2,662
Net income	$ 41,145	$ 29,575	$ 145,483	$ 117,926

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 8 in the Notes to the Consolidated Financial Statements).

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

Downstream Segment

The following table provides financial information for the Downstream Segment for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended	Nine Months Ended

	September 30, 2006	September 30, 2005	Increase (Decrease)	September 30, 2006	September 30, 2005	Increase (Decrease)
Revenues:						
Transportation – Refined products	$ 42,067	$ 38,240	$ 3,827	$ 113,309	$ 111,039	$ 2,270
Transportation – LPGs	16,877	16,519	358	59,652	63,220	(3,568)
Other	13,414	11,335	2,079	42,797	33,440	9,357
Total operating revenues	72,358	66,094	6,264	215,758	207,699	8,059
Costs and expenses:						
Operating expense	27,799	25,602	2,197	77,606	72,787	4,819
Operating fuel and power	10,560	8,170	2,390	28,183	23,787	4,396
General and administrative	3,455	4,617	(1,162)	13,250	12,328	922
Depreciation and amortization	10,713	10,098	615	31,143	29,460	1,683
Taxes – other than income taxes	259	3,016	(2,757)	5,974	8,369	(2,395)
Gains on sales of assets	(14)	(24)	10	(39)	(131)	92
Total costs and expenses	52,772	51,479	1,293	156,117	146,600	9,517
Operating income	19,586	14,615	4,971	59,641	61,099	(1,458)
Equity losses	(2,949)	(651)	(2,298)	(6,581)	(2,718)	(3,863)
Other income – net	289	306	(17)	1,253	576	677
Earnings before interest	$ 16,926	$ 14,270	$ 2,656	$ 54,313	$ 58,957	$ (4,644)

The following table presents volumes delivered in barrels and average tariff per barrel for the three months and nine months ended September 30, 2006 and 2005 (in thousands, except tariff information):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Percentage Increase (Decrease)	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Percentage Increase (Decrease)
Volumes Delivered:						
Refined products	43,018	43,067	—	125,061	123,759	1%
LPGs	9,763	8,646	13%	30,880	31,303	(1)%
Total	52,781	51,713	2%	155,941	155,062	1%
Average Tariff per Barrel:						
Refined products	$ 0.98	$ 0.89	10%	$ 0.91	$ 0.90	1%
LPGs	1.73	1.91	(9)%	1.93	2.02	(4)%
Average system tariff per barrel	1.12	$ 1.06	6%	1.11	$ 1.12	(1)%

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

Revenues from refined products transportation increased $3.8 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to a 10% increase in the refined products average tariff per barrel. The average tariff increased primarily due to an increase in gasoline blendstock deliveries, which have a higher tariff, an increase in system tariffs, which went into effect in April and July 2006, and a shift of volumes from Centennial to TEPPCO tariffs. Overall, refined products volumes remained effectively unchanged between periods. Increases in jet fuel and gasoline blendstock deliveries were offset by lower distillate deliveries. Short-haul deliveries of product received into our system from Centennial at Creal Springs, Illinois, also decreased. Centennial, through a lease agreement entered into in February 2003, provides 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. The Centennial capacity lease has relieved our previously constrained system and has permitted 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 of the TEPPCO system for delivery to the south end of our system.

Revenues from LPGs transportation increased $0.4 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, due to an increase in short-haul propane deliveries on the Texas Gulf Coast. The LPGs average rate per barrel decreased from the prior period primarily as a result of these increased short-haul deliveries during the three months ended September 30, 2006, compared with the three months ended September 30, 2005.

Other operating revenues increased $2.1 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to increased storage revenues on assets acquired from Texas Genco, LLC in July 2005 and higher other system storage revenues, partially offset by decreased volumes of product sales.

Costs and expenses increased $1.3 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Operating fuel and power increased $2.4 million primarily due to increased mainline throughput and higher power rates. Operating expenses increased $2.2 million primarily due to a $1.5 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005, a $0.7 million increase in rental expense on a lease with a third-party pipeline, a $0.6 million increase in rental expense from the Centennial pipeline capacity lease agreement and $0.6 million of higher insurance premiums. These increases in operating expenses were partially offset by a $0.8 million decrease due to regulatory penalties in the prior year period and a $0.6 million decrease in pipeline inspection and repair costs associated with our integrity management program. Depreciation and amortization expense increased $0.6 million primarily due to assets placed into service and asset retirements during the 2006 period. Taxes – other than income taxes decreased $2.7 million primarily due to a true-up of property tax accruals for prior tax years and higher payroll taxes in the prior year period. General and administrative expenses decreased $1.2 million primarily due to higher labor and benefits expenses in the prior year period associated with vesting provisions in certain of our incentive compensation plans and changes in ownership of our General Partner. These costs and expenses were offset by higher expenses relating to our special unitholder meeting to consider EPCO's proposals to amend and restate our Partnership Agreement and issue Units to our General Partner, as well as other proposals, and higher executive compensation expense.

Net losses from equity investments increased for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, as shown below (in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Increase (Decrease)
Centennial	$ (4,065)	$ (2,391)	$ (1,674)
MB Storage	1,122	1,728	(606)
Other	(6)	12	(18)
Total equity losses	$ (2,949)	$ (651)	$ (2,298)

Equity losses in Centennial increased $1.7 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to lower transportation volumes and increased costs relating to pipeline inspection and repair costs associated with its integrity management program. Equity earnings in MB Storage decreased $0.6 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to higher product measurement losses on the MB

Storage system and higher operating fuel and power resulting from higher power rates and increased volumes, partially offset by higher revenues.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Revenues from refined products transportation increased $2.3 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to a slight overall increase in refined products volumes transported and a minor increase in the average rate per barrel. Volume increases were due to increased demand for products supplied from the U.S. Gulf Coast into Midwest markets resulting from higher distillate price differentials and a greater demand for gasoline blendstocks, partially offset by unfavorable differentials for motor fuels during the first quarter of 2006. Additionally, refined products revenues increased due to increased terminaling activity at truck racks and higher product storage fees. The average tariff increased primarily due to an increase in gasoline blendstock deliveries, which have a higher tariff, and an increase in system tariffs, which went into effect in April and July 2006. The increase in the refined products average tariff rate is partially offset by the impact of Centennial on the average rates. When a larger proportion of the refined products deliveries are delivered under a Centennial tariff, TEPPCO's average tariff declines. Conversely, if the proportion of refined products deliveries moving under a Centennial origin decrease, the average TEPPCO tariff increases. Movements of refined products on Centennial therefore result 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 $3.6 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of warmer than normal winter weather in the first quarter of 2006, high propane prices and scheduled plant maintenance, known as a turnaround. The LPGs average rate per barrel decreased from the prior year period primarily as a result of increased short-haul deliveries during the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005.

Other operating revenues increased $9.4 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to increased storage revenue on assets acquired from Texas Genco, LLC in July 2005 and increases in other system storage and tender deduction revenues.

Costs and expenses increased $9.5 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Operating expenses increased $4.8 million primarily due to a $7.8 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005, $2.1 million of higher insurance premiums, a $0.7 million increase in rental expense on a lease with a third-party pipeline, $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO, $0.4 million of expenses relating to our special unitholder meeting ("– EPCO Proposal," above) and a $0.3 million increase in environmental remediation and assessment costs. These increases in costs and expenses were partially offset by a $3.5 million decrease in pipeline inspection and repair costs associated with our integrity management program, $1.4 million in product measurement gains, a $1.0 million decrease in labor and benefits expense associated with incentive compensation plan vestings in the prior year period and a $0.8 million decrease in regulatory penalties for past incidents. Operating fuel and power increased $4.4 million primarily due to increased mainline throughput and higher power rates. Depreciation expense increased $1.7 million primarily due to assets placed into service, asset retirements in 2006 and the recording of a conditional asset retirement obligation as discussed below. General and administrative expenses increased $0.9 million primarily due to a $1.1 million increase related to the retirement of an executive in February 2006, $0.7 million in severance expense as a result of the migration to a shared services environment with EPCO and higher executive compensation expense, partially offset by higher labor and benefits expenses in the prior year period associated with vesting provisions in certain of our incentive compensation plans and changes in ownership of our General Partner resulting in higher incentive compensation expenses for that period. Taxes – other than income taxes decreased $2.4 million primarily due to a true-up of property tax accruals for prior tax years and higher payroll taxes in the prior year period.

Net losses from equity investments increased for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, as shown below (in thousands):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Increase (Decrease)
Centennial	$ (11,378)	$ (8,476)	$ (2,902)
MB Storage	4,814	5,727	(913)
Other	(17)	31	(48)
Total equity losses	$ (6,581)	$ (2,718)	$ (3,863)

Equity losses in Centennial increased $2.9 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to lower propane revenues and volumes primarily due to warmer than normal winter weather in the Northeast in the 2006 period and increased costs relating to pipeline inspection and repair costs associated with its integrity management program, partially offset by lower amortization expense on the portion of TE Products' excess investment in Centennial as a result of the lower volumes. Equity earnings in MB Storage decreased $0.9 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to higher product measurement losses on the MB Storage system, higher system maintenance expenses and higher operating fuel and power resulting from higher power rates and increased volumes, partially offset by higher revenues.

Other income – net increased $0.7 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, due to higher interest income earned on cash investments and other investing activities.

Asset Retirement Obligation

During the second quarter of 2006, we recorded $0.3 million of expense, included in depreciation and amortization expense, related to a conditional asset retirement obligation. Additionally, we recorded a $0.4 million liability, which represents the fair value of the conditional asset retirement obligation related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination (see Note 1 in the Notes to the Consolidated Financial Statements).

Upstream Segment

The following table provides financial information for the Upstream Segment for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Increase (Decrease)	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Increase (Decrease)
Revenues:						
Sales of petroleum products (1)	$ 2,441,750	$ 2,367,984	$ 73,766	$ 7,116,064	$ 5,714,353	$ 1,401,711
Transportation – Crude oil	9,567	10,001	(434)	29,034	28,215	819
Other	2,609	2,749	(140)	7,422	7,946	(524)
Total operating revenues	2,453,926	2,380,734	73,192	7,152,520	5,750,514	1,402,006
Costs and expenses:						
Purchases of petroleum products (1)	2,413,391	2,350,107	63,284	7,032,930	5,665,136	1,367,794
Operating expense	12,974	14,216	(1,242)	40,955	37,217	3,738
Operating fuel and power	1,511	1,247	264	5,470	3,709	1,761
General and administrative	1,460	1,756	(296)	5,137	4,483	654
Depreciation and amortization	3,699	6,471	(2,772)	10,464	13,623	(3,159)
Taxes – other than income taxes	1,445	1,737	(292)	4,467	4,206	261
Gains on sales of assets	—	(7)	7	—	(59)	59
Total costs and expenses	2,434,480	2,375,527	58,953	7,099,423	5,728,315	1,371,108
Operating income	19,446	5,207	14,239	53,097	22,199	30,898
Equity earnings	2,962	5,398	(2,436)	10,257	19,310	(9,053)
Other income – net	344	103	241	613	132	481
Earnings before interest	$ 22,752	$ 10,708	$ 12,044	$ 63,967	$ 41,641	$ 22,326

(1) Amounts for the three months ended September 30, 2006 have been fully adjusted for the impact of adopting Emerging Issues Task Force ("EITF") 04-13. Amounts for the nine months ended September 30, 2006 have been adjusted for the period from April 1, 2006 through September 30, 2006 for the impact of adopting EITF 04-13. The 2005 periods have not been adjusted for the adoption of EITF 04-13, as retroactive restatement was not permitted, which impacts comparability (for further discussion, see below).

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 because it excludes expenses that are not directly related to the marketing and sales activities being evaluated. Margin and volume information for the three months and nine months ended September 30, 2006 and 2005 is presented below (in thousands, except per barrel and per gallon amounts):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Percentage Increase (Decrease)	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Percentage Increase (Decrease)
Margins: (1)						
Crude oil marketing	$ 14,675	$ 7,750	89%	$ 46,557	$ 20,282	130%
Lubrication oil sales	2,221	1,951	14%	6,396	5,383	19%
Revenues: (1)						
Crude oil transportation	18,162	15,416	18%	50,516	44,537	13%
Crude oil terminaling	2,868	2,761	4%	8,699	7,230	20%
Total margins/revenues	$ 37,926	$ 27,878	36%	$ 112,168	$ 77,432	45%
Total barrels/gallons:						
Crude oil marketing (barrels)	57,982	54,747	6%	167,180	147,905	13%
Lubrication oil volume (gallons)	3,457	3,573	(3)%	10,689	10,898	(2)%
Crude oil transportation (barrels)	23,237	23,659	(2)%	68,412	71,181	(4)%
Crude oil terminaling (barrels)	30,181	28,528	6%	92,929	76,934	21%
Margin per barrel or gallon:						
Crude oil marketing (per barrel)	$ 0.253	$ 0.142	79%	$ 0.278	$ 0.137	103%
Lubrication oil margin (per gallon)	0.642	0.546	18%	0.598	0.494	21%
Average tariff per barrel:						
Crude oil transportation	$ 0.782	$ 0.652	20%	$ 0.738	$ 0.626	18%
Crude oil terminaling	0.095	0.097	(2)%	0.094	0.094	—

(1) Amounts 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 using the information presented in the consolidated statements of income and the statements of income in Note 13 in the Notes to the Consolidated Financial Statements (in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Sales of petroleum products	$ 2,441,750	$ 2,367,984	$ 7,116,064	$ 5,714,353
Transportation – Crude oil	9,567	10,001	29,034	28,215
Less: Purchases of petroleum products	(2,413,391)	(2,350,107)	(7,032,930)	(5,665,136)
Total margins/revenues	37,926	27,878	112,168	77,432
Other operating revenues	2,609	2,749	7,422	7,946
Net operating revenues	40,535	30,627	119,590	85,378
Operating expense	12,974	14,216	40,955	37,217
Operating fuel and power	1,511	1,247	5,470	3,709
General and administrative expense	1,460	1,756	5,137	4,483
Depreciation and amortization	3,699	6,471	10,464	13,623
Taxes – other than income taxes	1,445	1,737	4,467	4,206
Gains on sales of assets	—	(7)	—	(59)
Operating income	$ 19,446	$ 5,207	$ 53,097	$ 22,199

On April 1, 2006, we adopted EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (see Note 1 in the Notes to the Consolidated Financial Statements), which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. EITF 04-13 reduced gross

revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our consolidated statements of income by approximately $774.4 million for the period from April 1, 2006 through September 30, 2006 ($460.7 million for the three months ended September 30, 2006). The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our consolidated statements of income for the three months and nine months ended September 30, 2005, and for the period from January 1, 2006 through March 31, 2006, are approximately $494.7 million, $898.0 million and $275.4 million, respectively. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted.

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

Sales of petroleum products increased $73.8 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Purchases of petroleum products increased $63.3 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Operating income increased $14.2 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. The increases in sales and purchases were primarily as a result of an increase in the price of crude oil and increased volumes marketed, partially offset by the effects of the adoption of EITF 04-13, which reduced each of revenues and purchases of petroleum products by $460.7 million for the three months ended September 30, 2006. The average NYMEX price of crude oil was $70.54 per barrel for the three months ended September 30, 2006, compared with $63.31 per barrel for the three months ended September 30, 2005. The increase in the average price of crude oil and decreased costs and expenses discussed below, partially offset by increased purchases of petroleum products were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $6.9 million primarily due to favorable market conditions and increased volumes marketed and unrealized losses in the 2005 period of $1.2 million related to marking crude oil grade and location swap contracts to current market value, partially offset by increased transportation costs. Crude oil transportation revenues increased $2.7 million primarily due to increased transportation revenues on the Red River system, the South Texas system and the Basin system primarily related to movements on higher tariff segments, increased tariffs and revenues from systems acquired during 2005 and increases due to organic growth projects, partially offset by decreases in transportation volumes on lower tariff segments of our Red River system and lower third-party transportation volumes. Lubrication oil sales margin increased $0.3 million due to increased fuel and lubrication oil volumes and higher margins per gallon on sales of lubrication oils. Crude oil terminaling revenues increased $0.1 million as a result of increased pumpover volumes at Midland, Texas, partially offset by decreased pumpover volumes at Cushing, Oklahoma and a lower average tariff per barrel.

Other operating revenues decreased $0.2 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to lower revenues from documentation and other services to support customers' trading activity at Midland and Cushing in the third quarter of 2006.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, decreased $4.3 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Depreciation and amortization expense decreased $2.8 million primarily as a result of $2.6 million of asset impairments in the prior year period. Operating expenses decreased $1.2 million from the prior year period primarily due to a $0.5 million decrease in pipeline operating and maintenance expense, a $0.4 million increase in product measurement gains and a $0.4 million decrease in pipeline operating expense. General and administrative expenses decreased $0.3 million from the prior year period primarily due to reductions in labor and benefits expense related to plan amendments in the prior year period (see Note 12 in the Notes to the Consolidated Financial Statements). Taxes – other than income taxes decreased $0.3 million from the prior year period primarily due to reductions in property tax accruals, partially offset by a higher property asset base in 2006. Operating fuel and power increased $0.3 million primarily as a result of higher power rates in the 2006 period.

Equity earnings from our investment in Seaway decreased $2.4 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Our equity earnings in Seaway were reduced in part 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 8 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to decreased transportation volumes and revenues on the long-haul system primarily attributable to higher transportation demand in the prior year period as a result of Hurricanes Katrina and Rita and due to refinery turnarounds in the current period, partially offset by higher operating expenses in the prior year period related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005 and higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates in the prior year period. Long-haul volumes on Seaway averaged 239,000 barrels per day during the three months ended September 30, 2006, compared with 296,000 barrels per day during the three months ended September 30, 2005.

After Seaway's pipeline release in May 2005, the maximum operating pressure on the pipeline system was reduced by 20% until the cause of the failure was determined. Corrective measures were implemented upon the release in 2005 and were completed during the second quarter of 2006. Seaway operated at reduced maximum pressure through May 2006. On June 1, 2006, Seaway's operating pressure was increased to 100%. As a result of operating at reduced maximum pressure, during the third quarter of 2005, we used a drag reducing agent to increase the flow of product through the pipeline system during the period when operating pressures were reduced. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. The reduced pressure did not have a material adverse effect on our financial position, results of operations or cash flows (see Note 14 in the Notes to the Consolidated Financial Statements).

Other income – net increased $0.2 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, due to higher interest income earned on cash investments and other investing activities.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Sales of petroleum products increased $1,401.7 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Purchases of petroleum products increased $1,367.8 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Operating income increased $30.9 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. The increases in sales and purchases were primarily a result of an increase in the price of crude oil and increased volumes marketed, partially offset by the effects of the adoption of EITF 04-13, which reduced each of revenues and purchases of petroleum products by $774.4 million for the nine months ended September 30, 2006. The average NYMEX price of crude oil was $68.25 per barrel for the nine months ended September 30, 2006, compared with $55.52 per barrel for the nine months ended September 30, 2005. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $26.3 million, primarily due to favorable market conditions and increased volumes marketed and a decrease in unrealized losses compared with the 2005 period of $0.3 million relating to marking crude oil grade and location swap contracts to current market value, partially offset by increased transportation costs. Crude oil transportation revenues increased $6.0 million primarily due to higher revenues on our Red River system related to movements on higher tariff segments and revenues from acquisitions in 2005 and increased transportation volumes and revenues on our South Texas system and West Texas systems, partially offset by decreases in transportation volumes on lower tariff segments of our Basin and Red River systems. Crude oil terminaling revenues increased $1.4 million as a result of increased pumpover volumes at Midland, Texas and Cushing, Oklahoma. Lubrication oil sales margin increased $1.0 million due to increased fuel and lubrication oil volumes and higher margins per gallon on sales of lubrication oils.

Other operating revenues decreased $0.5 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to a $1.4 million favorable settlement of inventory

imbalances in the first quarter of 2005 and lower revenues from documentation and other services to support customers' trading activity at Midland and Cushing in the first nine months of 2006.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $3.3 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Operating expenses increased $3.7 million from the prior year period, primarily due to a $2.5 million increase in pipeline operating and maintenance expense, $0.9 million of higher insurance premiums, a $0.6 million increase as a result of product measurement losses and higher crude oil prices, a $0.6 million increase in environmental assessment and remediation costs and $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO, partially offset by a $0.9 million decrease in labor and benefits expense related to vesting provisions in certain of our compensation plans in the prior year period as a result of changes in ownership of our General Partner and a $0.3 million decrease in costs associated with our integrity management program. Operating fuel and power increased $1.8 million primarily as a result of increased power rates in the 2006 period, partially offset by lower transportation volumes. General and administrative expenses increased $0.7 million from the prior year period primarily due to $0.4 million in severance expense, an increase in executive compensation expense and an increase in consulting and contract services. Taxes – other than income taxes increased $0.3 million due to increases in property tax accruals and a higher property asset base in 2006. Depreciation and amortization expense decreased $3.2 million primarily due to $2.6 million of asset impairments and asset retirements during the prior year period.

Equity earnings from our investment in Seaway decreased $9.1 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. 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 8 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher operating, general and administrative expenses related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs, higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates, a favorable settlement in the first quarter of 2005 with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us and decreased transportation volumes. Long-haul volumes on Seaway averaged 247,000 barrels per day during the nine months ended September 30, 2006, compared with 250,000 barrels per day during the nine months ended September 30, 2005.

Other income – net increased $0.5 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, due to higher interest income earned on cash investments and other investing activities.

Midstream Segment

The following table provides financial information for the Midstream Segment for the three months and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Increase	Nine Months Ended September 30,		Increase
	2006	2005	(Decrease)	2006	2005	(Decrease)
Revenues:						
Sales of petroleum products	$ 4,990	$ —	$ 4,990	$ 18,766	$ —	$ 18,766
Gathering – Natural Gas (1)	25,022	38,833	(13,811)	107,856	112,349	(4,493)
Transportation – NGLs	10,971	11,829	(858)	32,362	33,435	(1,073)
Other	2,912	2,979	(67)	11,633	9,697	1,936
Total operating revenues	43,895	53,641	(9,746)	170,617	155,481	15,136
Costs and expenses (1):						
Purchases of petroleum products	4,323	—	4,323	17,272	—	17,272
Operating expense	8,529	9,415	(886)	33,122	25,625	7,497
Operating fuel and power	3,407	3,121	286	9,109	7,658	1,451
General and administrative expense	2,079	2,144	(65)	6,966	5,011	1,955
Depreciation and amortization	11,838	14,238	(2,400)	42,076	39,473	2,603
Taxes – other than income taxes	921	1,167	(246)	3,543	2,992	551
Gains on sales of assets	—	—	—	(1,371)	(407)	(964)
Total costs and expenses	31,097	30,085	1,012	110,717	80,352	30,365
Operating income	12,798	23,556	(10,758)	59,900	75,129	(15,229)
Equity earnings (1)	11,563	—	11,563	11,563	—	11,563
Other income – net	430	75	355	550	177	373
Earnings before interest	$ 24,791	$ 23,631	$ 1,160	$ 72,013	$ 75,306	$ (3,293)

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and operating results, including revenues and costs and expenses, after August 1, 2006 are included in equity earnings (see Note 8 in the Notes to the Consolidated Financial Statements).

The following table presents volume and average rate information for the Midstream Segment for the three months and nine months ended September 30, 2006 and 2005:

	Three Months Ended September 30,		Percentage Increase (Decrease)	Nine Months Ended September 30,		Percentage Increase (Decrease)
	2006	2005		2006	2005	
Gathering – Natural Gas – Jonah (1):						
Million cubic feet (“MMcf”)	118,739	105,993	12%	338,755	302,388	12%
Billion British thermal units (“BBtu”)	131,188	117,006	12%	374,164	333,823	12%
Average fee per Million British thermal unit (“MMBtu”)	$ 0.204	$ 0.185	10%	$ 0.206	$ 0.187	10%
Gathering – Natural Gas – Val Verde:						
MMcf	45,003	46,265	(3)%	137,291	131,646	4%
BBtu	39,851	40,816	(3)%	121,458	115,685	5%
Average fee per MMBtu	$ 0.408	$ 0.423	(3)%	$ 0.405	$ 0.430	(6)%
Transportation – NGLs:						
Thousand barrels	18,008	16,332	10%	51,542	45,708	13%
Average rate per barrel	$ 0.609	$ 0.724	(16)%	$ 0.628	$ 0.731	(14)%
Natural Gas Sales:						
BBtu	3,537	—	—	6,164	—	—
Average fee per MMBtu	$ 5.29	$ —	—	$ 5.27	$ —	—
Fractionation – NGLs:						
Thousand barrels	1,034	1,068	(3)%	3,311	3,294	1%
Average rate per barrel	$ 1.633	$ 1.768	(8)%	$ 1.655	$ 1.744	(5)%
Sales – Condensate (1):						
Thousand barrels	2.7	3.4	(20)%	45.7	44.6	3%
Average rate per barrel	$ 70.37	$ 55.60	27%	$ 65.81	$ 50.21	31%

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and operating results after August 1, 2006 are included in equity earnings (see Note 8 in the Notes to the Consolidated Financial Statements). However, the table includes Jonah’s volume and average rate information for the full three and nine month periods ended September 30, 2006 and 2005.

Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah, the partnership through which we owned the Jonah system, was deconsolidated and has been subsequently accounted for as an equity investment. Through July 31, 2006, Jonah’s operating results were fully consolidated in the Midstream Segment operating results. Beginning August 1, 2006, Jonah has been accounted for as an equity investment and operating results for Jonah for the period August 1, 2006 through September 30, 2006, are reported as equity earnings. For the period from August 1, 2006 through September 30, 2006, our sharing in the revenues and expenses of Jonah was 100% (see “– Jonah Joint Venture” above for further information).

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

Revenues from the gathering of natural gas decreased $13.8 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Natural gas gathering revenues from the Jonah system decreased $14.2 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $1.4 million primarily due to the Phase IV expansion of the Jonah system completed in February 2006, prior to deconsolidation. The Phase IV 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 gathering volumes averaged 1.3 Bcf per day for the three months ended September 30, 2006, compared with 1.15 Bcf per day for the three months ended September 30, 2005. Jonah’s average natural gas gathering rate per MMBtu increased 10% primarily due to lower system wellhead pressures. Jonah’s volumes gathered increased 12.7 Bcf as a result of the Phase IV expansion for the three months ended September 30, 2006 as compared to the three months ended September 30, 2005. Natural gas gathering revenues from the Val Verde system decreased $1.0 million and volumes gathered decreased 1.3 Bcf for the three months ended September 30, 2006, primarily due to the natural decline of coal bed methane production and a decrease in the average natural gas gathering rate. During the quarter ended September 30, 2006, we received updated limited production estimates from some of the producers on the Val Verde system, which reduced the future production forecast of coal bed methane, which in turn, could result in reduced future revenues from the Val Verde system. This decrease was partially offset by an increase in volumes from a natural gas connection on the Val Verde system and increased volumes from temporary interconnects with third party gatherers in the third quarter of 2006. Val Verde’s average natural gas gathering rate per MMBtu decreased 3% primarily due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system’s average rates.

In May 2006, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate throughput on Jonah. The purchases and sales are generally contracted to occur in the same month to minimize price risk. During the second quarter of 2006, gas purchase and sales contracts were finalized and executed and the marketing of gas on the Jonah system began. Sales from petroleum products relating to the natural gas marketing activities were $5.0 million and purchases of petroleum products were $4.3 million for the period from July 1, 2006 through July 31, 2006. Effective August 1, 2006, with the deconsolidation of Jonah, sales and purchases of natural gas are reported in equity earnings.

Revenues from the transportation of NGLs decreased $0.9 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to a decrease in the average NGL transportation rate per barrel as a result of increased short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola, Wilcox and Dean Pipelines, partially offset by decreased volumes transported on the San Jacinto Pipeline.

Other operating revenues decreased $0.1 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Val Verde's other operating revenue decreased $0.4 million primarily due to a decrease in volumes, Jonah's other operating revenues decreased $0.1 million primarily as a result of the deconsolidation of Jonah and other miscellaneous operating revenues decreased $0.2 million. These decreases were offset by a $0.6 million increase on the Panola and Chaparral Pipelines primarily resulting from new pipeline capacity leases.

Costs and expenses (excluding purchases of petroleum products) decreased $3.3 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005. Depreciation and amortization expense decreased $2.4 million primarily due to a $2.7 million decrease on Jonah as a result of its deconsolidation and a $0.5 million decrease in amortization expense on Val Verde as a result of lower volumes on contracts included in the intangible assets, partially offset by a $0.5 million increase in amortization expense on Val Verde's intangible assets as a result of a decrease in the estimated life of intangible assets under the units-of-production method in the 2006 period which increased amortization expense and a $0.2 million increase on Val

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Verde primarily due to accretion expense on conditional asset retirement obligations (as discussed below). Based on the reduction in some producers' limited production estimates in the third quarter of 2006, we revised the units-of-production calculation for Val Verde's gathering agreements intangible assets, which increased amortization expense in the Midstream Segment by approximately $0.2 million per month (see Note 2 in the Notes to the Consolidated Financial Statements). This reduction in future production forecasts could reduce future revenues on certain gathering contracts of the Val Verde system. Further revisions to these estimates may occur as additional production information is made available to us. Operating expenses decreased $0.9 million primarily due to a $2.9 million decrease relating to the deconsolidation of Jonah, partially offset by a $1.4 million increase related to imbalance valuations and a $0.7 million increase in other pipeline operating and maintenance expense. Taxes – other than income taxes decreased $0.2 million due to actual property taxes being lower than previously estimated, partially offset by a higher property asset base in the 2006 period. General and administrative expenses decreased $0.1 million primarily due to a decrease in consulting and contract services, partially offset by increased expenses relating to our special unitholder meeting to consider EPCO's proposals to amend our Partnership Agreement and issue Units to our General Partner, as well as other proposals. Operating fuel and power increased $0.3 million primarily due to higher transportation volumes and power rates.

Equity earnings of $11.6 million were from our ownership interest in the Jonah joint venture with an affiliate of Enterprise, which was formed effective August 1, 2006. Beginning August 1, 2006, revenues and costs and expenses of Jonah have been included in equity earnings based upon our ownership interest in Jonah. Prior to August 1, 2006, Jonah was wholly-owned, and its revenues and costs and expenses were included in the individual revenues and costs and expenses line items. For the period from August 1, 2006 through September 30, 2006, our sharing in the revenues and costs and expenses of Jonah was 100%. If the revenues and costs and expenses from Jonah for the three months ended September 30, 2006 and 2005, had been accounted for under the same method in both periods, operating results from Jonah would have increased $3.8 million in the 2006 period, compared with the prior year period, primarily due to increased volumes generated from completion of Phase IV of the Jonah expansion project.

Other income – net increased $0.4 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2006, due to higher interest income earned on cash investments and other investing activities.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Revenues from the gathering of natural gas decreased $4.5 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Natural gas gathering revenues from the Jonah system decreased $14.3 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $10.4 million primarily due to the Phase IV expansion of the Jonah system completed in February 2006, prior to deconsolidation. Jonah's gathering volumes averaged 1.2 Bcf per day for the nine months ended September 30, 2006, compared with 1.1 Bcf per day for the nine months ended September 30, 2005. Jonah's average natural gas gathering rate per MMBtu increased 10% primarily due to lower system wellhead pressures. Jonah's volumes gathered increased 36.4 Bcf primarily as a result of the Phase IV expansion for the nine months ended September 30, 2006, compared to the nine months ended September 30, 2005. Natural gas gathering revenues from the Val Verde system decreased $0.6 million for the nine months ended September 30, 2006, primarily due to the natural decline of coal bed methane production. Val Verde's volumes gathered increased 5.6 Bcf primarily due to increased volumes from a natural gas connection on the Val Verde system. Val Verde's average natural gas gathering rate per MMBtu decreased 6% primarily due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

Sales from petroleum products relating to the natural gas marketing activities were $18.8 million and purchases of petroleum products were $17.3 million for the period from January 1, 2006, through July 31, 2006. Effective August 1, 2006, with the deconsolidation of Jonah, sales and purchases of natural gas are reported in equity earnings.

Revenues from the transportation of NGLs decreased $1.1 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, due to a decrease in the average NGL transportation rate per barrel as a result of increased short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox Pipeline.

Other operating revenues increased $1.9 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Other operating revenues increased $1.1 million on the Panola Pipeline and $0.8 million on the Chaparral Pipeline primarily due to new pipeline capacity leases. Other operating revenues on Jonah increased $0.7 million primarily due to higher condensate sales. These increases were partially offset by a $0.5 million decrease on Val Verde primarily due to a decrease in volumes.

Costs and expenses (excluding purchases of petroleum products) increased $13.1 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. Operating expenses increased $7.5 million primarily due to a $3.8 million increase related to imbalance valuations, a $3.0 million increase in expense as a result of the migration to a shared services environment with EPCO and a $0.5 million increase in other pipeline operating and maintenance expense. Depreciation and amortization expense increased $2.6 million primarily due to a $2.9 million increase in amortization expense on Val Verde as a result of a decrease in the estimated life of intangible assets under the units-of-production method which increased amortization expense, a $1.5 million increase in depreciation expense on Jonah as a result of assets placed into service from the Phase IV expansion, a $0.4 million increase on the NGL pipelines as a result of assets placed into service and a $0.2 million increase on Val Verde due to accretion expense on conditional asset retirement obligations (as discussed below), partially offset by a $1.2 million decrease in amortization expense due to the deconsolidation of Jonah and a $1.0 million decrease in amortization expense on Val Verde as a result of lower volumes on contracts included in the intangible assets in the 2006 period. General and administrative expenses increased $2.0 million primarily due to an increase in consulting and contract services and supplies expense and $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO. Operating fuel and power increased $1.5 million primarily due to higher transportation volumes and power rates. Taxes – other than income taxes increased $0.6 million due to actual property taxes being higher than previously estimated and a higher property asset base in the 2006 period. During the nine months ended September 30, 2006 and 2005, gains of $1.4 million and $0.4 million, respectively, were recognized on the sales of various equipment at Val Verde.

Equity earnings of $11.6 million were from our ownership interest in the Jonah joint venture with an affiliate of Enterprise, which was formed effective August 1, 2006. Beginning August 1, 2006, revenues and costs and expenses of Jonah are now included in equity earnings based upon our ownership interest in Jonah. Prior to August 1, 2006, Jonah was wholly-owned, and its revenues and costs and expenses were included in the individual revenues and costs and expenses line items. For the period from August 1, 2006 through September 30, 2006, our sharing in the revenues and costs and expenses of Jonah was 100%. If the revenues and costs and expenses from Jonah for the nine months ended September 30, 2006 and 2005, had been accounted for under the same method in both periods, operating results from Jonah would have increased $25.2 million in the 2006 period, compared with the prior year period, primarily due to increased volumes generated from completion of Phase IV of the Jonah expansion project.

Other income – net increased $0.4 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2006, due to higher interest income earned on cash investments and other investing activities.

Asset Retirement Obligations

During the third quarter of 2006, we recorded $0.3 million of expense included in depreciation and amortization expense, related to conditional asset retirement obligations. Additionally, we have recorded a $0.7

million liability, which represents the fair value, of the conditional asset retirement obligations related to the retirement of our Val Verde gathering system. During the third quarter of 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded asset retirement obligations.

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 recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner and a fairness opinion was rendered by an independent third-party. The sales proceeds were 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 were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months and nine months ended September 30, 2006 and 2005, are presented below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Sales of petroleum products	$ —	$ 2,880	$ 3,828	$ 7,337
Other	—	789	932	2,141
Total operating revenues	—	3,669	4,760	9,478
Purchases of petroleum products	—	2,585	3,000	5,761
Operating expense	—	205	182	501
Depreciation and amortization	—	153	51	459
Taxes – other than income taxes	—	34	30	95
Total costs and expenses	—	2,977	3,263	6,816
Income from discontinued operations	$ —	$ 692	$ 1,497	$ 2,662

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Jonah Pioneer plant decreased $0.7 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to the sale of the Pioneer plant on March 31, 2006, partially offset by 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

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

Interest expense increased $2.9 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, primarily due to higher short term floating interest rates on our revolving credit facility, partially offset by lower outstanding borrowings during the 2006 period.

Capitalized interest decreased $0.6 million for the three months ended September 30, 2006, compared with the three months ended September 30, 2005, due to lower construction work-in-progress balances in 2006 as compared to the 2005 period.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Interest expense increased $6.4 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility, partially offset by reductions in interest expense of $2.5 million during 2006 related to our interest rate swaps and $2.0 million of increased interest expense in the 2005 period related to the termination of a treasury lock (see Note 3 in the Notes to the Consolidated Financial Statements).

Capitalized interest increased $3.6 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period.

Deferred Income Tax Expense – Texas Margin Tax

In May 2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaces its existing franchise tax. In general, legal entities that do business in Texas are subject to the Texas Margin Tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the state of Texas changed from nontaxable to taxable. The Texas Margin Tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Our deferred income tax expense for state taxes relates only to Texas Margin Tax obligations. The Texas Margin Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation. The deferred tax liability shown on our consolidated balance sheet reflects the net tax effect of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is classified as noncurrent. The Texas Margin Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of at least 80% is owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together.

Since the Texas Margin Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, we determined the Texas Margin Tax should be accounted for as an income tax in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*. The base used to compute the Texas Margin Tax affects book-tax differences. All effects of a tax law change are accounted for in the period of the law's enactment. A change in tax status that results from a change in tax law is recognized on the enactment date and the effect of recognizing a

deferred tax liability or asset is included in income from continuing operations. Therefore, we have calculated and recorded an estimated deferred tax liability of approximately $0.7 million using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax liability is expected to be realized or settled. The non-cash offsetting charge is shown on our unaudited consolidated statements of income as deferred income tax expense for the nine months ended September 30, 2006.

The constitutionality of the Texas Margin Tax is being questioned. The Texas Comptroller has requested a formal opinion from the Texas Attorney General on whether the Texas Margin Tax is an impermissible income tax that violates the Texas constitution. The Texas constitution requires voter approval of any tax imposed on the net income of natural persons, including a person's share of partnership unincorporated association income; such approval was not obtained for the Texas Margin Tax. The Comptroller has requested that the Attorney General determine whether the direct imposition of the Texas Margin Tax on partnerships without voter approval violates this constitutional requirement. The Attorney General's decision is not expected until late 2006 or early 2007. If the Texas Margin Tax is ultimately challenged in court, the legislation enacting the Texas Margin Tax gives the Texas Supreme Court jurisdiction over the constitutional challenge and allows the Court to grant injunctive or declaratory relief. The Court would have 120 days from the date the challenge is filed to make a ruling.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At September 30, 2006, and December 31, 2005, we had working capital deficits of $69.7 million and $38.1 million, respectively. At September 30, 2006, we had approximately $330.9 million in available borrowing capacity under our revolving credit facility to cover any working capital needs. Cash flows for the nine months ended September 30, 2006 and 2005 were as follows (in millions):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Cash provided by (used in):		
Operating activities	$ 232.5	$ 49.1
Investing activities	(174.6)	(267.5)
Financing activities	(58.0)	202.1

Operating Activities

Net cash from operating activities for the nine months ended September 30, 2006 and 2005, was comprised of the following (in millions):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net income	$ 145.5	$ 117.9
Income from discontinued operations	(19.4)	(2.7)
Deferred income tax expense	0.7	—
Depreciation and amortization	83.7	82.6
Earnings in equity investments	(15.2)	(16.6)
Distributions from equity investments	26.5	28.2
Gains on sales of assets	(1.4)	(0.6)
Non-cash portion of interest expense	1.2	1.2
Cash provided by (used in) working capital and other	9.4	(164.0)
Net cash provided by continuing operating activities	231.0	46.0
Cash flows from discontinued operations	1.5	3.1
Net cash from operating activities	$ 232.5	$ 49.1

Net cash provided by operating activities increased $183.4 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005, primarily due to a decrease of $108.2 million in crude oil inventory (as discussed below) and due to the timing of cash disbursements and cash receipts for other working capital components, partially offset by a decrease of $1.7 million in distributions received from our equity investments in Seaway and MB Storage. 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.

Crude oil inventory decreased $108.2 million for the nine months ended September 30, 2006, compared with the nine months ended September 30, 2005. During the second and third quarters of 2005, we purchased crude oil and simultaneously entered into offsetting sales contracts for physical delivery during the fourth quarter of 2005. The purpose of these contracts was to lock in a margin on the crude oil while it was stored in our facilities. These purchases of crude oil had a negative impact on cash from operating activities (as discussed above) until the crude oil was delivered and payment was received from customers.

Net cash from operating activities for the nine months ended September 30, 2006 and 2005, included interest payments, net of amounts capitalized, of $84.4 million and $78.5 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 make these interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $174.6 million for the nine months ended September 30, 2006, and were comprised of $125.7 million of capital expenditures, $65.4 million of cash contributions for our ownership interest in the Jonah joint venture with Enterprise for capital expenditures on its Phase V expansion, $11.0 million for the acquisition of Downstream Segment assets, $5.6 million of cash paid for linefill on assets owned, $4.2 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures and $2.5 million of cash contributions for TE Products' ownership interest in Centennial for operating needs, partially offset by $39.8 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 on March 31, 2006. Cash flows used in investing activities totaled $267.5 million for the nine months ended September 30, 2005, and were comprised of $148.1 million of capital expenditures, $68.9 million for the acquisition of Downstream Segment assets, $43.3 million for the acquisition of Upstream Segment assets, $5.1 million of cash paid for linefill on assets owned and $2.6 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures, 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 $58.0 million for the nine months ended September 30, 2006, and were comprised of $206.2 million of distributions paid to unitholders and $46.9 million in repayments, net of borrowings, on our revolving credit facility, partially offset by $195.1 million of net proceeds received from the public issuance of 5.8 million Units in July 2006. Cash flows provided by financing activities totaled $202.1 million for the nine months ended September 30, 2005, and were comprised of $278.8 million of net proceeds received from the public issuance of 7.0 million Units in May and June 2005 and $107.5 million in borrowings, net of repayments, on our revolving credit facility, partially offset by $184.2 million of distributions paid to unitholders.

We paid cash distributions of $206.2 million ($2.025 per Unit) and $184.2 million ($2.00 per Unit) during each of the nine months ended September 30, 2006 and 2005, respectively. Additionally, we declared a cash distribution of $0.675 per Unit for the quarter ended September 30, 2006. We paid the distribution of $72.4 million on November 7, 2006, to unitholders of record on October 31, 2006.

In July 2006, we issued and sold in an underwritten public offering 5.0 million Units at a price to the public of $35.50 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $170.4 million. On July 12, 2006, 750,000 additional Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. Proceeds from the over-allotment sale, net of underwriting discount, totaled $25.6 million. The net proceeds from the offering and the over-allotment were used to reduce indebtedness under our Revolving Credit Facility.

Other Considerations

Universal Shelf

We have filed with the Securities and Exchange Commission 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. Taking into account our May 2005 and July 2006 equity offerings, in which we issued $290.8 million and $204.1 million of equity securities, respectively, we had approximately $1.5 billion remaining under this shelf registration, subject to customary marketing terms and conditions.

Credit Facilities

We have in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matures on December 13, 2011. 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 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 10 in the Notes to the Consolidated Financial Statements), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets.

On July 31, 2006, we amended our Revolving Credit Facility. The primary revisions were as follows:

- The maturity date of the credit facility was extended from December 13, 2010 to December 13, 2011. 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 releases Jonah as a guarantor of the Revolving Credit Facility and restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other third-party debt in the principal aggregate amount of $50.0 million.
- The amendment modifies the financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility) pro forma adjustments for material capital projects.
- The amendment allows for the issuance of Hybrid Securities (as defined in the Revolving Credit Facility) of up to 15% of our Consolidated Total Capitalization (as defined in the Revolving Credit Facility).

At September 30, 2006, $359.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 6.02%. At September 30, 2006, we were in compliance with the covenants of this credit facility.

During October 2006, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $200.0 million. These agreements, which are derivative instruments, hedge our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.7%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2006 will be approximately $195.0 million (including $9.0 million of capitalized interest). We expect to spend approximately $133.0 million for revenue generating projects. We expect to spend approximately $35.0 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 $27.0 million to improve operational efficiencies and reduce costs among all of our business segments. These estimates are lower than previously reported amounts primarily due to timing delays of construction projects. Additionally, amounts related to Jonah capital expenditures will be reported as joint venture contributions due to the deconsolidation of Jonah on August 1, 2006.

During 2006, TE Products may be required to contribute additional 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.

Additionally, we expect to contribute approximately $125.0 million to our Jonah joint venture for the construction of the Phase V expansion during 2006, of which $65.0 million has already been paid. We expect to contribute approximately an additional $10.0 million to our Jonah joint venture for other capital expenditures during the remainder of 2006. In August 2006, we entered into an amended and restated general partnership agreement forming a joint venture to expand our Jonah system with an affiliate of Enterprise. 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 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 catastrophic 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 September 30, 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 Petroleum Company LLC ("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 September 30, 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 $4.4 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, depending upon the nature of the catastrophic event.

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 September 30, 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, due 2011	$ 359.0	$ —	$ —	$ —	$ 359.0
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)	758.4	99.4	181.3	175.5	302.2
Debt and interest subtotal	2,207.4	99.4	361.3	175.5	1,571.2
Operating leases (4)	72.4	18.5	22.7	13.5	17.7
Contributions to Jonah (5)	242.0	242.0	—	—	—
Contributions to Centennial (6)	8.6	8.6	—	—	—
Capital expenditure obligations (7)	4.2	4.2	—	—	—

Standby letter of credit (8)	10.1	10.1	—	—	—
Other liabilities and deferred credits (9)	8.0	—	6.3	0.3	1.4
Total	$ 2,552.7	$ 382.8	$ 390.3	$ 189.3	$ 1,590.3

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(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 September 30, 2006, the 7.51% Senior Notes include an adjustment to decrease the fair value of the debt by $3.9 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 September 30, 2006, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $29.1 million. At September 30, 2006, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.1 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 nine months ended September 30, 2006, TE Products exceeded the minimum throughput requirements on the lease agreement.

(5) Expected contributions to Jonah for our share of the Phase V expansion. Of this amount, we expect to contribute approximately $125.0 million during the remainder of 2006 and $117.0 million in 2007.

(6) Expected contribution to Centennial during 2007 for an obligation of Centennial related to the formation of Centennial Pipeline LLC in 2001.

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

(8) At September 30, 2006, we had outstanding a $10.1 million standby letter of credit in connection with crude oil purchased during the third quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the fourth quarter of 2006.

(9) Excludes approximately $9.5 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $4.2 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 nine months ended September 30, 2006, crude oil purchases averaged approximately $781.4 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

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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 September 30, 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 September 30, 2006, was a gain of $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 $0.3 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 September 30, 2006, we had $359.0 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. On January 20, 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. 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. In the third quarter of 2006, these swaps were designated as cash flow hedges. For the period from January 20, 2006 through the date these swaps were designated as cash flow hedges, changes in the fair value of the swaps were recognized in earnings, which resulted in a $2.2 million reduction to interest expense. While these interest rate swaps remain in effect, future changes in the fair value of the cash flow hedges, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings. At September 30, 2006, the fair value of these interest rate swaps was $1.5 million. Utilizing the balances of our variable interest rate debt outstanding at September 30, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense related to our revolving credit facility would be $2.4 million.

The following table summarizes the estimated fair values of the Senior Notes as of September 30, 2006 and December 31, 2005 (in millions):

		Fair Value	
	Face Value	September 30, 2006	December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 182.2	$ 183.7
7.625% Senior Notes, due February 2012	500.0	536.1	552.0
6.125% Senior Notes, due February 2013	200.0	200.7	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	222.6	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 nine months ended September 30, 2006, and 2005, we recognized reductions in interest expense of $1.5 million and $4.6 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 September 30, 2006 and 2005, we reviewed the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair values of this interest rate swap were losses of approximately $3.9 million and $0.9 million at September 30, 2006, and December 31, 2005, respectively. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at September 30, 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 September 30, 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

During 2006, we commenced a project to replace or upgrade our general ledger and consolidation software. The implementation is expected to occur in the first quarter of 2007. The project is not in response to any identified deficiency or weakness in our internal control over financial reporting. Other than these proposed changes, there has been no change in our internal control over financial reporting during the third quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our General Partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Report.

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 14 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 the risk factors set forth below and in our Quarterly Report on Form 10-Q for the period ended June 30, 2006, in addition to other information in our Annual Report on Form 10-K for the year ended December 31, 2005, our Current Report on Form 8-K filed on June 16, 2006 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.

The success of our Jonah gas gathering operations is substantially dependent upon Enterprise.

We own our interest in the Jonah gas gathering system, which represents a significant component of our Midstream Segment and its potential for future growth, through a joint venture with Enterprise. The joint venture is governed by a management committee comprised of two representatives approved by an Enterprise affiliate and two representatives approved by subsidiaries of ours. We expect to ultimately own an 80% interest in the joint venture, with Enterprise's affiliate owning the remaining 20%. However, each representative on the management committee

is entitled to one vote, and the joint venture agreement generally requires the affirmative vote of a majority of the members of the management committee to approve an action. Moreover, Enterprise is responsible for managing construction of the Phase V expansion of the system, for half of the costs of the project and for operating the joint venture. We and Enterprise may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in our best interests. Further, Enterprise may experience unanticipated delays or costs in construction or operation of the project, which could require additional capital contributions by us and Enterprise or diminish expected benefits from the project. Any of these factors could materially and adversely affect our results of operations, financial condition and prospects.

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).

3.3	Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 31, 2000 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.4	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 22, 2005 (Filed as Exhibit 3.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.5	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated June 15, 2006, but effective as of February 24, 2005 (Filed as Exhibit 3.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on June 16, 2006.
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).
4.8*	Full Release of Guarantee dated as of July 31, 2006 by Wachovia Bank, National Association, as trustee, in favor of Jonah Gas Gathering Company.
10.1	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed August 3, 2006 and incorporated herein by reference).
10.2	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed August 3, 2006 and incorporated herein by reference).
10.3	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC filed August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.4	Transaction Agreement by and between TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC dated as of September 5, 2006 (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed September 12, 2006 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.

* Filed herewith.
** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.
+ A management contract or compensation plan or arrangement.

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: November 7, 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: November 7, 2006

FULL RELEASE OF GUARANTEE

THIS FULL RELEASE OF GUARANTEE (this "Release") is dated as of July 31, 2006, by Wachovia Bank, National Association (formerly known as First Union National Bank), a national banking association, as trustee under the Indenture referred to below (in such capacity, the "Trustee") in favor of Jonah Gas Gathering Company, a Wyoming general partnership ("Jonah Gas").

RECITALS:

WHEREAS, TEPPCO Partners, L.P., a Delaware limited partnership (the "Partnership"), Jonah Gas and the other subsidiary Guarantors named therein have heretofore executed and delivered to the Trustee an Indenture dated as of February 20, 2002 (as amended, supplemented, or otherwise modified from time to time, the "Indenture"), providing for the Partnership's issuance, from time to time, of its Debt Securities in one or more series unlimited as to principal amount, and the guarantee by each of the Subsidiary Guarantors of the Debt Securities issued pursuant thereto; and

WHEREAS, Section 14.04 of the Indenture provides that the Guarantee of a Subsidiary Guarantor shall be unconditionally released and discharged, upon the release or discharge of all guarantees by such Subsidiary Guarantor of any Debt of the Partnership, other than obligations arising under the Indenture and any Debt Securities issued thereunder, following delivery of a written notice of such release or discharged by the Partnership to the Trustee, except a discharge or release by or as a result of payment under such guarantees; and

WHEREAS, Jonah Gas has guaranteed the obligations of the Partnership under that certain Amended and Restated Credit Agreement, dated as of October 21, 2004, as amended (the "Credit Agreement"), but Jonah Gas has not guaranteed any other Debt of the Partnership; and

WHEREAS, pursuant to a full Release of Guaranty Obligations entered into on July 31, 2006 in favor of Jonah Gas, attached hereto as Exhibit A, Jonah Gas has been released and discharged of its guarantee obligation under the Credit Agreement; and

WHEREAS, the Partnership has requested that Jonah Gas be released as a Subsidiary Guarantor under the Indenture, including all indentures supplemental thereto and in accordance with Section 14.04 of the Indenture, the Partnership has delivered or caused to be delivered to the Trustee an Officers' Certificate and Opinion of Counsel in respect of its request.

NOW, THEREFORE, for good and valuable consideration, the sufficiency and receipt of all of which are acknowledged, the Trustee hereby fully releases and discharges Jonah Gas from all present and future obligations which currently exist or may exist in the future under or in connection with the Indenture, including all indentures supplemental thereto and all Debt Securities issued thereunder. Notwithstanding the ongoing, this is a release of Jonah Gas only, and nothing in this Release shall be construed to be a release of any other subsidiary Guarantor or any obligations of the Partnership in connection with the Indenture.

THIS RELEASE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

IN WITNESS WHEREOF, the Trustee has caused this Release to be duly executed and delivered by a duly authorized officer as of the date first above written.

WACHOVIA BANK, NATIONAL ASSOCIATION,
As Trustee

By: /s/ RONDA L. PARMAN
Name: Ronda L. Parman
Title: Vice President

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2002	2003	2004	2005	Nine Months Ended September 30, 2006
			(in thousands)		
Earnings					
Income From Continuing Operations *	105,882	104,958	112,658	138,639	109,474
Fixed Charges	73,381	93,294	80,695	93,414	75,322
Distributed Income of					
Equity Investment	30,938	28,003	47,213	37,085	26,546
Capitalized Interest	(4,345)	(5,290)	(4,227)	(6,759)	(8,120)
Total Earnings	205,856	220,965	236,339	262,379	203,222
Fixed Charges					
Interest Expense	66,192	84,250	72,053	81,861	63,522
Capitalized Interest	4,345	5,290	4,227	6,759	8,120
Rental Interest Factor	2,844	3,754	4,415	4,794	3,680
Total Fixed Charges	73,381	93,294	80,695	93,414	75,322
Ratio: Earnings / Fixed Charges	2.81	2.37	2.93	2.81	2.70

* Excludes discontinued operations, 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.

November 7, 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.

November 7, 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 September 30, 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

November 7, 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.

Exhibit 32.2

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 September 30, 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

November 7, 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.