ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
August 08, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended June 30, 2006

OR

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

For the transition period from __________ to __________.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)
(713) 381-6500
(Registrant s Telephone Number, Including Area Code)
2727 North Loop West
Houston, Texas 77008-1044
(Former Address)

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 þ 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.

Large accelerated filer þ 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 þ

There were 416,698,972 common units of *Enterprise Products Partners L.P.* outstanding at July 31, 2006. These common units trade on the New York Stock Exchange under the ticker symbol EPD.

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PART I. FINANCIAL INFORMATION.

Item 1. ***Financial Statements*.**

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 24,524	$ 42,098
Restricted cash	21,655	14,952
Accounts and notes receivable trade, net of allowance for doubtful accounts of $20,121 at June 30, 2006 and $25,849 at December 31, 2005	1,324,611	1,448,026
Accounts receivable related parties	12,691	6,557
Inventories	451,237	339,606
Prepaid and other current assets	169,276	120,208
Total current assets	2,003,994	1,971,447
Property, plant and equipment, net	9,018,275	8,689,024
Investments in and advances to unconsolidated affiliates	464,605	471,921
Intangible assets, net of accumulated amortization of $205,055 at June 30, 2006 and $163,121 at December 31, 2005	909,323	913,626
Goodwill	493,995	494,033
Deferred tax asset	3,444	3,606
Other assets	150,104	47,359
Total assets	$13,043,740	$12,591,016
LIABILITIES AND PARTNERS EQUITY		
Current liabilities		
Accounts payable trade	$ 264,368	$ 265,699
Accounts payable related parties	37,597	23,367
Accrued gas payables	1,392,239	1,372,837
Accrued expenses	30,160	30,294
Accrued interest	69,945	71,193
Other current liabilities	188,021	126,881
Total current liabilities	1,982,330	1,890,271
Long-term debt	4,821,401	4,833,781
Other long-term liabilities	131,201	84,486
Minority interest	120,744	103,169
Commitments and contingencies		
Partners equity		
Limited partners		
Common units (408,508,111 units outstanding at June 30, 2006 and 389,109,564 units outstanding at December 31, 2005)	5,851,032	5,542,700
	6,580	18,638

Restricted common units (1,075,017 units outstanding at June 30, 2006 and 751,604 units outstanding at December 31, 2005)		
General partner	119,535	113,496
Accumulated other comprehensive income	10,917	19,072
Deferred compensation		(14,597)
Total partners equity	5,988,064	5,679,309
Total liabilities and partners equity	$13,043,740	$12,591,016

See Notes to Unaudited Condensed Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
AND COMPREHENSIVE INCOME
(Dollars in thousands, except per unit amounts)

	For the Three Months Ended June 30, 2006	For the Three Months Ended June 30, 2005	For the Six Months Ended June 30, 2006	For the Six Months Ended June 30, 2005
REVENUES				
Third parties	$3,404,419	$2,590,820	$6,564,418	$5,088,149
Related parties	113,434	80,948	203,509	139,141
Total	3,517,853	2,671,768	6,767,927	5,227,290
COST AND EXPENSES				
Operating costs and expenses				
Third parties	3,244,576	2,461,244	6,189,796	4,779,317
Related parties	79,009	68,889	180,652	134,460
Total operating costs and expenses	3,323,585	2,530,133	6,370,448	4,913,777
General and administrative costs				
Third parties	5,405	7,591	8,137	12,609
Related parties	10,830	11,119	21,838	20,794
Total general and administrative costs	16,235	18,710	29,975	33,403
Total costs and expenses	3,339,820	2,548,843	6,400,423	4,947,180
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	8,012	2,581	12,041	10,860
OPERATING INCOME	186,045	125,506	379,545	290,970
OTHER INCOME (EXPENSE)				
Interest expense	(56,333)	(56,746)	(114,410)	(110,159)
Other, net	3,393	1,245	5,362	2,164
Other expense	(52,940)	(55,501)	(109,048)	(107,995)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE	133,105	70,005	270,497	182,975
Provision for income taxes	(6,272)	1,034	(9,164)	(735)
INCOME BEFORE MINORITY INTEREST AND CHANGE IN	126,833	71,039	261,333	182,240

ACCOUNTING PRINCIPLE				
Minority interest	(538)	(380)	(2,736)	(2,325)
INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE	126,295	70,659	258,597	179,915
Cumulative effect of change in accounting principle (see Note 3)			1,475	
NET INCOME	$ 126,295	$ 70,659	$ 260,072	$ 179,915
Cash flow financing hedges (see Note 4)	1,638		1,638	
Amortization of cash flow financing hedges	(1,052)	(1,006)	(2,093)	(2,001)
Change in fair value of commodity hedges	(7,951)		(7,700)	(1,434)
COMPREHENSIVE INCOME	$ 118,930	$ 69,653	$ 251,917	$ 176,480
ALLOCATION OF NET INCOME:				
Limited partners interest in net income	$ 103,192	$ 54,040	$ 215,561	$ 147,763
General partner interest in net income	$ 23,103	$ 16,619	$ 44,511	$ 32,152
EARNINGS PER UNIT: (see Note 14)				
Basic income per unit before change in accounting principle	$ 0.25	$ 0.14	$ 0.53	$ 0.39
Basic income per unit	$ 0.25	$ 0.14	$ 0.54	$ 0.39
Diluted income per unit before change in accounting principle	$ 0.25	$ 0.14	$ 0.53	$ 0.39
Diluted income per unit	$ 0.25	$ 0.14	$ 0.54	$ 0.39

See Notes to Unaudited Condensed Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For the Six Months Ended June,	
	2006	2005
OPERATING ACTIVITIES		
Net income	$ 260,072	$ 179,915
Adjustments to reconcile net income to cash flows provided from operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	212,768	201,013
Depreciation and amortization in general and administrative costs	3,752	3,490
Amortization in interest expense	487	(370)
Equity in income of unconsolidated affiliates	(12,041)	(10,860)
Distributions received from unconsolidated affiliates	20,348	38,908
Cumulative effect of change in accounting principle	(1,475)	
Operating lease expense paid by EPCO, Inc.	1,056	1,056
Minority interest	2,736	2,325
Gain on sale of assets	(197)	(5,353)
Deferred income tax expense	9,180	3,875
Changes in fair market value of financial instruments	(53)	111
Net effect of changes in operating accounts (see Note 17)	74,692	(296,273)
Net cash provided from operating activities	571,325	117,837
INVESTING ACTIVITIES		
Capital expenditures	(575,419)	(435,769)
Contributions in aid of construction costs	34,941	27,032
Proceeds from sale of assets	256	42,267
Decrease (increase) in restricted cash	(6,703)	13,130
Cash used for business combinations and asset purchases	(38,100)	(181,079)
Acquisition of intangible asset		(1,750)
Advances to Jonah affiliate (see Note 13)	(97,767)	
Investments in unconsolidated affiliates	(14,115)	(80,650)
Advances (to) from unconsolidated affiliates	7,120	(1,130)
Return of investment of unconsolidated affiliate		47,500
Cash used in investing activities	(689,787)	(570,449)
FINANCING ACTIVITIES		
Borrowings under debt agreements	1,435,000	2,612,345
Repayments of debt	(1,402,000)	(2,341,007)
Debt issuance costs		(8,287)
Distributions paid to partners	(400,474)	(346,571)
Distributions paid to minority interests	(4,131)	(4,154)
Contributions from minority interests	19,018	23,564
Contribution from general partner related to issuance of restricted units		7

Net proceeds from issuance of common units	453,475	525,204
Cash provided by financing activities	100,888	461,101
NET CHANGE IN CASH AND CASH EQUIVALENTS	(17,574)	8,489
CASH AND CASH EQUIVALENTS, JANUARY 1	42,098	24,556
CASH AND CASH EQUIVALENTS, JUNE 30	$ 24,524	$ 33,045

See Notes to Unaudited Condensed Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS EQUITY
(See Note 11 for Unit History and Detail of Changes in Limited Partners Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Deferred Compensation	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2005	$5,561,338	$113,496	$(14,597)	$ 19,072	$5,679,309
Net income	215,561	44,511			260,072
Operating leases paid by EPCO, Inc.	1,035	21			1,056
Cash distributions to partners	(352,445)	(47,304)			(399,749)
Unit option reimbursements to EPCO, Inc.	(710)	(15)			(725)
Net proceeds from sales of common units	442,832	9,038			451,870
Proceeds from exercise of unit options	1,573	32			1,605
Change in accounting method for equity awards (see Note 3)	(15,814)	(322)	14,597		(1,539)
Amortization of equity awards	4,242	78			4,320
Change in fair value of commodity hedges				(7,700)	(7,700)
Interest rate hedging financial instruments recorded as cash flow hedges:					
- Change in fair value				1,638	1,638
- Amortization of gain as component of interest expense				(2,093)	(2,093)
Balance, June 30, 2006	$5,857,612	$119,535	**$**	$ 10,917	$5,988,064

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Partnership Organization and Basis of Financial Statement Presentation

Partnership Organization and Formation

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD. Unless the context requires otherwise, references to we, us, our, or Enterprise Products Partners are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids (NGLs) related businesses of EPCO, Inc. (EPCO). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our Operating Partnership). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol EPE. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (EPE Holdings), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

References to TEPPCO mean TEPPCO Partners, L.P., a publicly traded Delaware limited partnership, which is an affiliate of us. References to TEPPCO GP refer to the general partner of TEPPCO, which is wholly owned by a private company subsidiary of EPCO.

Basis of Presentation of Consolidated Financial Statements

Our results of operations for the three and six months ended June 30, 2006 are not necessarily indicative of results expected for the full year.

Except per unit amounts, or as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Essentially all of our assets, liabilities, revenues and expenses are recorded at the Operating Partnership level in our consolidated financial statements. We act as guarantor of certain of our Operating Partnership s debt obligations. See Note 18 for condensed consolidated financial information of our Operating Partnership.

In our opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe our disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with generally accepted accounting principles in the United States of America (GAAP) have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (SEC or Commission). These unaudited financial statements should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2005 (Commission File No. 1-14323).

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2. General Accounting Policies and Related Matters

Use of estimates

In accordance with GAAP, we use estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. Our actual results could differ from these estimates.

New accounting pronouncements

Emerging Issues Task Force (EITF) 04-13, Accounting for Purchases and Sale of Inventory With the Same Counterparty. This accounting guidance requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. This guidance was effective April 1, 2006, and our adoption of this guidance had no impact on our financial position, results of operations or cash flows.

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). This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. This guidance specifically applies to taxes imposed by governmental authorities on revenue-producing transactions between sellers and customers (gross receipts taxes are excluded). This guidance is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis.

Statement of Financial Accounting Standards (SFAS) 155, Accounting for Certain Hybrid Financial Instruments. This accounting standard amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, and resolves issues addressed in Statement 133 Implementation Issue D1, *Application of Statement 133 to Beneficial Interests to Securitized Financial Assets*. A hybrid financial instrument is one that embodies both an embedded derivative and a host contract. For certain hybrid financial instruments, SFAS 133 requires an embedded derivative instrument be separated from the host contract and accounted for as a separate derivative instrument. SFAS 155 amends SFAS 133 to provide a fair value measurement alternative for certain hybrid financial instruments that contain an embedded derivative that would otherwise be recognized as a derivative separately from the host contract. For hybrid financial instruments within its scope, SFAS 155 allows the holder of the instrument to make a one-time, irrevocable election to initially and subsequently measure the instrument in its entirety at fair value instead of separately accounting for the embedded derivative and host contract. We are evaluating the effect of this recent guidance, which is effective January 1, 2007 for our partnership.

Change in accounting principle and reclassifications

In January 2006, we adopted the provisions of SFAS 123(R), *Share-Based Payment.* Upon adoption of this accounting standard, we recognized a cumulative effect of change in accounting principle of $1.5 million (a benefit). For additional information regarding our adoption of SFAS 123(R), see Note 3.

Accounting for employee benefit plans

Dixie Pipeline Company (Dixie), a consolidated subsidiary, directly employs the personnel operating its pipeline system. Certain of these employees are eligible to participate in Dixie s defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie s employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined contribution plan. Dixie contributed $0.1 million to its company-sponsored defined contribution plan during the three months ended June 30, 2006 and 2005. During the six months ended June 30, 2006 and 2005, Dixie contributed $0.2 million and $0.1 million to its company-sponsored defined contribution plan, respectively.

Pension and postretirement benefit plans. Dixie s net pension benefit costs were $0.2 million for the three months ended June 30, 2006 and 2005. For the six months ended June 30, 2006 and 2005, Dixie s net pension benefit costs were $0.3 million and $0.2 million, respectively. Dixie s net postretirement benefit costs were $0.1 million for the three months ended June 30, 2006 and 2005. For the six months ended June 30, 2006 and 2005, Dixie s net postretirement benefit costs were $0.1 million. During the remainder of 2006, Dixie expects to contribute approximately $0.2 million to its postretirement benefit plan and between $2 million and $4.4 million to its pension plan.

Provision for income taxes

Prior to the second quarter of 2006, our provision for income taxes related to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represented our only consolidated subsidiaries that were historically subject to such income taxes. In May 2006, the State of Texas enacted a new business tax (the Texas Margin Tax) that replaced the existing state 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 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. The Texas Margin Tax becomes effective for margin 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. The taxable margin is the lesser of (1) 70% of total revenue or (2) total revenue less (a) cost of goods sold or (b) compensation and benefits. Our deferred tax liability, which is a component of other long-term liabilities on our consolidated balance sheets, reflects the net tax effects of temporary differences related to items such as property, plant and equipment. Therefore, the deferred tax liability is noncurrent. We have calculated and recorded an estimated deferred tax liability of approximately $6.1 million for the Texas Margin Tax. The non-cash offsetting charge of $6.1 million is shown on our unaudited condensed statements of consolidated operations and comprehensive income as a component of provision for income taxes for the three months and six months ended June 30, 2006.

3. Accounting for Equity Awards

Effective January 1, 2006, we adopted SFAS 123(R) to account for equity awards. Prior to our adoption of SFAS 123(R), we accounted for our equity awards using the intrinsic value method described in Accounting Principles Board Opinion (APB) 25, *Accounting for Stock Issued to Employees.* SFAS 123(R) requires us to recognize compensation expense related to our equity awards based on the fair value of the award at the grant date. The fair value of an equity award is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an award is amortized to earnings on a straight-line basis over the requisite service or vesting period.

Upon our adoption of SFAS 123(R), we recognized a cumulative effect of change in accounting principle of $1.5 million (a benefit) based on SFAS 123(R) s requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to nonvested (or restricted) common units was reversed on January 1, 2006.

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Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit L.P. (the Employee Partnership) and the issuance of nonvested units. The effects of applying SFAS 123(R) during the three and six months ended June 30, 2006 did not have a material effect on our net income or basic and diluted earnings per unit.

Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard. The following table shows the pro forma effects on our earnings for the three and six months ended June 30, 2005 as if the fair value method of SFAS 123, *Accounting for Stock-Based Compensation* had been used instead of the intrinsic-value method of APB 25. The only equity awards outstanding during the three and six months ended June 30, 2005 were unit options and nonvested units.

	For the Three Months Ended June 30, 2005	For the Six Months Ended June 30, 2005
Reported net income	$70,659	$179,915
Additional unit option-based compensation expense estimated using fair value-based method	(177)	(354)
Pro forma net income	$70,482	$179,561
Basic and diluted earnings per unit:		
As reported and pro forma	$ 0.14	$ 0.39

Unit options

Under EPCO s 1998 Long-Term Incentive Plan (the 1998 Plan), non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO s key employees who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

In order to fund its obligations under the 1998 Plan, EPCO purchases common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for our allocable share of the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the options of seven years, (ii) risk-free interest rates ranging from 3.1% to 6.4%, (iii) an expected distribution yield on our common units ranging from 5.3% to 10%, and (iv) expected unit price volatility on our common units ranging from 20% to 30%. In general, our assumption of expected life represents the period of time that options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility for our units is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The information in the following table shows unit option activity under the 1998 Plan.

	Number of Units	Weighted-average strike price	Weighted-average remaining contractual term (in years)	Aggregate Intrinsic Value [(1)]
Outstanding at December 31, 2005	2,082,000	$ 22.16		
Granted	590,000	$ 24.85		
Exercised	(63,000)	$ 14.75		
Forfeited	(45,000)	$ 24.28		
Outstanding at June 30, 2006	2,564,000	$ 22.92	7.91	$3,594
Exercisable at June 30, 2006	714,000	$ 19.87	5.35	$3,594

(1) Aggregate intrinsic value reflects fully vested unit options at June 30, 2006.

The total intrinsic value of unit options exercised during the three and six months ended June 30, 2006 was $0.3 million and $0.6 million, respectively. We recognized $0.2 million and $0.3 million of compensation expense associated with unit options during the three and six months ended June 30, 2006, respectively.

As of June 30, 2006, there was an estimated $1.9 million of total unrecognized compensation cost related to nonvested unit options granted under the 1998 Plan to EPCO employees who work on our behalf. That cost is expected to be recognized over a weighted-average period of 2.8 years.

During the six months ended June 30, 2006, we received cash of $1.6 million from the exercise of unit options, and our option-related reimbursements to EPCO were $0.7 million.

Nonvested units

Under the 1998 Plan, we may issue nonvested (or restricted) common units to key employees of EPCO and directors of our general partner. The 1998 Plan provides for the issuance of 3,000,000 restricted common units, of which 1,933,088 remain authorized for issuance at June 30, 2006.

In general, our restricted unit awards allow recipients to acquire the underlying common units (at no cost to the recipient) once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such nonvested units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of such restricted units is based on (i) the market price of the underlying common units on the date of grant and (ii) an allowance for forfeitures.

The following table summarizes information regarding our restricted units for the six months ended June 30, 2006.

	Number of	Weighted-average grant

	Units	date fair value
Restricted units at December 31, 2005	751,604	$ 24.49
Granted	400,400	$ 24.85
Vested	(39,711)	$ 23.91
Forfeited	(37,276)	$ 24.14
Restricted units at June 30, 2006	1,075,017	$ 24.66

The total fair value of restricted units that vested during the three and six months ended June 30, 2006 was $0.9 million and $1.0 million, respectively. During the three and six months ended June 30, 2006, we recognized $1.6 million and $2.3 million of compensation expense, respectively, associated with nonvested units.

As of June 30, 2006, there was $13.9 million of total unrecognized compensation cost related to nonvested units issued to EPCO employees that work on our behalf. That cost is expected to be recognized over a weighted-average period of 3.1 years.

Employee Partnership

In connection with the initial public offering of Enterprise GP Holdings in August 2005, the Employee Partnership was formed to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. At inception, the Employee Partnership used $51 million in contributions it received from an affiliate of EPCO (which was admitted as the Class A limited partner of the Employee Partnership as a result of such contribution) to purchase 1,821,428 units of Enterprise GP Holdings in August 2005. Certain EPCO employees, including all of EPE Holdings and Enterprise Products GP s executive officers other than Dan L. Duncan, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

As described in its partnership agreement, the Employee Partnership will be liquidated upon the earlier of (i) August 2010 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of the Employee Partnership, units having a fair market value equal to the Class A limited partner s capital base will be distributed to the Class A limited partner, plus any Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners as a residual profits interest in the Employee Partnership as an award.

Prior to our adoption of SFAS 123(R), the estimated value of the profits interest was accounted for in a manner similar to a stock appreciation right. Upon our adoption of SFAS 123(R), we began recognizing compensation expense based upon the estimated grant date fair value of the Class B partnership equity awards.

The fair value of the Class B partnership equity awards was estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards of five years; (ii) a risk-free interest rate of 4.1%; (iii) an expected dividend yield on units of Enterprise GP Holdings of 3%; and (iv) an expected Enterprise GP Holdings unit price volatility of 30%. In general, the methodology we followed to estimate the fair value of the Class B partnership equity awards is similar to that used to estimate the fair value of Enterprise Products Partners unit options.

During the three and six months ended June 30, 2006, we recognized $0.6 million and $1.1 million of compensation expense, respectively, associated with such profits interests. As of June 30, 2006, there was $10.5 million of total unrecognized compensation cost related to the profits interests, of which we estimate our allocable share to be $9.7 million. That cost is expected to be recognized on a straight-line basis through the third quarter of 2010.

4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in certain interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair value hedges Interest rate swaps. As summarized in the following table, we had eleven interest rate swap agreements outstanding at June 30, 2006 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.15%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 6.69%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 6.14%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.73%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The total fair value of these eleven interest rate swaps at June 30, 2006 and December 31, 2005, was a liability of $64.9 million and $19.2 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2006 and 2005 reflects a $1.1 million expense and a $2.9 million benefit from these swap agreements, respectively. For the six months ended June 30, 2006 and 2005, interest expense reflects a $0.9 million expense and a $7.5 million benefit, respectively, from these swap agreements.

Cash flow hedges Treasury Locks. During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership s purpose of entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt. In July 2006, the Operating Partnership issued $300 million in principal amount of its Junior Notes A (see Note 19). Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with such products, we may enter into commodity financial instruments. The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products.

The fair value of our commodity financial instrument portfolio at June 30, 2006 and December 31, 2005 was a liability of $7.8 million and $0.1 million, respectively. During the three and six months ended June 30, 2006, we recorded $5.7 million and $5.3 million of expense related to our commodity financial instruments, respectively, which is included in operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income. We recorded nominal amounts of earnings from our commodity financial instruments during the three and six months ended June 30, 2005.

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5. Inventories

The following table shows our inventory amounts at the dates indicated:

	June 30, 2006	December 31, 2005
Working inventory	$406,169	$279,237
Forward-sales inventory	45,068	60,369
Inventory	$451,237	$339,606

Our regular trade (or working) inventory is comprised of inventories of natural gas, NGLs, and petrochemical products that are available for sale or used by us in the provision of services. Our forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts. Both inventories are valued at the lower of average cost or market.

Costs and expenses, as shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income, include cost of sales related to the sale of inventories. For the three months ended June 30, 2006 and 2005, such consolidated cost of sales amounts were $3 billion and $2.2 billion, respectively. We recorded $5.7 billion and $4.3 billion of such consolidated cost of sales amounts for the six months ended June 30, 2006 and 2005, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market adjustments when the carrying values of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. For the three months ended June 30, 2006 and 2005, we recognized $0.3 million and $7.4 million, respectively, of lower of cost or market adjustments. We recorded $12 million and $17 million of such adjustments for the six months ended June 30, 2006 and 2005, respectively.

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6. Property, Plant and Equipment

The following table shows our property, plant and equipment and accumulated depreciation at the dates indicated:

	Estimated Useful Life in Years	June 30, 2006	December 31, 2005
Plants and pipelines [1]	5 35 [5]	$ 8,489,508	$ 8,209,580
Underground and other storage facilities [2]	5 35 [5]	552,458	549,923
Platforms and facilities [3]	23 31	161,880	161,807
Transportation equipment [4]	3 10	22,245	24,939
Land		38,589	38,757
Construction in progress		1,074,165	854,595
Total		10,338,845	9,839,601
Less accumulated depreciation		1,320,570	1,150,577
Property, plant and equipment, net		$ 9,018,275	$ 8,689,024

(1) Plants and pipelines includes processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water

wells; and related assets.

(3) Platforms and facilities includes offshore platforms and related facilities and other associated assets.

(4) Transportation equipment includes vehicles and similar assets used in our operations.

(5) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category

are:
underground
storage
facilities,
20-35 years
(with some
components at
5 years); storage
tanks,
10-35 years; and
water wells,
25-35 years
(with some
components at
5 years).

Depreciation expense for the three months ended June 30, 2006 and 2005 was $86.9 million and $79.2 million, respectively. We recorded $170.4 million and $158.1 million of depreciation expense for the six months ended June 30, 2006 and 2005, respectively. Capitalized interest on our construction projects for the three months ended June 30, 2006 and 2005 was $12.4 million and $3.2 million, respectively. We recorded $21.6 million and $7.6 million of capitalized interest on our construction projects for the six months ended June 30, 2006 and 2005, respectively.

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7. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 12. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at June 30, 2006	Investments in and advances to Unconsolidated Affiliates at June 30, 2006	Investments in and advances to Unconsolidated Affiliates at December 31, 2005
NGL Pipelines & Services:			
Venice Energy Services Company, LLC (VESCO)	13.1%	$ 38,609	$ 39,689
K/D/S Promix LLC (Promix)	50%	55,330	65,103
Baton Rouge Fractionators LLC (BRF)	32.3%	26,096	25,584
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	4,547	3,151
Coyote Gas Treating, LLC (Coyote)	50%	1,510	1,493
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (Poseidon)	36%	62,296	62,918
Cameron Highway Oil Pipeline Company (Cameron Highway)	50%	62,789	58,207
Deepwater Gateway, L.L.C. (Deepwater Gateway)	50%	115,628	115,477
Neptune Pipeline Company, L.L.C. (Neptune)	25.67%	67,405	68,085
Nemo Gathering Company, LLC (Nemo)	33.92%	10,527	12,157
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	14,870	15,212
La Porte (2)	50%	4,998	4,845
Total		$ 464,605	$ 471,921

(1) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(2) Refers to our ownership interests in La Porte Pipeline Company, L.P.

and La Porte GP, LLC, collectively.

On occasion, the price we pay to purchase an equity interest in a company exceeds the underlying book capital account we acquire. Such excess cost amounts are included within our investments in and advances to unconsolidated affiliates. At June 30, 2006, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts totaling $47 million, all of which was attributed to values in excess of the underlying tangible asset values. Amortization of such excess cost amounts was $0.6 million and $0.5 million during the three months ended June 30, 2006 and 2005, respectively. For the six months ended June 30, 2006 and 2005, amortization of such amounts was $1.1 million and $1.2 million, respectively.

The following table shows our equity in income of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
NGL Pipelines & Services	$ 1,924	$ 2,837	$ 3,442	$ 7,285
Onshore Natural Gas Pipelines & Services	904	682	1,506	1,262
Offshore Pipelines & Services (1)	4,769	(1,075)	6,703	1,900
Petrochemical Services	415	137	390	413
Total	$ 8,012	$ 2,581	$ 12,041	$ 10,860

(1) Equity earnings from Cameron Highway for the three and six months ended June 30, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway s project debt in June 2005. The reduction in equity earnings from Cameron Highway for the three and six months ended June 30, 2005, is offset by increases in

equity earnings from investments we acquired in connection with the GulfTerra Merger.

Summarized financial information of unconsolidated affiliates

The following table presents unaudited income statement data for our current unconsolidated affiliates, aggregated by business segment, for the periods indicated (on a 100% basis).

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2006			June 30, 2005		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services [1]	$60,220	$ (2,238)	$ (1,785)	$69,382	$14,060	$ 14,392
Onshore Natural Gas Pipelines & Services	77,381	2,363	1,722	82,054	4,055	1,251
Offshore Pipelines & Services [2]	39,554	20,166	12,804	37,289	18,886	(10,468)
Petrochemical Services	5,557	1,645	1,665	3,952	720	730

(1) The decrease in earnings generated by the unconsolidated affiliates within our NGL Pipelines & Services segment is primarily attributable to losses incurred by VESCO due to the effects of Hurricane Katrina.

(2) Earnings for Cameron Highway for the three months ended June 30, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway s

project debt in June 2005.

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2006			June 30, 2005		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services [1]	$ 80,506	$ (24,363)	$ (23,463)	$ 139,346	$ 27,833	$ 28,431
Onshore Natural Gas Pipelines & Services	159,723	4,705	2,914	135,048	6,202	2,323
Offshore Pipelines & Services [2]	71,250	31,096	16,484	67,652	33,796	(1,565)
Petrochemical Services	9,425	1,831	1,875	8,047	1,849	1,871

(1) The decrease in earnings generated by the unconsolidated affiliates within our NGL Pipelines & Services segment is primarily attributable to losses incurred by VESCO due to the effects of Hurricane Katrina.

(2) Earnings for Cameron Highway for the six months ended June 30, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway s project debt in June 2005.

8. Business Acquisitions

In March 2006, we paid $38.1 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. This acquisition was accounted for under the purchase method of accounting and, accordingly, the cost has been allocated based on estimated preliminary fair values as follows:

Property, plant and equipment, net	$ 469
Intangible assets	37,631
Total assets acquired	$ 38,100
Total consideration given	$ 38,100

Management developed the fair value estimates underlying this preliminary purchase price allocation using recognized business valuation techniques.

After completing this acquisition, we commenced construction to increase the capacity of the Pioneer natural gas processing plant, and started work on a related cryogenic natural gas processing facility. Upon completion of the cryogenic natural gas processing facility, we will have the required capacity to process natural gas production from the Jonah and Pinedale fields that is expected to be transported to our Wyoming facilities as a result of the contract rights we acquired from TEPPCO. See Note 9 for information regarding the intangible assets recorded in connection with this acquisition.

See Note 19 for subsequent events involving (i) our acquisition of natural gas pipeline assets located in South Texas in July 2006 and (ii) our acquisition of an NGL pipeline from ExxonMobil in August 2006.

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9. Intangible Assets and Goodwill

Identifiable Intangible assets

The following table summarizes our intangible assets by segment. Our intangible assets primarily consist of contracts and customer relationships.

	At June 30, 2006			At December 31, 2005	
Business Segment	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services [1]	$ 392,894	$ (92,150)	$300,744	$ (79,485)	$275,778
Onshore Natural Gas Pipelines & Services	457,798	(60,761)	397,037	(43,955)	413,843
Offshore Pipelines & Services	207,012	(43,947)	163,065	(32,480)	174,532
Petrochemical Services	56,674	(8,197)	48,477	(7,201)	49,473
Total	$1,114,378	$(205,055)	$909,323	$(163,121)	$913,626

(1) During the first six months of 2006, we recorded an additional $37.6 million of intangible assets in connection with our acquisition of the Pioneer natural gas processing plant and associated natural gas processing rights. The value we assigned to these processing rights will be amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other industry factors.

The following table shows amortization expense by segment associated with our intangible assets for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
NGL Pipelines & Services	$ 6,304	$ 7,045	$ 12,665	$ 13,472
Onshore Natural Gas Pipelines & Services	8,348	8,847	16,806	17,820
Offshore Pipelines & Services	5,633	6,488	11,467	13,210
Petrochemical Services	497	508	996	997
Total	$ 20,782	$ 22,888	$ 41,934	$ 45,499

For the remainder of 2006, amortization expense associated with our intangible assets is currently estimated at $40.6 million.

Goodwill

The following table summarizes our goodwill amounts by segment at the dates indicated. Of the $494 million of goodwill at June 30, 2006, $387.1 million was recorded in connection with the merger of GulfTerra Energy Partners, L.P. (GulfTerra) with a wholly owned subsidiary of Enterprise Products Partners in September 2004.

	June 30, 2006	December 31, 2005

NGL Pipelines & Services	$ 54,942	$ 54,960
Onshore Natural Gas Pipelines & Services	282,977	282,997
Offshore Pipelines & Services	82,386	82,386
Petrochemical Services	73,690	73,690
Totals	$493,995	$494,033

10. Debt Obligations

Our consolidated debt consisted of the following at the dates indicated:

	June 30, 2006	December 31, 2005
Operating Partnership debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011 (1)	$ 530,000	$ 490,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Dixie Revolving Credit Facility, variable rate, due June 2007	10,000	17,000
Debt obligations assumed from GulfTerra	5,068	5,068
Total principal amount	4,899,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value (2)	(77,667)	(32,287)
Long-term debt	$4,821,401	$4,833,781
Standby letters of credit outstanding	$ 46,558	$ 33,129

(1) In June 2006, the Operating Partnership executed a second amendment (the Second Amendment) to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to the remaining $48 million in commitments mature in October 2010.

(2) The June 30, 2006 amount includes $64 million related to fair value hedges and $13.7 million in net unamortized discounts. The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts.

Parent-Subsidiary guarantor relationships

We guarantee the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes assumed from GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation.

Operating Partnership debt obligations

Apart from that discussed below, there have been no significant changes in the terms of our Operating Partnership s debt obligations since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

In March 2006, we generated net proceeds of $430 million in connection with the sale of 18,400,000 of our common units in an underwritten equity offering. Subsequently, this amount was contributed to the Operating Partnership, which, in turn, used this amount to temporarily reduce debt outstanding under its Multi-Year Revolving Credit Facility.

In June 2006, the Operating Partnership executed a second amendment (the Second Amendment) to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to $48 million in commitments mature in October 2010. The Second Amendment also modifies the Operating Partnership s financial covenants to, among other things, allow the Operating Partnership to

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include in the calculation of its Consolidated EBITDA (as defined in the credit agreement) pro forma adjustments for material capital projects. In addition, the Second Amendment allows for the issuance of hybrid debt, such as the $300 million in principal amount of fixed/floating unsecured junior subordinated notes issued by the Operating Partnership in July 2006 (see Note 19).

Covenants

We were in compliance with the covenants of our consolidated debt agreements at June 30, 2006 and December 31, 2005.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the six months ended June 30, 2006.

	Range of interest rates paid	**Weighted-average interest rate paid**
Operating Partnership s Multi-Year Revolving Credit Facility	4.87% to 8.00%	5.35%
Dixie Revolving Credit Facility	4.67% to 5.55%	5.00%

Consolidated debt maturity table

Our scheduled maturities of debt principal amounts over the next five years and in total thereafter are presented in the following table. No amounts are currently due in 2006 or 2008.

2007	$ 510,000
2009	500,000
2010	607,068
Thereafter	3,282,000
Total scheduled principal payments	$ 4,899,068

Joint venture debt obligations

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at June 30, 2006, (ii) total debt of each unconsolidated affiliate at June 30, 2006 (on a 100% basis to the joint venture) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest		**Scheduled Maturities of Debt**					
		Total	**2006**	**2007**	**2008**	**2009**	**2010**	**After 2010**
Cameron Highway	50.0%	$ 415,000			$ 25,000	$ 25,000	$ 50,000	$ 315,000
Poseidon	36.0%	92,000						92,000
Evangeline	49.5%	30,650	$ 5,000	$ 5,000	5,000	5,000	10,650	
Total		$ 537,650	$ 5,000	$ 5,000	$ 30,000	$ 30,000	$ 60,650	$ 407,000

The credit agreements of our joint ventures contain various affirmative and negative covenants, including financial covenants. Our joint ventures were in compliance with all such covenants at June 30, 2006.

Amendment of Cameron Highway debt. In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays. In general, this amendment modified certain financial covenants in light of production forecasts made by management. In addition, the amendment increased the face amount of the letters of credit required to be issued by the Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

Also, the amendment specifies that Cameron Highway cannot make distributions to its partners during the period beginning March 30, 2006 and ending on the earlier of (i) December 31, 2007 or (ii) the date on which Cameron Highway s debt service coverage ratios are not less than 1.5 to 1 for three consecutive fiscal quarters. In order for Cameron Highway to resume paying distributions to its partners, no default or event of default can be present or continuing at the date Cameron Highway desires to start paying such distributions.

Amendment of Poseidon debt. In May 2006, Poseidon amended its revolving credit facility to, among other things, reduce commitments from $170 million to $150 million, extend the maturity date from January 2008 to May 2011 and lower the borrowing rate.

11. Partners Equity

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights and privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the Partnership Agreement). We are managed by our general partner, Enterprise Products GP.

Capital accounts

In accordance with our Partnership Agreement, capital accounts 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 GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to our general partner.

Equity offerings and registration statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by Enterprise Products GP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders). The following table reflects the number of common units issued and the net proceeds received from each public offering during the six months ended June 30, 2006:

		Net Proceeds from Sale of Common Units		
Month of Offering	**Number of common units issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total**
February 2006	418,190	$ 9,972	$ 203	$ 10,175
March 2006	18,400,000	421,419	8,601	430,020
May 2006	477,646	11,441	234	11,675
	19,295,836	$442,832	$ 9,038	$451,870

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We have a universal shelf registration statement on file with the SEC registering the issuance of up to $4 billion of equity and debt securities. After taking into account the past issuance of securities under this universal registration statement, we can issue approximately $3 billion of additional securities under this registration statement as of June 30, 2006.

In July 2006, we issued approximately 7.1 million of our common units as partial consideration for our acquisition of natural gas pipeline assets located in South Texas. We are obligated to file a registration statement with the SEC for the resale of these common units. See Note 19 for additional information regarding this subsequent event.

Summary of limited partner transactions

The following table details the changes in limited partners equity since December 31, 2005:

	Limited Partners		
	Common units	Restricted Common units	Total
Balance, December 31, 2005	$5,542,700	$ 18,638	$5,561,338
Net income	215,103	458	215,561
Operating leases paid by EPCO	1,033	2	1,035
Cash distributions to partners	(351,787)	(658)	(352,445)
Unit option reimbursements to EPCO	(710)		(710)
Net proceeds from sales of common units	442,832		442,832
Proceeds from exercise of unit options	1,573		1,573
Change in accounting method for equity awards (see Note 3)	(896)	(14,918)	(15,814)
Amortization of equity awards	1,184	3,058	4,242
Balance, June 30, 2006	$5,851,032	$ 6,580	$5,857,612

Unit history

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Limited Partners	
	Common units	Restricted Common units
Balance, December 31, 2005	389,109,564	751,604
Common units issued in February 2006	418,190	
Common units issued in February 2006 in connection with exercises of unit options	29,000	
Restricted common units issued in February 2006		17,500
Vesting of restricted units in February 2006	2,434	(2,434)
Common units issued in connection with March 2006 public offering	18,400,000	
Forfeiture of restricted units in March 2006		(26,021)
Vesting of restricted units in April 2006	37,277	(37,277)
Forfeiture of restricted units in April 2006		(1,000)
Common units issued in May 2006	477,646	
	34,000	

Common units issued in May 2006 in connection with exercises of unit options		
Restricted common units issued in May 2006		382,900
Forfeiture of restricted units in May 2006		(1,000)
Forfeiture of restricted units in June 2006		(9,255)
Balance, June 30, 2006	408,508,111	1,075,017

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Distributions

As an incentive, Enterprise Products GP s percentage interest in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. Enterprise Products GP s quarterly incentive distribution thresholds are as follows:

2% of quarterly cash distributions up to $0.253 per unit;

15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and

25% of quarterly cash distributions that exceed $0.3085 per unit.

Our quarterly cash distributions for 2006 are presented in the following table:

	Cash Distribution History		
	Distribution per Unit	Record Date	Payment Date
1st Quarter 2006	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter 2006	$0.4525	Jul. 31, 2006	Aug. 10, 2006

Accumulated other comprehensive income

The following table summarizes transactions affecting our accumulated other comprehensive income since December 31, 2005.

	Commodity Financial Instruments	Interest Rate Financial Instruments	Accumulated Other Comprehensive Income Balance
Balance, December 31, 2005		$19,072	$ 19,072
Change in fair value of commodity financial instruments	$(7,700)		(7,700)
Reclassification of gain on settlement of interest rate financial instruments		(2,093)	(2,093)
Reclassification of change in fair value of interest rate financial instruments		1,638	1,638
Balance, June 30, 2006	$(7,700)	$18,617	$ 10,917

During the remainder of 2006, we will reclassify $2.1 million from accumulated other comprehensive income to earnings as a reduction in consolidated interest expense.

12. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues and operating costs and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system through a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we typically earn revenues based on volume or receive an ownership of products such as NGLs.

Many of our equity investees are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe the treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

Our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi and New Mexico. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset s or investment s principal operations. The principal reconciling item between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of a particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to each segment based on the classification of the assets to which they relate.

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The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues (1)	$ 3,517,853	$ 2,671,768	$ 6,767,927	$ 5,227,290
Less: Operating costs and expenses (1)	(3,323,585)	(2,530,133)	(6,370,448)	(4,913,777)
Add: Equity in income of unconsolidated affiliates (1)	8,012	2,581	12,041	10,860
Depreciation, amortization and accretion in operating costs and expenses (2)	107,952	101,048	212,768	201,013
Operating lease expense paid by EPCO (2)	528	528	1,056	1,056
Loss (gain) on sale of assets in operating costs and expenses (2)	(136)	83	(197)	(5,353)
Total segment gross operating margin	$ 310,624	$ 245,875	$ 623,147	$ 521,089

(1) These amounts are taken from our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income.

(2) These non-cash expenses are taken from the operating activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

A reconciliation total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005

Total segment gross operating margin	$ 310,624	$ 245,875	$ 623,147	$ 521,089
Adjustments to reconcile total gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(107,952)	(101,048)	(212,768)	(201,013)
Operating lease expense paid by EPCO	(528)	(528)	(1,056)	(1,056)
Gain (loss) on sale of assets in operating costs and expenses	136	(83)	197	5,353
General and administrative costs	(16,235)	(18,710)	(29,975)	(33,403)
Consolidated operating income	186,045	125,506	379,545	290,970
Other expense	(52,940)	(55,501)	(109,048)	(107,995)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 133,105	$ 70,005	$ 270,497	$ 182,975

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	**Onshore Pipelines & Services**	**Offshore Pipelines & Services**	**Petrochemical Services**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:						
Three months ended June 30, 2006	$2,553,212	$ 308,410	$ 29,506	$ 513,291		$3,404,419
Three months ended June 30, 2005	1,945,196	259,213	31,984	354,427		2,590,820
Six months ended June 30, 2006	4,891,908	721,411	51,858	899,241		6,564,418
Six months ended June 30, 2005	3,802,650	506,147	61,532	717,820		5,088,149
Revenues from related parties:						
Three months ended June 30, 2006	37,101	75,914	419			113,434
Three months ended June 30, 2005	1,858	78,816	253	21		80,948
Six months ended June 30, 2006	44,049	158,869	591			203,509
Six months ended June 30, 2005	3,620	135,031	439	51		139,141
Intersegment and intrasegment revenues:						
Three months ended June 30, 2006	1,077,547	31,588	390	103,449	$(1,212,974)	
Three months ended June 30, 2005	767,030	8,400	432	87,137	(862,999)	
Six months ended June 30, 2006	1,973,792	59,729	703	186,266	(2,220,490)	
Six months ended June 30, 2005	1,496,707	18,417	628	141,887	(1,657,639)	
Total revenues:						
Three months ended June 30, 2006	3,667,860	415,912	30,315	616,740	(1,212,974)	3,517,853
Three months ended June 30, 2005	2,714,084	346,429	32,669	441,585	(862,999)	2,671,768
Six months ended June 30, 2006	6,909,749	940,009	53,152	1,085,507	(2,220,490)	6,767,927
	5,302,977	659,595	62,599	859,758	(1,657,639)	5,227,290

Six months ended June 30, 2005						
Equity in income in unconsolidated affiliates:						
Three months ended June 30, 2006	1,924	904	4,769	415		8,012
Three months ended June 30, 2005	2,837	682	(1,075)	137		2,581
Six months ended June 30, 2006	3,442	1,506	6,703	390		12,041
Six months ended June 30, 2005	7,285	1,262	1,900	413		10,860
Gross operating margin by individual business segment and in total:						
Three months ended June 30, 2006	146,414	86,651	20,515	57,044		310,624
Three months ended June 30, 2005	120,328	84,903	22,034	18,610		245,875
Six months ended June 30, 2006	317,364	183,454	37,767	84,562		623,147
Six months ended June 30, 2005	273,632	164,261	45,258	37,938		521,089
Segment assets:						
At June 30, 2006	3,143,499	3,557,642	733,047	509,922	1,074,165	9,018,275
At December 31, 2005	3,075,048	3,622,318	632,222	504,841	854,595	8,689,024
Investments in and advances to unconsolidated affiliates (see Note 7):						
At June 30, 2006	120,035	6,057	318,645	19,868		464,605
At December 31, 2005	130,376	4,644	316,844	20,057		471,921
Intangible Assets (see Note 9):						
At June 30, 2006	300,744	397,037	163,065	48,477		909,323
At December 31, 2005	275,778	413,843	174,532	49,473		913,626
Goodwill (see Note 9):						
At June 30, 2006	54,942	282,977	82,386	73,690		493,995
At December 31, 2005	54,960	282,997	82,386	73,690		494,033

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Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 69% and 66% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 68% and 66% for the six months ended June 30, 2006 and 2005, respectively. Revenues from the sale and marketing of petrochemical products within the Petrochemical Services segment accounted for 11% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 11% and 12% for the six months ended June 30, 2006 and 2005, respectively. Revenues from the sale and marketing of natural gas using onshore assets accounted for 8% and 9% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 9% and 8% for the six months ended June 30, 2006 and 2005, respectively.

13. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Revenues from consolidated operations				
EPCO and affiliates	$ 33,448	$ 2	$ 39,080	$ 286
Unconsolidated affiliates	79,986	80,946	164,429	138,855
Total	$113,434	$80,948	$203,509	$139,141
Operating costs and expenses				
EPCO and affiliates	$ 71,105	$64,991	$166,062	$123,994
Unconsolidated affiliates	7,904	3,898	14,590	10,466
Total	$ 79,009	$68,889	$180,652	$134,460
General and administrative expenses				
EPCO and affiliates	$ 10,830	$11,119	$ 21,838	$ 20,794

Relationship with EPCO and affiliates

General. We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

§ EPCO and its private company subsidiaries;

§ Enterprise Products GP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ the Employee Partnership; and

§ TEPPCO and its general partner (TEPPCO GP), which are controlled by affiliates of EPCO.

Unless noted otherwise, our agreements with EPCO are not the result of arm s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP, our general partner. At June 30, 2006, EPCO and its affiliates beneficially owned 144,384,693 (or 34.5%) of our outstanding common units. In addition, at June 30, 2006, EPCO and its affiliates owned 86.7% of Enterprise GP Holdings, including 100% of EPE Holdings.

The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and EPE Holdings are employees of EPCO.

In connection with its general partner interest in us, Enterprise Products GP received cash distributions of $47.3 million and $35.3 million from us during the six months ended June 30, 2006 and 2005, respectively. These amounts include $40.1 million and $29.1 million of incentive distributions for the six months ended June 30, 2006 and 2005, respectively. Enterprise GP Holdings owns all of the membership interests of Enterprise Products GP.

We and Enterprise Products GP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise GP Holdings and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received $148.3 million and $117.8 million in cash distributions from us during the six months ended June 30, 2006 and 2005, respectively, in connection with its limited and general partner interests in us.

The ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. In addition, we buy and sell NGL products to and from a foreign affiliate of EPCO at market-related prices in the normal course of business.

Relationship with TEPPCO. We received $11.5 million and $17 million from TEPPCO during the three and six months ended June 30, 2006, respectively, from the sale of hydrocarbon products. During the three months ended June 30, 2006 and 2005, we paid TEPPCO $6.2 million and $7.1 million, respectively, for NGL pipeline transportation and storage services. We paid TEPPCO $10.6 million and $8.6 million for NGL pipeline transportation and storage services during the six months ended June 30, 2006 and 2005, respectively.

In March 2006, we paid $38.1 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our general partner and the general partner of TEPPCO, and a fairness opinion was rendered by an independent third-party. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility. In addition, the unaudited pro forma financial impact of this transaction is not significant.

In August 2006, we announced a joint venture in which we and TEPPCO will be partners in TEPPCO s Jonah Gas Gathering Company. The Jonah Gas Gathering Company owns the Jonah Gas Gathering System (the Jonah system), located in the Greater Green River Basin of southwestern Wyoming, which gathers and transports natural gas produced from the Jonah and Pinedale fields to natural gas processing plants and major interstate pipelines that deliver natural gas to end-use markets.

A letter of intent executed by us and TEPPCO in February 2006 provided that we would manage the construction and fund the initial capital cost of the Phase V expansion of the Jonah system. In connection with the joint venture arrangement, we and TEPPCO intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to 2.4 Bcf/d 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 believed to increase the system gathering capacity to 2 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $275 million. The second portion of the expansion is expected to cost approximately $140 million and be completed by the end of 2007.

We will manage the Phase V construction project, and in the third quarter of 2006, TEPPCO will reimburse us for 50% of the Phase V capital cost incurred through August 1, 2006. After August 1, 2006, we and TEPPCO will equally share the capital costs of the Phase V expansion. Our ultimate ownership interest in Jonah Gas Gathering Company will be based on our share of the total cost of the Phase V expansion. Upon completion of the expansion project, we and TEPPCO are expected to own an approximate 20% and 80% interest, respectively, in Jonah Gas Gathering Company, with us serving as operator. Our expenditures associated with this project were $106.9 million during the six months ended June 30, 2006, of which $97.8 million has been paid to vendors. Other assets on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2006 include the $106.9 million of expenditures related to this project.

Administrative Services Agreement. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (ASA). We and our general partner, Enterprise GP Holdings and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees.

Relationships with unconsolidated affiliates

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline and the purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix and process natural gas at VESCO.

14. Earnings per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units (excluding restricted units) outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of time-vested and performance-based restricted common units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the incremental option units).

In a period of net operating losses, the restricted units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner s share of such earnings. The following table shows the allocation of net income to our general partner for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$126,295	$ 70,659	$260,072	$179,915
Less incentive earnings allocations to Enterprise Products GP	(20,997)	(15,516)	(40,112)	(29,136)
Net income available after incentive earnings allocation	105,298	55,143	219,960	150,779
Multiplied by Enterprise Products GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise Products GP	$ 2,106	$ 1,103	$ 4,399	$ 3,016

Incentive earnings allocation to Enterprise Products GP	$ 20,997	$ 15,516	$ 40,112	$ 29,136
Standard earnings allocation to Enterprise Products GP	2,106	1,103	4,399	3,016
Enterprise Products GP interest in net income	$ 23,103	$ 16,619	$ 44,511	$ 32,152

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The following table shows the calculation of our limited partners interest in net income and basic and diluted earnings per unit.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Income before change in accounting principle and Enterprise Products GP interest	$126,295	$ 70,659	$258,597	$179,915
Cumulative effect of change in accounting principle			1,475	
Net income	126,295	70,659	260,072	179,915
Enterprise Products GP interest in net income	(23,103)	(16,619)	(44,511)	(32,152)
Net income available to limited partners	$103,192	$ 54,040	$215,561	$147,763
BASIC EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$126,295	$ 70,659	$258,597	$179,915
Cumulative effect of change in accounting principle			1,475	
Enterprise Products GP interest in net income	(23,103)	(16,619)	(44,511)	(32,152)
Limited partners interest in net income	$103,192	$ 54,040	$215,561	$147,763
Denominator				
Common units	408,275	383,734	401,820	378,376
Basic earnings per unit				
Income per unit before change in accounting principle and Enterprise Products GP interest	$ 0.31	$ 0.18	$ 0.64	$ 0.47
Cumulative effect of change in accounting principle			0.01	
Enterprise Products GP interest in net income	(0.06)	(0.04)	(0.11)	(0.08)
Limited partners interest in net income	$ 0.25	$ 0.14	$ 0.54	$ 0.39
DILUTED EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$126,295	$ 70,659	$258,597	$179,915
Cumulative effect of change in accounting principle			1,475	
Enterprise Products GP interest in net income	(23,103)	(16,619)	(44,511)	(32,152)

Limited partners interest in net income	$103,192	$ 54,040	$215,561	$147,763
Denominator				
Common units	408,275	383,734	401,820	378,376
Time-vested restricted units	968	495	862	495
Performance-based restricted units	27	54	27	54
Incremental option units	234	526	241	612
Total	409,504	384,809	402,950	379,537
Diluted earnings per unit				
Income per unit before change in accounting principle and Enterprise Products GP interest	$ 0.31	$ 0.18	$ 0.64	$ 0.47
Cumulative effect of change in accounting principle			0.01	
Enterprise Products GP interest in net income	(0.06)	(0.04)	(0.11)	(0.08)
Limited partners interest in net income	$ 0.25	$ 0.14	$ 0.54	$ 0.39

15. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we insure against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position, cash flows or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against various manufacturers of reformulated gasoline containing methyl tertiary butyl ether (MTBE). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

We acquired additional ownership interests in our octane-additive production facility from affiliates of Devon Energy Corporation (Devon), which sold us its 33.3% interest in 2003, and Sunoco, Inc. (Sun), which sold us its 33.3% interest in 2004. As a result of these acquisitions, we own 100% of our Mont Belvieu, Texas octane-additive production facility. Devon and Sun have indemnified us for any liabilities (including potential liabilities as described in the preceding paragraph) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in our octane-additive production facility.

Operating leases

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 14 to 20 years and include renewal options that could extend the agreements for up to an additional 20 years. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Lease and rental expense included in operating income was $10 million and $8.9 million for the three months ended June 30, 2006 and 2005, respectively. For the six months ended June 30, 2006 and 2005, lease and rental expense included in operating income was $19.7 million and $18.2 million, respectively.

There have been no material changes in our operating lease commitments since December 31, 2005, except for the renewal of our Wilson natural gas storage facility lease. During the first quarter of 2006, we exercised our right to renew the Wilson lease for an additional 20-year period. Our rental payments under the renewal agreement are at a fixed rate. Under the renewal agreement, we have the option to purchase the Wilson natural gas storage facility at either December 31, 2024 for $61 million or January 25, 2028 for $55 million. In addition, the lessor, at its election, may cause us to purchase the facility for $65 million at the end of any calendar quarter beginning on March 31, 2008 and extending through December 31, 2023. After adjusting for the renewal, the incremental future minimum lease payments associated with our lease of the Wilson natural gas storage facility are as follows: $4.1 million, 2008; $5.5 million, 2009; $5.5 million, 2010; and $94.9 million thereafter.

Performance guaranty

In December 2004, a subsidiary of the Operating Partnership entered into the Independence Hub Agreement (the Hub Agreement) with six oil and natural gas producers. The Hub Agreement, as amended, obligates the subsidiary (i) to construct an offshore platform production facility to process 1

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Bcf/d of natural gas and condensate and (ii) to process certain natural gas and condensate production of the six producers following construction of the platform facility.

In conjunction with the Hub Agreement, our Operating Partnership guaranteed the performance of its subsidiary under the Hub Agreement up to $426 million. In December 2004, 20% of this guaranteed amount was assumed by Helix Energy Solutions Group, Inc. (formerly known as Cal Dive International, Inc.), our joint venture partner in the Independence Hub project. The remaining $341 million represents our share of the anticipated construction cost of the platform facility. This amount represents the cap on our Operating Partnership s potential obligation to the six producers for the cost of constructing the platform under the remote scenario where the six producers finish construction of the platform facility. This performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of the subsidiary shall have been terminated, paid or otherwise discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We currently expect that mechanical completion of the platform will occur in January 2007; therefore, we anticipate that the performance guaranty will exist until at least this future period.

In accordance with FIN 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, we recorded the fair value of the performance guaranty using an expected present value approach. Given the remote probability that our Operating Partnership would be required to perform under this guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of other current liabilities on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2006.

16. Significant Risks and Uncertainties Weather-Related Risks

EPCO renewed its property and casualty insurance programs during the second quarter of 2006. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage were difficult. Under our renewed insurance programs, coverage is more restrictive including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will also be applied in the event of damage from named windstorms.

In addition to changes in coverages, the cost of property damage insurance increased substantially from prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $49.2 million, which represents a $28.1 million (or 133%) increase from our 2005 annualized insurance cost.

The following is a discussion of the general status of insurance claims related to significant storm events that affected our assets in 2004 and 2005. To the extent we include estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the GulfTerra Merger) included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During the first quarter of 2006, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million in late 2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the first quarter of 2006, we received claim proceeds of $10.2 million, and in April 2006 we received an additional $2 million. To the extent we receive cash proceeds from business interruption insurance claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection, evaluation and repair of property damage to our facilities is continuing. To the extent that insurance proceeds from property damage claims do not cover our estimated recoveries (in excess of the $5 million of insurance deductibles we expensed during the third quarter of 2005), such shortfall will be charged to earnings when realized. We recorded $63.5 million of estimated recoveries from property damage claims arising from Hurricanes Katrina and Rita, based on amounts expended through June 30, 2006. To the extent we receive cash proceeds from business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

17. Supplemental Cash Flow Information

We prepare our Unaudited Condensed Statements of Consolidated Cash Flows using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and the like, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of assets or gains or losses from the extinguishment of debt and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of instruments.

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	For the Six Months Ended June 30,	
	2006	**2005**
Decrease (increase) in:		
Accounts and notes receivable	$ 117,826	$ 65,688
Inventories	(111,631)	(178,770)
Prepaid and other current assets	(48,347)	(19,510)
Other assets	7,601	31,107
Increase (decrease) in:		
Accounts payable	12,898	(114,170)
Accrued gas payable	19,402	(48,553)
Accrued expenses	35,911	(31,062)
Accrued interest	(1,248)	(574)
Other current liabilities	45,843	712
Other long-term liabilities	(3,563)	(1,141)
Net effect of changes in operating accounts	$ 74,692	$ (296,273)

Third parties may be obligated to reimburse us for all or a portion of project expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction projects and production well tie-ins. We received $34.9 million and $27 million as contributions in aid of our construction costs during the six months ended June 30, 2006 and 2005, respectively.

18. Condensed Financial Information of Operating Partnership

The Operating Partnership conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of our Operating Partnership.

We guarantee the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes assumed from GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. For additional information regarding our consolidated debt obligations, see Note 10.

The reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant.

The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	June 30, 2006	December 31, 2005
ASSETS		
Current assets	$ 2,000,077	$ 1,960,015
Property, plant and equipment, net	9,018,275	8,689,024
Investments in and advances to unconsolidated affiliates, net	464,605	471,921
Intangible assets, net	909,323	913,626
Goodwill	493,995	494,033
Deferred tax asset	3,444	3,606
Other assets	147,578	39,014
Total	$13,037,297	$12,571,239
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	$ 1,980,810	$ 1,894,227
Long-term debt	4,821,401	4,833,781
Other long-term liabilities	131,201	84,486
Minority interest	124,497	106,159
Partners equity	5,979,388	5,652,586
Total	$13,037,297	$12,571,239
Total Operating Partnership debt obligations guaranteed by us	$ 4,884,000	$ 4,844,000

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues	$3,517,853	$2,671,768	$6,767,927	$5,227,290
Costs and expenses	3,339,326	2,548,221	6,397,972	4,945,867
	8,012	2,581	12,041	10,860

Equity in income of unconsolidated affiliates				
Operating income	186,539	126,128	381,996	292,283
Other income (expense)	(53,413)	(55,741)	(109,925)	(108,216)
Income before provision for income taxes, minority interest and change in accounting principle	133,126	70,387	272,071	184,067
Provision for income taxes	(6,272)	1,034	(9,164)	(735)
Income before minority interest and change in accounting principle	126,854	71,421	262,907	183,332
Minority interest	(534)	(392)	(2,733)	(2,333)
Income before change in accounting principle	126,320	71,029	260,174	180,999
Cumulative effect of change in accounting principle			1,475	
Net income	$ 126,320	$ 71,029	$ 261,649	$ 180,999

19. Subsequent Events

July 2006 Junior Notes Offering

In July 2006, the Operating Partnership sold $300 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 (Junior Notes A). The Operating Partnership used the proceeds from issuing this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Operating Partnership s payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). Enterprise Products Partners has guaranteed repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows the Operating Partnership to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the Indenture has occurred and is continuing and (iii) Enterprise Products Partners is not in default of its obligations under related guarantee agreements, then the Operating Partnership and Enterprise Products Partners cannot declare or make any distributions with respect to any of their respective equity securities or make any payments on indebtedness or other obligations that rank *pari passu* with or subordinate to Junior Notes A.

The Junior Notes A will bear fixed rate interest of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, commencing in February 2007. Thereafter, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by the Operating Partnership prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, the Operating Partnership entered into a Replacement Capital Covenant in favor of the covered debtholders (as named therein) pursuant to which the Operating Partnership agreed for the benefit of such debtholders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

July 2006 Acquisition of Natural Gas Gathering Assets in South Texas

In July 2006, we acquired certain natural gas gathering systems and related gathering and processing contracts from Cerrito Gathering Company, Ltd. (Cerrito), an affiliate of Lewis Energy Group, L.P. (Lewis). The total consideration paid by us was $325 million, which consisted of approximately $146 million in cash and the issuance of approximately 7.1 million of our common units.

The Cerrito gathering systems are located in South Texas and are connected to over 1,450 wells having an aggregate production volume of over 100 MMcf/d of natural gas sourced from the Olmos and Wilcox Trends in South Texas. The Cerrito gathering systems consist of 484 miles of pipeline, comprised of 312 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Cerrito gathering system is supported by 31,000 horsepower of compression. Volumes currently gathered by the Cerrito systems are delivered into our South Texas gas processing and pipeline transportation system.

These gathering systems will be supported by a long-term dedication by Lewis of its production from the Olmos formation. In addition to the natural gas gathering and processing dedication, the transaction also includes a long-term dedication to transport lean gas gathered and treated at Lewis Big Reef Treating facility. The Big Reef facility will gather and treat sour gas production from the southern portion of the Edwards Trend in South Texas.

August 2006 Purchase of NGL Pipeline

In August 2006, we purchased 226 miles of NGL pipelines extending from Corpus Christi, Texas to Pasadena, Texas from ExxonMobil Pipeline Company. The total purchase price for these assets was $97.9 million in cash. We funded this asset purchase using borrowings under our Multi-Year Revolving Credit Facility. This pipeline will be used to transport mixed NGLs from our South Texas natural gas processing plants to our Mont Belvieu fractionation facilities.

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

For the three and six months ended June 30, 2006 and 2005.

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD. Unless the context requires otherwise, references to we, us, our, or Enterprise Products Partners are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

We are a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our Operating Partnership).

We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol EPE. We, Enterprise Products GP and Enterprise GP Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO, Inc. (EPCO).

This quarterly report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, our general partner, as well as assumptions made by us and information currently available to us. Please read the section titled *Cautionary Statement Regarding Forward-Looking Information* included within this Item 2.

As generally used in the energy industry and in this document, the terms listed below have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
Mdth	= thousand dekatherms
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet
TBtu	= trillion British thermal units

In addition, references to TEPPCO mean TEPPCO Partners, L.P., a publicly traded Delaware limited partnership, which is an affiliate of us. References to TEPPCO GP refer to the general partner of TEPPCO, which is wholly owned by a private company subsidiary of EPCO.

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and notes included under Item 1 of this quarterly report on Form 10-Q and with the information contained within our annual report on Form 10-K for the year ended December 31, 2005 (Commission File No. 1-14323).

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RECENT DEVELOPMENTS

In general, our outlook for 2006 remains the same as that discussed in our annual report on Form 10-K for 2005. The following summarizes our significant developments since December 31, 2005 through the date of this filing.

§ In March 2006, we sold 18,400,000 of our common units in a public offering (including the over-allotment amount of 2,400,000 common units), which generated net proceeds of approximately $430 million.

§ In March 2006, we announced plans to expand our petrochemical assets located in southeast Texas at an expected cost of $205 million. The plans include the construction of a new propylene fractionator at our Mont Belvieu, Texas facility and the expansion of two refinery grade propylene pipelines. These additions are expected to be complete in late 2007.

§ In March 2006, we purchased the Pioneer natural gas processing plant and certain natural gas processing rights from TEPPCO for $38.1 million in cash.

§ In April 2006, we announced plans to expand our Houston Ship Channel NGL import and export facility and related pipeline and other assets to accommodate an expected increase in throughput volumes. This expansion project is expected to cost $40 million and be completed in the second quarter of 2007.

§ In July 2006, the Operating Partnership sold $300 million in principal amount of fixed/floating unsecured junior subordinated notes. For additional information regarding this issuance of debt, please read *Liquidity and Capital Resources* included within this Item 2.

§ In July 2006, we acquired natural gas gathering systems and related gathering and processing contracts from Cerrito Gathering Company, Ltd. (Cerrito), an affiliate of Lewis Energy Group L.P. (Lewis). The total consideration paid by us was $325 million, which consisted of approximately $146 million in cash and the issuance of approximately 7.1 million of our common units.

§ In July 2006, we signed long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint Energy) to provide firm natural gas transportation and storage services to its natural gas utility, primarily in the Houston metropolitan area.

§ In August 2006, we purchased 226 miles of NGL pipelines extending from Corpus Christi, Texas to Pasadena, Texas from ExxonMobil Pipeline Company (ExxonMobil). The total purchase price for these assets was $97.9 million in cash.

For additional information regarding our capital spending and acquisitions, please read *Capital Spending* included within this Item 2.

CAPITAL SPENDING

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We

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forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

Based on information currently available, we estimate our consolidated capital spending during 2006 will approximate $2.1 billion, of which $0.6 billion was spent during the first six months of 2006. Of the remaining $1.5 billion forecast to be spent during the third and fourth quarters of 2006, $1.4 billion is attributable to growth capital projects and acquisitions. The $1.4 billion includes the $325 million of consideration we paid or issued to Lewis in July 2006 to acquire natural gas gathering assets located in South Texas and the $100 million we paid to ExxonMobil in August 2006 to acquire NGL pipelines.

Our forecast of consolidated capital expenditures is based on our strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreement and potential divestitures of assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be the principal factor that determines how much we can spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

The following table summarizes our capital spending by activity for the periods indicated (dollars in thousands):

	For the Six Months Ended June 30,	
	2006	**2005**
Capital spending for business combinations and asset purchases:		
Pioneer natural gas processing plant and associated processing rights purchased from TEPPCO	$ 38,100	
Indirect interests in the Indian Springs natural gas gathering and processing assets		$ 74,854
Additional ownership interests in Dixie Pipeline Company (Dixie)		68,608
Additional ownership interests in Mid-America and Seminole pipeline systems		25,000
Other business combinations		12,617
Total	38,100	181,079
Capital spending for property, plant and equipment:		
Growth capital projects	475,947	371,894
Sustaining capital projects	64,531	36,843
Total	540,478	408,737
Capital spending attributable to unconsolidated affiliates:		
Investments in and advances to unconsolidated affiliates	6,995	81,780
Advances to Jonah affiliate	97,767	
Total capital spending	$683,340	$671,596

Our capital spending for growth capital projects (as presented in the preceding table) are net of amounts we received from third parties as contributions in aid of our construction costs. Such contributions were $34.9 million and $27 million for the six months ended June 30, 2006 and 2005, respectively. On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction projects and production well tie-ins.

At June 30, 2006, we had $200.9 million in outstanding purchase commitments, which primarily relate to growth capital projects in the Rocky Mountains and offshore Gulf of Mexico that are expected to be placed in service in 2006 and 2007.

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Significant Recently Announced Growth Capital Projects

The following summarizes our significant growth capital projects initiated since December 31, 2005 through the date of this filing.

Piceance Basin Gas Processing Project. In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of the EnCana Corporation (EnCana). Under that agreement, we will have the right to process up to 1.3 Bcf/d of EnCana s natural gas production from the Piceance Basin area of western Colorado. To accommodate this production, we have begun construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. In addition, we will construct an approximate 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. The Meeker natural gas processing plant, which will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs, is expected to be placed in service in mid-2007 at a cost of $285 million. We are currently working to secure production dedications from additional producers. In June 2006, EnCana executed an option which requires us to build an expansion of the Meeker facility by mid-2009. Under the terms of the agreement, EnCana has certain guaranteed payment obligations to us.

Wyoming Gas Processing Projects. In January 2006, we announced our intent to purchase from an affiliate of TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights of TEPPCO and its affiliates to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. We completed this acquisition in March 2006 at a cost of $38.1 million and commenced construction to increase the processing capacity of the Pioneer plant from 300 MMcf/d to 600 MMcf/d at an additional cost of $21 million. This expansion was completed in July 2006. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our general partner and the general partner of TEPPCO, and a fairness opinion was rendered by an independent third-party. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility.

In addition, to handle future production growth in the region, we started construction of a new natural gas processing plant in July 2006 having a capacity of 650 MMcf/d adjacent to the Pioneer plant. We expect our new natural gas processing plant to be placed in service by the third quarter of 2007 at an expected cost of $250 million.

Phase V Jonah Expansion. In August 2006, we announced a joint venture in which we and TEPPCO will be partners in TEPPCO s Jonah Gas Gathering Company. The Jonah Gas Gathering Company owns the Jonah Gas Gathering System (the Jonah system), located in the Greater Green River Basin of southwestern Wyoming, which gathers and transports natural gas produced from the Jonah and Pinedale fields to natural gas processing plants and major interstate pipelines that deliver natural gas to end-use markets.

A letter of intent executed by us and TEPPCO in February 2006 provided that we would manage the construction and fund the initial capital cost of the Phase V expansion of the Jonah system. In connection with the joint venture arrangement, we and TEPPCO intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to 2.4 Bcf/d 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 believed to increase the system gathering capacity to 2 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $275 million. The second portion of the expansion is expected to cost approximately $140 million and be completed by the end of 2007.

We will manage the Phase V construction project, and in the third quarter of 2006, TEPPCO will reimburse us for 50% of the Phase V capital cost incurred through August 1, 2006. After August 1, 2006, we and TEPPCO will equally share the capital costs of the Phase V expansion. Our ultimate ownership interest in Jonah Gas Gathering Company will be based on our share of the total cost of the Phase V expansion. Upon completion of the expansion project, we and TEPPCO are expected to own an approximate 20% and 80% interest, respectively, in Jonah Gas Gathering Company, with us serving as operator.

Our expenditures associated with this project were $106.9 million during the six months ended June 30, 2006, of which $97.8 million has been paid to vendors.

Expansion of Mont Belvieu Petrochemical Assets. In March 2006, we announced an expansion of petrochemical assets in Mont Belvieu and southeast Texas. This expansion project includes (i) the construction of a new propylene fractionator at our Mont Belvieu complex, which will increase our propylene/propane fractionation capacity by approximately 15 MBPD and (ii) the expansion of two refinery grade propylene gathering pipelines which will add 50 MBPD of gathering capacity into Mont Belvieu. These projects are expected to be operational by late 2007 and are expected to cost $205 million.

Expansion of Houston Ship Channel Import and Export Facility. In April 2006, we announced an expansion of our NGL import and export terminal located on the Houston Ship Channel. This expansion project will increase offloading capability of our import facility from a maximum peak operating rate of 240 MBPD to 480 MBPD and the maximum loading rate of our export facility from 140 MBPD to 160 MBPD. As part of this expansion project, we will increase the transportation and processing capacities of certain of our assets that serve the terminal in order to accommodate the expected increase in import volumes. This expansion project is expected to cost $40 million and be completed in the second quarter of 2007.

Purchase of Natural Gas Gathering Assets in South Texas. In July 2006, we acquired certain natural gas gathering systems and related gathering and processing contracts from Cerrito, an affiliate of Lewis. Total consideration paid by us was $325 million, comprised of approximately $146 million in cash and the issuance of approximately 7.1 million common units of Enterprise Products Partners.

The Cerrito gathering systems are located in South Texas and are connected to over 1,450 wells having an aggregate production volume of over 100 MMcf/d of natural gas sourced from the Olmos and Wilcox Trends in South Texas. The Cerrito gathering systems consist of 484 miles of pipeline, comprised of 312 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Cerrito gathering system is supported by 31,000 horsepower of compression. Volumes currently gathered by the Cerrito systems are delivered into our South Texas gas processing and pipeline transportation system.

These gathering systems will be supported by a long-term dedication by Lewis of its production from the Olmos formation. In addition to the natural gas gathering and processing dedication, the transaction also includes a long-term dedication to transport lean gas gathered and treated at Lewis Big Reef Treating facility. The Big Reef facility will gather and treat sour gas production from the southern portion of the Edwards Trend in South Texas.

Purchase of NGL Pipeline. In August 2006, we purchased 226 miles of NGL pipelines extending from Corpus Christi, Texas to Pasadena, Texas from ExxonMobil. The total purchase price for these assets was $97.9 million in cash. This pipeline will be used to transport mixed NGLs from our South Texas natural gas processing plants to our Mont Belvieu fractionation facilities.

Mid-America Pipeline System Skellytown to Conway Addition. In June 2005, we began engineering and design work to construct a 190-mile, 12-inch NGL pipeline that will have the capacity to move up to 67 MBPD of mixed NGLs bi-directionally between Skellytown, Texas and Conway, Kansas and an additional 48 MBPD from Skellytown, Texas to Hobbs, New Mexico. Construction of this pipeline began in the spring of 2006 and is expected to cost $90 million and be placed in service by March 2007.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. During the three months ended June 30, 2006, we spent approximately $13.1 million to comply with these programs, of which $8.4 million was recorded as an operating expense and the remaining $4.7 million was capitalized. We spent approximately $31.6 million to comply with these programs during the six months ended June 30, 2006 of which $14.3 million was recorded as an operating expense and the remaining $17.3 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $37.4 million for the remainder 2006. Our forecast is net of certain costs we expect to recover from El Paso in connection with an indemnification agreement. In May 2006, we recovered $13.7 million from El Paso related to our 2005 expenditures and expect to recover $9.7 million related to our first and second quarter 2006 expenditures, which leaves a remainder of $26.8 million reimbursable by El Paso for 2006 and 2007 pipeline integrity costs.

RESULTS OF OPERATIONS

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-generally accepted accounting principle (non-GAAP) financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The financial measure calculated using accounting principles generally accepted in the United States of America (GAAP) most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

For additional information regarding our business segments, please read Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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Selected Price and Volumetric Data

The following table presents selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2005:

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2005									
1st Quarter	$ 6.27	$49.68	$0.52	$0.79	$0.98	$1.00	$1.14	$0.45	$0.39
2nd Quarter	$ 6.74	$53.09	$0.52	$0.82	$0.98	$1.01	$1.16	$0.37	$0.30
3rd Quarter	$ 8.53	$63.08	$0.69	$0.97	$1.14	$1.26	$1.36	$0.37	$0.33
4th Quarter	$13.00	$60.03	$0.76	$1.06	$1.27	$1.34	$1.36	$0.50	$0.44
Average for Year	$ 8.64	$56.47	$0.62	$0.91	$1.09	$1.15	$1.26	$0.42	$0.37
2006									
1st Quarter	$ 9.01	$63.35	$0.57	$0.94	$1.20	$1.27	$1.38	$0.45	$0.40
2nd Quarter	$ 6.80	$70.53	$0.68	$1.05	$1.22	$1.26	$1.52	$0.50	$0.44
Average for Year	$ 7.91	$66.94	$0.63	$1.00	$1.21	$1.27	$1.45	$0.48	$0.42

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (OPIS) and Chemical Market Associates, Inc. (CMAI). The natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests, and reflect the periods in which we owned an interest in such operations.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,559	1,511	1,490	1,461
NGL fractionation volumes (MBPD)	308	327	282	332
Equity NGL production (MBPD) (1)	61	84	59	84
Fee-based natural gas processing (MMcf/d)	2,465	2,001	2,138	2,009
Onshore Natural Gas Pipelines & Services, net:				

Natural gas transportation volumes (BBtus/d)	5,907	5,985	5,979	5,866
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,523	2,156	1,500	2,004
Crude oil transportation volumes (MBPD)	161	151	137	139
Platform gas treating (Mcf/d)	158	319	158	317
Platform oil treating (MBPD)	18	7	12	8
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	83	84	84	75
Propylene fractionation volumes (MBPD)	56	56	54	55
Octane additive production volumes (MBPD)	9	8	7	4
Petrochemical transportation volumes (MBPD)	93	72	90	73
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,813	1,734	1,717	1,673
Natural gas transportation volumes (BBtus/d)	7,430	8,141	7,479	7,870
Equivalent transportation volumes (MBPD) (2)	3,768	3,877	3,685	3,744

(1) Volumes for the first and second quarters of 2005 have been revised to incorporate asset-level definitions of equity NGL production volumes.

(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

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Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues	$3,517,853	$2,671,768	$6,767,927	$5,227,290
Operating costs and expenses	3,323,585	2,530,133	6,370,448	4,913,777
General and administrative costs	16,235	18,710	29,975	33,403
Equity in income of unconsolidated affiliates	8,012	2,581	12,041	10,860
Operating income	186,045	125,506	379,545	290,970
Interest expense	56,333	56,746	114,410	110,159
Net income	126,295	70,659	260,072	179,915

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 69% and 66% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 68% and 66% for the six months ended June 30, 2006 and 2005, respectively. Revenues from the sale and marketing of petrochemical products within the Petrochemical Services segment accounted for 11% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 11% and 12% for the six months ended June 30, 2006 and 2005, respectively. Revenues from the sale and marketing of natural gas using onshore assets accounted for 8% and 9% of total consolidated revenues for the three months ended June 30, 2006 and 2005, and 9% and 8% for the six months ended June 30, 2006 and 2005, respectively.

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Gross operating margin by segment:				
NGL Pipelines & Services	$146,414	$120,328	$317,364	$273,632
Onshore Natural Gas Pipelines & Services	86,651	84,903	183,454	164,261
Offshore Pipelines & Services	20,515	22,034	37,767	45,258
Petrochemical Services	57,044	18,610	84,562	37,938
Total segment gross operating margin	$310,624	$245,875	$623,147	$521,089

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for taxes, minority interest and cumulative effect of change in accounting principle, please read *Other Items* included within this Item 2.

Comparison of Three Months Ended June 30, 2006 with Three Months Ended June 30, 2005

Revenues for the second quarter of 2006 were $3.5 billion compared to $2.7 billion for the second quarter of 2005. The quarter-to-quarter increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in the second quarter of 2006 relative to the same period in 2005. These differences accounted for an $820.6 million increase in consolidated revenues associated with our marketing activities.

Operating costs and expenses were $3.3 billion for the second quarter of 2006 versus $2.5 billion for the second quarter of 2005. The quarter-to-quarter increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $754.4 million quarter-to-quarter as a result of higher energy commodity prices.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.04 per gallon during the second quarter of 2006 versus $0.81 per gallon during the second quarter of 2005 a quarter-to-quarter increase of 28%. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary hub of the domestic NGL industry. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $6.80 per MMBtu during the second quarter of 2006 versus $6.74 per MMBtu during the second quarter of 2005. For additional historical energy commodity pricing information, please see the table on page 42.

Equity earnings from unconsolidated affiliates were $8 million for the second quarter of 2006 compared to $2.6 million for the second quarter of 2005, an increase of $5.4 million quarter-to-quarter. Equity earnings for the second quarter of 2005 included a one-time charge of $11.5 million for costs associated with refinancing project finance debt of Cameron Highway Oil Pipeline Company (Cameron Highway), which was partially offset by a $5.1 million benefit associated with the settlement of a transportation contract dispute.

Operating income for the second quarter of 2006 was $186 million compared to $125.5 million for the second quarter of 2005. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $60.5 million increase in operating income quarter-to-quarter.

Interest expense decreased $0.4 million quarter-to-quarter. Although outstanding debt balances and interest rates were higher during the second quarter of 2006 relative to the second quarter of 2005, significant amounts of interest are being capitalized as a result of borrowings to finance our capital spending program. Capitalized interest amounts were $12.4 million for the second quarter of 2006 compared to $3.2 million for the second quarter of 2005.

Provision for income taxes increased $7.3 million quarter-to-quarter primarily due to the new Texas margin tax. For more information regarding the Texas margin tax, please see *Other Items* included within this Item 2.

As a result of the items noted in previous paragraphs, our consolidated net income increased $55.6 million to $126.3 million for the second quarter of 2006 compared to $70.7 million for the second quarter of 2005.

The following information highlights the significant quarter-to-quarter variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $146.4 million for the second quarter of 2006 compared to $120.3 million for the second quarter of 2005. Improved results from our natural gas processing and related NGL marketing business accounted for substantially all of the $26.1 million increase in gross operating margin. Strong demand for NGLs in the second quarter of 2006 led to higher processing margins and increased volumes processed under fee-based contracts. Gross operating margin from our natural gas processing and related NGL marketing business was $80.8 million for the second quarter of 2006 compared to $55.7 million for the same quarter in 2005. Fee-based processing volumes increased to 2.5 Bcf/d during the second quarter of 2006 from 2 Bcf/d during the second quarter of 2005. Lastly, gross operating margin from natural gas processing for the second quarter of 2006 includes $2.3 million from the Pioneer plant we acquired from TEPPCO in March 2006.

Gross operating margin from NGL pipelines and storage was $50.7 million for the second quarter of 2006 compared to $48.4 million for the second quarter of 2005. Total NGL transportation volumes increased to 1,559 MBPD during the second quarter of 2006 from 1,511 MBPD during the same quarter of 2005. The $2.3 million quarter-to-quarter increase in gross operating margin is attributable to higher NGL storage volumes and contributions from storage assets we acquired in July 2005. The increase in gross operating margin from our NGL storage business was partially offset by a $4.6 million increase in pipeline integrity costs quarter-to-quarter.

Gross operating margin from NGL fractionation was $14.9 million for the second quarter of 2006 compared to $16.2 million for the second quarter of 2005. Fractionation volumes decreased from 327 MBPD during the second quarter of 2005 to 308 MBPD during the second quarter of 2006. The quarter-to-quarter decrease in gross operating margin and fractionation volumes is largely due to downtime and start-up costs associated with the completion of an expansion project at our Mont Belvieu NGL fractionator during the second quarter of 2006.

Segment gross operating margin for the second quarter of 2006 also includes $2 million of income resulting from business interruption recoveries attributable to Hurricane Ivan. These recoveries relate to our South Louisiana assets that were affected by this storm in 2004.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $86.7 million for the second quarter of 2006 compared to $84.9 million for the second quarter of 2005. Higher transportation revenues on our Texas Intrastate System contributed to a $4.6 million quarter-to-quarter increase in segment gross operating margin. An increase in drilling activity in the Permian and San Juan basins benefited our assets during the second quarter of 2006. Our gathering systems in the Permian basin experienced higher transportation volumes and natural gas sales margins quarter-to-quarter. As drilling activity increased, our San Juan Gas Gathering System started to benefit from its system optimization project, which was completed in early 2006. Collectively, gross operating margin from our San Juan and Permian basin gathering systems increased $3.2 million quarter-to-quarter. Segment gross operating margin for the second quarter of 2006 includes approximately $4 million of costs associated with the inspection, repair and maintenance of three storage caverns at our Wilson natural gas storage facility in Texas. Our total onshore natural gas transportation volumes were 5,907 BBtu/d during the second quarter of 2006 compared to 5,985 BBtu/d for the second quarter of 2005.

We completed the expansion of our 30-inch West Texas pipeline system during the second quarter of 2006 and acquired the Cerrito natural gas gathering systems in July 2006. Our 30-inch West Texas pipeline system provides us 120 MMcf/d of incremental natural gas transportation capacity. This pipeline will transport production from the Barnett Shale and Permian basin areas to markets in Central Texas and the Gulf Coast. Our acquisition of the Cerrito natural gas gathering systems provides us, among other things, with life of lease dedications related to significant natural gas fields located in South Texas.

Offshore Pipelines & Services. Gross operating margin from this business segment was $20.5 million for the second quarter of 2006 compared to $22 million for the second quarter of 2005. In general, offshore operations in the Gulf of Mexico continue to be impacted (albeit to a lesser degree at this time) by the lingering effects of last year s hurricanes. Producers are working to restore production to at or near pre-hurricane levels and remain committed to exploration and production activities in the Gulf of Mexico, including its deepwater areas. As a result of industry losses last year, insurance costs for offshore operations have increased dramatically. Our insurance costs for these assets were $6 million for the second quarter of 2006 compared to $0.9 million for the second quarter of 2005.

Gross operating margin from our offshore crude oil pipelines was a positive $5.8 million for the second quarter of 2006 versus a loss of $6.5 million for the second quarter of 2005. Our Marco Polo and Poseidon Oil Pipelines posted higher crude oil transportation volumes during the second quarter of 2006 due to increased production activity. Gross operating margin from the Marco Polo and Poseidon Oil Pipelines improved $2.1 million quarter-to-quarter. Our Constitution Oil Pipeline, which was placed in-service during the first quarter of 2006, contributed $2.5 million to segment gross operating margin during the second quarter of 2006. Gross operating margin from Cameron Highway improved $8.3 million quarter-to-quarter. Cameron Highway s results for the second quarter of 2005 included a one-time charge of $11.5 million for costs associated with the refinancing of its project finance debt. Offshore crude oil transportation volumes were 161 MBPD during the second quarter of 2006 versus 151 MBPD during the second quarter of 2005.

Gross operating margin from our offshore natural gas pipelines was $6.5 million for the second quarter of 2006 compared to $17.3 million for the second quarter of 2005. Offshore natural gas transportation volumes were 1,523 BBtu/d during the second quarter of 2006 versus 2,156 BBtu/d during the second quarter of 2005. The decrease in gross operating margin and overall transportation volumes is primarily due to last year s hurricanes. Also, gross operating margin attributable to this group of assets for the second quarter of 2005 includes a one-time $5.1 million benefit resulting from the settlement of a transportation contract dispute. Gross operating margin for the second quarter of 2006 includes $1.8 million from the Constitution Natural Gas Pipeline, which was placed in service during the first quarter of 2006.

Our Phoenix Gas Gathering System returned to service during the second quarter of 2006 and is currently operating in excess of pre-hurricane rates. Volumes are expected to increase on our Viosca Knoll Gas Gathering System during the third quarter of 2006, as new production from the Matterhorn field is transported to processing facilities. Also, during the second quarter of 2006, we made significant progress on our Independence Hub and Trail project, which is scheduled for completion and first production during the first quarter of 2007.

Gross operating margin from our offshore platforms was $8.2 million for the second quarter of 2006 compared to $11.2 million for the second quarter of 2005. The decrease in gross operating margin quarter-to-quarter is primarily due to last year s hurricanes. Equity earnings from Deepwater Gateway, L.L.C., which owns the Marco Polo platform, increased $1.9 million quarter-to-quarter primarily due to higher processing volumes.

Petrochemical Services. Gross operating margin from this business segment was $57 million for the second quarter of 2006 compared to $18.6 million for the second quarter of 2005. The $38.4 million quarter-to-quarter increase in gross operating margin is primarily due to improved results from our octane enhancement business. Gross operating margin from this business was a positive $20.5 million for the second quarter of 2006 compared to a loss of $6.1 million for the second quarter of 2005. The $26.6 million quarter-to-quarter increase is attributable to strong seasonal demand for isooctane as a motor gasoline additive. Isooctane, a high octane, low vapor pressure motor gasoline additive, complements the increasing use of ethanol, which has a high vapor pressure. Our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from our propylene fractionation and pipeline activities was $16 million for the second quarter of 2006 versus $7.4 million for the second quarter of 2005. The quarter-to-quarter increase in gross operating margin of $8.6 million is primarily due to higher propylene sales margins and pipeline volumes. The second quarter of 2006 benefited from the use of a new pipeline, which we completed in 2005, that transports refinery-grade propylene from Texas City, Texas to our propylene fractionation complex at Mont Belvieu, Texas. Petrochemical transportation volumes were 93 MBPD during the second quarter of 2006 compared to 72 MBPD during the second quarter of 2005.

Gross operating margin from butane isomerization was $20.5 million for the second quarter of 2006 compared to $17.3 million for the second quarter of 2005. The quarter-to-quarter increase of $3.2 million is primarily due to higher commodity sales prices.

Comparison of Six Months Ended June 30, 2006 with Six Months Ended June 30, 2005

Revenues for the first six months of 2006 were $6.8 billion compared to $5.2 billion for the first six months of 2005. The period-to-period increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices during the first six months of 2006 relative to the 2005 period. These differences accounted for a $1.5 billion increase in consolidated revenues associated with our marketing activities.

Operating costs and expenses were $6.4 billion for the first six months of 2006 compared to $4.9 billion for the first six months of 2005. The period-to-period increase in consolidated operating costs and expenses is primarily due to an increase in the costs of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $1.2 billion period-to-period as a result of higher energy commodity prices.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.99 per gallon for the six months ended June 30, 2006 versus $0.80 per gallon during the first six months of 2005 a period-to-period increase of 24%. The Henry Hub market price for natural gas averaged $7.91 per MMBtu for the six months ended June 30, 2006 versus $6.51 per MMBtu during the 2005 period. For additional historical energy commodity pricing information, please see the table on page 42.

Equity earnings from unconsolidated affiliates were $12 million for the first six months of 2006 versus $10.9 million for the first six months of 2005, an increase of $1.1 million period-to-period. Equity earnings for the first six months of 2005 include a one-time charge of $11.5 million for costs associated with the refinancing of Cameron Highway s project finance debt, which was partially offset by a $5.1 million benefit associated with the settlement of a transportation contract dispute. Equity earnings from Venice Energy Services Company, LLC (VESCO) decreased $2 million period-to-period attributable to facility down-time and repair costs caused by the 2005 hurricanes.

Interest expense increased to $114.4 million for the first six months of 2006 from $110.2 million for the first six months of 2005. Although outstanding debt balances and interest rates were higher during the first six months of 2006 relative to the 2005 period, significant amounts of interest are being capitalized as a result of borrowings to finance our capital spending program. Capitalized interest amounts were $21.6 million for the first six months of 2006 compared to $7.6 million for the first six months of 2005. Provision for income taxes increased $8.4 million period-to-period primarily due to the new Texas margin tax.

As a result of the items noted in previous paragraphs, our consolidated net income increased $80.2 million to $260.1 million for the six months ended June 30, 2006 compared to $179.9 million for the 2005 period. The first six months of 2006 includes a $1.5 million benefit related to the cumulative effect of a change in accounting principle resulting from our adoption of Statement of Financial Accounting Standards (SFAS) 123(R) on January 1, 2006. For additional information regarding this cumulative effect adjustment, please read Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

The following information highlights the significant period-to-period variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $317.4 million for the first six months of 2006 compared to $273.6 million for the first six months of 2005. Improved results from our natural gas processing and related NGL marketing business and our NGL pipelines and storage business accounted for substantially all of the $43.8 million increase in gross operating margin. Strong demand for NGLs during 2006 led to higher processing margins and increased volumes processed under fee-based contracts. Gross operating margin from our natural gas processing and related NGL marketing business increased to $165.8 million for the first six months of 2006 from $139.3 million for the first six months of 2005. Fee-based processing volumes increased to 2.1 Bcf/d during the first six months of 2006 from 2 Bcf/d during the first six months of 2005. Lastly, gross operating margin from natural gas processing for the first six months of 2006 includes $2.3 million from the Pioneer plant we acquired from TEPPCO in March 2006.

Gross operating margin from NGL pipelines and storage was $119.7 million for the first six months of 2006 compared to $100.4 million for the first six months of 2005. Total NGL transportation volumes increased to 1,490 MBPD for the first six months of 2006 from 1,461 MBPD for the first six months of 2005. The $19.3 million period-to-period increase in gross operating margin is attributable to higher pipeline transportation, NGL storage and export volumes at certain of our facilities and contributions from acquired or consolidated assets, particularly that generated by the Dixie NGL Pipeline. The increase in gross operating margin was partially offset by a $5.7 million increase in pipeline integrity costs period-to-period.

Gross operating margin from NGL fractionation was $31.9 million for the first six months of 2006 compared to $33.8 million for the first six months of 2005. Fractionation volumes decreased from 332 MBPD during the first six months of 2005 to 282 MBPD during the first six months of 2006. The period-to-period decrease in gross operating margin and fractionation volumes is largely due to our Mont Belvieu and Norco NGL fractionators. Our Mont Belvieu NGL fractionator experienced downtime and start-up costs associated with the completion of its expansion project during the first six months of 2006. Our Norco NGL fractionator, which returned to normal operating rates in the second quarter of 2006, suffered a reduction of processing volumes due to the effects of Hurricane Katrina.

Segment gross operating margin from this business segment for the 2006 period also includes $10.3 million of income resulting from business interruption recoveries attributable to Hurricane Ivan. These recoveries relate to our South Louisiana assets that were affected by this storm in 2004.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $183.5 million for the first six months of 2006 compared to $164.3 million for the first six months of 2005. Higher transportation revenues on our Texas Intrastate System contributed to a $10.4 million increase in segment gross operating margin period-to-period. An increase in drilling activity in the Permian and San Juan basins benefited our assets during the first six months of 2006. Our gathering systems in the Permian basin experienced higher transportation volumes and natural gas sales margins period-to-period. Collectively, gross operating margin from our San Juan and Permian basin gathering systems increased $9.7 million period-to-period. Segment gross operating margin for the first six months of 2006 includes approximately $4 million of costs associated with the inspection, repair and maintenance of three storage caverns at our Wilson natural gas storage facility. Our total onshore natural gas transportation volumes were 5,979 BBtu/d during the first six months of 2006 compared to 5,866 BBtu/d during the first six months of 2005.

Offshore Pipelines & Services. Gross operating margin from this business segment was $37.8 million for the first six months of 2006 compared to $45.3 million for the first six months of 2005. In general, offshore operations in the Gulf of Mexico continue to be impacted (albeit to a lesser degree at this time) by the lingering effects of last year s hurricanes. As a result of industry losses last year, insurance costs for offshore operations have increased dramatically. Our insurance costs for the first six months of 2006 increased $5.2 million over those recorded during the first six months of 2005.

Gross operating margin from our offshore crude oil pipelines was a positive $7.4 million for the first six months of 2006 versus a loss of $3.6 million for the first six months of 2005. Our Marco Polo Pipeline posted higher crude oil transportation volumes during the first six months of 2006 due to increased production activity. Gross operating margin from the Marco Polo Pipeline improved $2.1 million period-to-period. Our Constitution Oil Pipeline, which was placed in-service during the first quarter of 2006, contributed $3.4 million to segment gross operating margin during the first six months of 2006. Gross operating margin from Cameron Highway improved $7.1 million period-to-period. Cameron Highway s results for the first six months of 2005 included a one-time charge of $11.5 million for costs associated with the refinancing of its project finance debt. Offshore crude oil transportation volumes were 137 MBPD during the first six months of 2006 versus 139 MBPD during the first six months of 2005.

Gross operating margin from our offshore natural gas pipelines was $13.7 million for the first six months of 2006 compared to $27.5 million for the first six months of 2005. Offshore natural gas transportation volumes were 1,500 BBtu/d during the first six months of 2006 versus 2,004 BBtu/d during the first six months of 2005. The decrease in gross operating margin and overall transportation volumes is primarily due to last year s hurricanes. Also, gross operating margin attributable to this group of assets for the first six months of 2005 includes a one-time $5.1 million benefit resulting from the settlement of a transportation contract dispute. Gross operating margin for the first six months of 2006 includes $2.1 million from the Constitution Natural Gas Pipeline, which was placed in service during the first quarter of 2006.

Gross operating margin from our offshore platforms and services business was $16.7 million for the first six months of 2006 compared to $21.4 million for the first six months of 2005. The decrease in gross operating margin period-to-period is primarily due to last year s hurricanes. Equity earnings from Deepwater Gateway, L.L.C., which owns the Marco Polo platform, increased $3.5 million period-to-period primarily due to higher processing volumes.

Petrochemical Services. Gross operating margin from this business segment was $84.6 million for the first six months of 2006 compared to $37.9 million for the first six months of 2005. The $46.7 million period-to-period increase in gross operating margin is primarily due to improved results from our octane enhancement business. Gross operating margin from this business was a positive $9.4 million for the first six months of 2006 compared to a loss of $15.1 million for the first six months of 2005. The $24.5 million period-to-period increase is attributable to strong seasonal demand for isooctane as a motor gasoline additive during the second quarter of 2006. Also, our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from propylene fractionation was $36.5 million for the first six months of 2006 versus $22.2 million for the first six months of 2005. The period-to-period increase in gross operating margin of $14.3 million is primarily due to higher propylene sales margins and pipeline transportation volumes. Petrochemical transportation volumes were 90 MBPD during the first six months of 2006 compared to 73 MBPD during the first six months of 2005.

Gross operating margin from butane isomerization was $38.6 million for the first six months of 2006 compared to $30.8 million for the first six months of 2005. The period-to-period increase of $7.8 million is largely due to increased demand for motor gasoline additives.

Significant Risks and Uncertainties Hurricanes

The following is a discussion of the general status of insurance claims related to significant storm events that affected our assets in 2004 and 2005. To the extent we include estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the GulfTerra Merger) included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During the first quarter of 2006, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million in late 2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the first quarter of 2006, we received claim proceeds of $10.2 million, and in April 2006 we received an additional $2 million. We expect to receive additional receipts of approximately $5.5 million during the third quarter of 2006. To the extent we receive cash proceeds from business interruption insurance claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection, evaluation and repair of property damage to our facilities is continuing. To the extent that insurance proceeds from property damage claims do not cover our estimated recoveries (in excess of the $5 million of insurance deductibles we expensed during the third quarter of 2005), such shortfall will be charged to earnings when realized. We recorded $63.5 million of estimated recoveries from property damage claims arising from Hurricanes Katrina and Rita, based on amounts expended through June 30, 2006. In July 2006, we received $1.2 million of physical damage proceeds, and we anticipate receiving an additional $9.3 million of physical damage proceeds in the third quarter of 2006. In July 2006, we received $4.9 million of business interruption proceeds, and we anticipate receiving an additional $41.6 million of business interruption proceeds during the third quarter of 2006. To the extent we receive cash proceeds from business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including cash flows from operating activities, borrowings under commercial bank credit facilities and the issuance of additional equity and debt securities. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At June 30, 2006, we had $24.5 million of unrestricted cash on hand and approximately $673.4 million of available credit under our Operating Partnership s Multi-Year Revolving Credit Facility. We had approximately $4.9 billion in principal outstanding under various consolidated debt obligations at June 30, 2006.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

For additional information regarding our growth strategy, please read *Capital Spending* included within this Item 2.

Credit Ratings

At July 31, 2006, the credit ratings of our Operating Partnership s debt securities were Baa3 with a stable outlook as rated by Moody s Investor Services; BBB- with a stable outlook as rated by Fitch Ratings; and BB+ with a positive outlook as rated by Standard and Poor s.

Based on the characteristics of the fixed/floating unsecured junior subordinated notes that the Operating Partnership issued in July 2006, the rating agencies assigned partial equity treatment to the notes. Moody s Investor Services and Standard and Poor s each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

Registration Statements and Equity and Debt Offerings

From time-to-time, we issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) registering the issuance of up to $4 billion of equity and debt securities. After taking into account the past issuance of securities under this universal registration statement, we can issue approximately $2.7 billion of additional securities under this registration statement as of July 31, 2006.

In March 2006, we sold 18,400,000 common units (including an over-allotment amount of 2,400,000 common units) to the public at an offering price of $23.90 per unit. Net proceeds from this offering, including Enterprise Products GP s proportionate net capital contribution of $8.6 million, were approximately $430 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $18.3 million. The net proceeds from this offering, including Enterprise Products GP s proportionate net capital contribution, were used to temporarily reduce indebtedness outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility.

In July 2006, the Operating Partnership sold $300 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes A). The Operating Partnership used the proceeds from this issuance to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Junior Notes A mature in August 2066 and will bear interest from July 2006 to August 2016 at an annual rate of 8.375%, and thereafter at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%.

In July 2006, we issued approximately 7.1 million of our common units as partial consideration for our acquisition of natural gas pipeline assets located in South Texas. We are obligated to file a registration statement with the SEC for the resale of these common units. See *Capital Spending* included within this Item 2 for additional information regarding this acquisition.

Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report. The following table summarizes our consolidated debt obligations at the dates indicated (dollars in thousands):

	June 30, 2006	**December 31, 2005**
Operating Partnership debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011[1,2]	$ 530,000	$ 490,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Dixie Revolving Credit Facility, variable rate, due June 2007	10,000	17,000
Debt obligations assumed from GulfTerra	5,068	5,068
Total principal amount	4,899,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value[3]	(77,667)	(32,287)
Long-term debt	$4,821,401	$4,833,781
Standby letters of credit outstanding	$ 46,558	$ 33,129

(1)

In June 2006, the Operating Partnership executed a second amendment (the Second Amendment) to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to the remaining $48 million in commitments mature in October 2010.

(2) We generated net proceeds of $430 million in March 2006 in connection with the sale of 18,400,000 of our common units in an underwritten equity offering. Subsequently,

this amount was contributed to the Operating Partnership, which, in turn, used this amount to temporarily reduce debt outstanding under its Multi-Year Revolving Credit Facility.

(3) The June 30, 2006 amount includes $64 million related to fair value hedges and $13.7 million in net unamortized discounts. The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. For additional information regarding our fair value hedges, please read Item 3 of this quarterly report.

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The following table summarizes the debt obligations of our unconsolidated affiliates (on a 100% basis to the joint venture) at June 30, 2006 and our ownership interest in each entity on that date (dollars in thousands):

	Our Ownership Interest	Total
Cameron Highway	50.0%	$415,000
Poseidon Oil Pipeline Company, L.L.C. (Poseidon)	36.0%	92,000
Evangeline Gas Pipeline Company, L.P.	49.5%	30,650
Total		$537,650

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the letters of credit required to be issued by the Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

In May 2006, Poseidon amended its revolving credit facility, which, among other things, decreased the availability to $150 million from $170 million, extended the maturity date from January 2008 to May 2011 and lowered the borrowing rate.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, please see the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2006	2005
Net cash provided from operating activities	$571,325	$117,837
Net cash used in investing activities	689,787	570,449
Net cash provided by financing activities	100,888	461,101

The following information highlights the significant quarter-to-quarter variances in our cash flow amounts:

Comparison of Six Months Ended June 30, 2006 with Six Months Ended June 30, 2005

Operating activities. Net cash provided from operating activities was $571.3 million for the first six months of 2006 compared to $117.8 million for the first six months of 2005. The $453.5 million period-to-period increase in net cash provided from operating activities is primarily due to:

§ Net income adjusted for all non-cash items and the net effects of changes in operating accounts increased $472 million period-to-period primarily due to the timing of cash receipts and payments during the periods.

§ Distributions received from unconsolidated affiliates decreased by $18.6 million period-to-period primarily due to (i) a decrease in distributions from VESCO resulting from facility down-time and repair costs in 2006 caused by damage inflicted by Hurricane Katrina, (ii) our receipt of a special distribution from Deepwater Gateway, L.L.C. (Deepwater Gateway) in March 2005 in connection with the repayment of its term loan and (iii) our receipt of a $5.1 million distribution

from Neptune Pipeline Company, L.L.C. during 2005 associated with the resolution of a transportation contract dispute.

Investing activities. Cash used in investing activities was $689.8 million for the first six months of 2006 compared to $570.4 million for the first six months of 2005. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) increased $131.7 million period-to-period primarily due to cash payments associated with our projects in the Rocky Mountains and Gulf of Mexico. In addition, during the first six months of 2006 we spent $97.8 million in connection with our Jonah expansion project. Our cash outlays for asset purchases and business combinations were $38.1 million for the first six months of 2006 versus $181.1 million for the first six months of 2005. For additional information related to our capital spending program, please read *Capital Spending* included within this Item 2.

Our investments in unconsolidated affiliates decreased from $80.7 million for the first six months of 2005 to $14.1 million for the first six months of 2006. In March 2005, we contributed $72 million to Deepwater Gateway to fund our share of the repayment of its term loan.

Cash inflows related to investing activities for the first six months of 2005 include cash receipts of (i) $42.1 million from the sale of our investment in Starfish Pipeline Company, LLC, which was required by the Federal Trade Commission in order to gain its approval for the GulfTerra Merger and (ii) $47.5 million related to a return of our investment in Cameron Highway associated with the refinancing of its project debt in June 2005.

Financing activities. Cash provided by financing activities was $100.9 million for the first six months of 2006 compared to $461.1 million for the first six months of 2005. We had net borrowings under our debt agreements of $33 million during the first six months of 2006 versus $271.3 million during the first six months of 2005. We used $430 million of net proceeds from our March 2006 equity offering to reduce debt outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility. In addition, during 2006 we used borrowings under our Operating Partnership s Multi-Year Revolving Credit Facility to fund our capital spending program.

During the first six months of 2005, our Operating Partnership issued an aggregate of $1 billion in senior notes, the proceeds of which were used to repay $350 million due under its Senior Notes A, to temporarily reduce amounts outstanding under its other bank credit facilities and for general partnership purposes, including capital expenditures and business combinations. Also during the first six months of 2005, the Operating Partnership repaid $242.2 million then outstanding under its 364-Day Acquisition Credit Facility (which was used to finance elements of the GulfTerra Merger) using proceeds generated from our February 2005 equity offering.

Net proceeds from the issuance of limited partner interests were $453.5 million for the first six months of 2006 compared to $525.2 million for the first six months of 2005. We issued 19,295,836 common units during the first six months of 2006 and 19,176,810 common units during the first six months of 2005. Net proceeds from underwritten equity offerings were $430 million during the first six months of 2006 reflecting the sale of 18,400,000 units and $456.7 million during the first six months of 2005 reflecting the sale of 17,250,000 units. We used net proceeds from these underwritten offerings to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. Our distribution reinvestment program and related plan generated net proceeds of $21.9 million for the first six months of 2006 and $49.4 million for the first six months of 2005. We used net proceeds from these offerings for general partnership purposes.

Cash distributions to partners increased from $346.6 million during the first six months of 2005 to $400.5 million during the first six months of 2006 primarily due to an increase in our common units outstanding and our quarterly cash distribution rates. Cash contributions from minority interests were $19 million for the first six months of 2006 compared to $23.6 million for the first six months of 2005. These amounts represent contributions from our joint venture partner in the Independence Hub project.

CONTRACTUAL OBLIGATIONS

Since December 31, 2005, scheduled maturities of long-term debt increased $33 million primarily due to borrowings under our Operating Partnership s Multi-Year Revolving Credit Facility to fund our capital spending program, offset by the application of net proceeds generated by our equity offering in March 2006 to temporarily reduce debt outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility. For additional information regarding our debt obligations, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report. Also, we renewed our lease of the Wilson natural gas storage facility for an additional 20-year period during the first quarter of 2006. For additional information regarding our commitments under this significant lease, please read Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Other than the items noted in the previous paragraph, there have been no significant changes with regard to our material contractual obligations (outside of the ordinary course of business) since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

OFF-BALANCE SHEET ARRANGEMENTS

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the face amount of the letters of credit required to be issued by our Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

In May 2006, Poseidon amended its revolving credit facility to, among other things, reduce commitments from $170 million to $150 million, extend the maturity date from January 2008 to May 2011 and lower the borrowing rate.

Other than the amendments discussed above, there have been no significant changes with regard to our off-balance sheet arrangements since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

RECENT ACCOUNTING DEVELOPMENTS

In March 2006, we adopted the provisions of Emerging Issues Task Force (EITF) 04-13, *Accounting for Purchases and Sale of Inventory With the Same Counterparty.* This accounting guidance requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. This guidance was effective April 1, 2006, and our adoption of this guidance had no impact on our financial position, results of operations or cash flows.

In January 2007, we will adopt the provisions of 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).* This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. This guidance specifically applies to taxes imposed by governmental authorities on revenue-producing transactions between sellers and customers (gross receipts taxes are excluded). This guidance is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis.

Also in January 2007, we will adopt Statement of Financial Accounting Standards (SFAS) 155, *Accounting for Certain Hybrid Financial Instruments*. This accounting standard amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, amends SFAS 140, *Accounting for*

Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, and resolves issues addressed in Statement 133 Implementation Issue D1, *Application of Statement 133 to Beneficial Interests to Securitized Financial Assets*. A hybrid financial instrument is one that embodies both an embedded derivative and a host contract. For certain hybrid financial instruments, SFAS 133 requires an embedded derivative instrument be separated from the host contract and accounted for as a separate derivative instrument. SFAS 155 amends SFAS 133 to provide a fair value measurement alternative for certain hybrid financial instruments that contain an embedded derivative that would otherwise be recognized as a derivative separately from the host contract. For hybrid financial instruments within its scope, SFAS 155 allows the holder of the instrument to make a one-time, irrevocable election to initially and subsequently measure the instrument in its entirety at fair value instead of separately accounting for the embedded derivative and host contract. We are evaluating the effect of this recent guidance, which is effective January 1, 2007 for our partnership.

CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect.

In general, there have been no significant changes in our critical accounting policies since December 31, 2005. For a detailed discussion of these policies, please read *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies* in our annual report on Form 10-K for 2005. The following describes the estimation risk underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts on a going forward basis.

At June 30, 2006 and December 31, 2005, the net book value of our property, plant and equipment was $9 billion and $8.7 billion, respectively. For additional information regarding our property, plant and equipment, please read Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value for the investment other than a temporary decline. Measuring the potential impairment of such assets and investments involves the estimation of future cash flows to be derived from the asset being tested. Our estimates of such cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of asset or asset group; and salvage values. A significant change in these underlying assumptions could result in our recording an impairment charge.

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Amortization methods and estimated useful lives of qualifying intangible assets

In general, our intangible asset portfolio consists primarily of the estimated values assigned to certain customer relationships and customer contracts. We amortize the customer relationship values using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. We amortize the customer contract intangible assets over the estimated remaining economic life of the underlying contract. A change in the estimates we use to determine amortization rates of our intangible assets (e.g., oil and natural gas production curves, remaining economic life of the contracts, etc.) could result in a material change in the amortization expense we record and the carrying value of our intangible assets.

At June 30, 2006 and December 31, 2005, the carrying value of our intangible asset portfolio was $909.3 million and $913.6 million, respectively. For additional information regarding our intangible assets, please read Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values and is primarily comprised of $387.1 million associated with the GulfTerra Merger. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit s fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Our estimates of such prospects (i.e., cash flows) are based on a number of assumptions including anticipated margins and volumes of the underlying assets or asset group. A significant change in these underlying assumptions could result in our recording an impairment charge.

At June 30, 2006 and December 31, 2005, the carrying value of our goodwill was $494 million. For additional information regarding our goodwill, please read Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our revenue recognition policies and use of estimates for revenues and expenses

Our use of certain estimates for revenues and operating costs and other expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing of compiling actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves.

At June 30, 2006 and December 31, 2005, we had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS 5 *Accounting for Contingencies* and Financial Accounting Standards Board Interpretation (FIN) 14, *Reasonable Estimation of the Amount of a Loss*, we recorded our best estimate of these remediation activities.

Natural gas imbalances

Natural gas imbalances result when customers physically deliver a larger or smaller quantity of natural gas into our pipelines than they take out. In general, we value such imbalances using a twelve-month moving average of natural gas prices, which we believe is reasonable given that the actual settlement dates for such imbalances are generally not known. As a result, significant changes in natural gas prices between reporting periods may impact our estimates.

At June 30, 2006 and December 31, 2005, our imbalance receivables were $77.9 million and $89.4 million, respectively, and are reflected as a component of accounts receivable. At June 30, 2006 and December 31, 2005, our imbalance payables were $58.2 million and $80.5 million, respectively, and are reflected as a component of accrued gas payables.

SUMMARY OF RELATED PARTY TRANSACTIONS

In accordance with SFAS 57, *Related Party Disclosures*, we have identified our material related party revenues, costs and expenses. The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Revenues from consolidated operations				
EPCO and affiliates	$ 33,448	$ 2	$ 39,080	$ 286
Unconsolidated affiliates	79,986	80,946	164,429	138,855
Total	$113,434	$80,948	$203,509	$139,141
Operating costs and expenses				
EPCO and affiliates	$ 71,105	$64,991	$166,062	$123,994
Unconsolidated affiliates	7,904	3,898	14,590	10,466
Total	$ 79,009	$68,889	$180,652	$134,460
General and administrative expenses				
EPCO and affiliates	$ 10,830	$11,119	$ 21,838	$ 20,794

For additional information regarding our related party transactions identified in accordance with GAAP, please read Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, LLC for NGL transportation, storage and fractionation services.

At June 30, 2006, other assets includes $106.9 million related to our Jonah expansion project with TEPPCO. For additional information regarding the Jonah expansion project, please read *Capital Spending* included within this Item 2.

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OTHER ITEMS

Non-GAAP reconciliation

The following table presents a reconciliation of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of a change in accounting principle (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Total non-GAAP gross operating margin	$ 310,624	$ 245,875	$ 623,147	$ 521,089
Adjustments to reconcile total non-GAAP gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(107,952)	(101,048)	(212,768)	(201,013)
Operating lease expense paid by EPCO	(528)	(528)	(1,056)	(1,056)
Gain (loss) on sale of assets in operating costs and expenses	136	(83)	197	5,353
General and administrative costs	(16,235)	(18,710)	(29,975)	(33,403)
GAAP consolidated operating income	186,045	125,506	379,545	290,970
Other expense	(52,940)	(55,501)	(109,048)	(107,995)
GAAP income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 133,105	$ 70,005	$ 270,497	$ 182,975

EPCO subleases certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the retained leases) to us. These subleases are part of an administrative services agreement between EPCO and us that was executed in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution of the retained leases to us.

Cumulative effect of change in accounting principle

Net income for the first quarter of 2006 includes a non-cash benefit of $1.5 million related to the cumulative effect of a change in accounting principle resulting from our adoption of SFAS 123(R) on January 1, 2006. For additional information regarding this cumulative effect adjustment, please read Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Provision for income taxes Texas Margin Tax

Prior to the second quarter of 2006, our provision for income taxes related to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represented our only consolidated subsidiaries that were historically subject to such income taxes. In May 2006, the State of Texas enacted a new business tax (the Texas Margin Tax) that replaced the existing state 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 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. The Texas Margin Tax becomes effective for margin 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. The taxable margin is the lesser of (1) 70% of total revenue or (2) total revenue less (a) cost of goods sold or (b) compensation and benefits. Our deferred tax liability, which is a component of other long-term liabilities on our consolidated balance sheets, reflects the net tax effects of temporary differences related to items such as property, plant and equipment. Therefore, the deferred tax liability is noncurrent. We have calculated and recorded an estimated deferred tax liability of approximately $6.1 million for the Texas Margin Tax. The non-cash offsetting charge of $6.1 million is shown on our unaudited condensed statements of consolidated operations and comprehensive income as a component of provision for income taxes for the three months and six months ended June 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 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 or 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.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND RISK FACTORS

This quarterly report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as anticipate, project, expect, plan, goal, forecast, intend, believe, may and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations (as reflected in such forward-looking statements) are reasonable, neither we nor Enterprise Products GP can give any assurance that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

When considering forward-looking statements, please read Part II, Item 1A, *Risk Factors*, included within this quarterly report on Form 10-Q and Part I, Item 1A, *Risk Factors*, included in our annual report on Form 10-K for 2005.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in certain interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair value hedges Interest rate swaps. As summarized in the following table, we had eleven interest rate swap agreements outstanding at June 30, 2006 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.15%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 6.69%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 6.14%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.73%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The total fair value of these eleven interest rate swaps at June 30, 2006 and December 31, 2005, was a liability of $64.9 million and $19.2 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2006 and 2005 reflects a $1.1 million expense and a $2.9 million benefit from these swap agreements, respectively. For the six months ended June 30, 2006 and 2005, interest expense reflects a $0.9 million expense and a $7.5 million benefit, respectively, from these swap agreements.

The following table shows the effect of hypothetical price movements on the estimated fair value (FV) of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic reset rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published on the first day of each six-month interest calculation period.

	Resulting	Swap Fair Value at

Scenario	Classification	June 30, 2006	July 20, 2006
FV assuming no change in underlying interest rates	*Asset (Liability)*	$(64,869)	$(56,350)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(98,063)	(88,615)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	(31,676)	(24,085)

The change in fair value of our interest rate swaps since December 31, 2005 is primarily due to an increase in interest rates.

Cash flow hedges Treasury Locks. During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership s purpose of entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt. In July 2006, the Operating Partnership issued $300 million in principal amount of its Junior Notes A. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with such products, we may enter into commodity financial instruments. The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products.

The fair value of our commodity financial instrument portfolio at June 30, 2006 and December 31, 2005 was a liability of $7.8 million and $0.1 million, respectively. During the three and six months ended June 30, 2006, we recorded $5.7 million and $5.3 million of expense related to our commodity financial instruments, respectively, which is included in operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income. We recorded nominal amounts of earnings from our commodity financial instruments during the three and six months ended June 30, 2005.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. This analysis measures potential income or loss resulting from changes in fair value of the portfolio, based upon a hypothetical 10% change in the underlying quoted market prices of the commodity financial instruments. The following table shows the effect of such hypothetical price movements on the estimated fair value of our commodity financial instrument portfolio at the dates indicated (dollars in thousands):

		Commodity Financial Instrument Portfolio FV	
Scenario	**Resulting Classification**	**June 30, 2006**	**July 20, 2006**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (7,785)	$ (5,791)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(16,536)	(13,653)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	966	2,072

Effect of financial instruments on accumulated other comprehensive income

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income since December 31, 2005.

	Commodity Financial Instruments	**Interest Rate Financial Instruments**	**Accumulated Other Comprehensive Income Balance**
Balance, December 31, 2005		$19,072	$ 19,072
Change in fair value of commodity financial instruments	$(7,700)		(7,700)
Reclassification of gain on settlement of interest rate financial instruments		(2,093)	(2,093)

Reclassification of change in fair value of interest rate financial instruments		1,638	1,638
Balance, June 30, 2006	$(7,700)	$18,617	$ 10,917

During the remainder of 2006, we will reclassify $2.1 million from accumulated other comprehensive income to earnings as a reduction in consolidated interest expense.

Item 4. ***Controls and Procedures*****.**

Our management, with the participation of the chief executive officer (CEO) and chief financial officer (CFO) of our general partner, has evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of the end of the period covered by this report. Based on their evaluation, the CEO and CFO of our general partner have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our partnership is made known to management on a timely basis. Our CEO and CFO noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. Also, they detected no fraud involving management or employees who have a significant role in our internal controls over financial reporting.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have not been evaluated by management and no other factors that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Collectively, these disclosure controls and procedures are designed to provide us with reasonable assurance that the information required to be disclosed in our periodic reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected.

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 quarterly report on Form 10-Q.

PART II. OTHER INFORMATION.

Item 1. ***Legal Proceedings*****.**

See Part I, Item 1, Financial Statements, Note 15, *Commitments and Contingencies Litigation*, which is incorporated herein by reference.

Item 1A. ***Risk Factors*****.**

Apart from that discussed below, there have been no significant changes in our risk factors since December 31, 2005. For a detailed discussion of our risk factors, please read, Item 1A *Risk Factors*, in our annual report on Form 10-K for 2005.

Tax Risks to Common Unitholders

If we were to become subject to entity level taxation for federal or state tax purposes, then our cash available for distribution to common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we likely would pay state taxes as well. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow though to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for United States federal income tax purposes or otherwise subjecting us to entity level taxation. For example, because of widespread state budget deficits, certain states, including Texas, have taken steps to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. To the extent any state imposes an income tax or other tax upon us as an entity, the cash available for distribution to our common unitholders would be reduced.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds*.**

We did not repurchase any of our common units during the three and six months ended June 30, 2006. As of June 30, 2006, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program.

Item 3. ***Defaults Upon Senior Securities*.**

None.

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

None.

Item 5. ***Other Information*.**

None.

Item 6. ***Exhibits*.**

Exhibit Number	Exhibit*
2.1	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 26, 2000).
2.2	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 8, 2002.)
2.3	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 8, 2002).
2.4	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P. dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Form 8-K filed August 12, 2002).
2.5	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 12, 2002).
2.6	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.7	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).

2.8 Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products

Exhibit Number	Exhibit*
	Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.9	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.10	Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003, (incorporated by reference to Exhibit 2.3 to Form 8-K filed December 15, 2003).
2.11	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C. adopted by Enterprise Products GTM, LLC as of September 30, 2004 (incorporated by reference to Exhibit 2.11 to Registration Statement on Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
2.12	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.2	Third Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of August 29, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 1, 2005).
3.3	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003)(incorporated by reference to Exhibit 3.1 to Form 8-K filed July 1, 2005).
3.4	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.5	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
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	$2.25 Billion 364-Day Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citicorp North America, Inc. and Lehman Commercial Paper Inc., as Co-Syndication Agents, JPMorgan Chase Bank, UBS Loan Finance LLC and Morgan Stanley Senior Funding, Inc., as Co-Documentation Agents, Wachovia Capital Markets, LLC, Citigroup Global Markets Inc. and Lehman Brothers Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.3 to Form 8-K filed on August 30, 2004).
4.2	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.3#	Second Amendment dated June 22, 2006, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, CitiBank, N.A. and JPMorgan Chase Bank, as CO-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents.
4.4	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee. (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.5	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2005).

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18.1	Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Form 10-Q filed May 10, 2004).
31.1#	Sarbanes-Oxley Section 302 certification of Robert G. Phillips for Enterprise Products Partners L.P. for the June 30, 2006 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2006 quarterly report on Form 10-Q.
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32.2#	Section 1350 certification of Michael A. Creel for the June 30, 2006 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

\# Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on August 8, 2006.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By:	Enterprise Products GP, LLC, as General Partner
By:	/s/ Michael J. Knesek
Name:	Michael J. Knesek
Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

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