ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
August 08, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2007

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

1100 Louisiana, 10th Floor

Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)

(713) 381-6500
(Registrant s Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

There were 434,062,817 common units of Enterprise Products Partners L.P. outstanding at August 1, 2007. These common units trade on the New York Stock Exchange under the ticker symbol EPD.

ENTERPRISE PRODUCTS PARTNERS L.P.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION.

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

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

ASSETS	**June 30, 2007**	**December 31, 2006**
Current assets:		
Cash and cash equivalents	$ 63,363	$ 22,619
Restricted cash	23,359	23,667
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $22,868 at June 30, 2007 and $23,406 at December 31, 2006	1,491,856	1,306,290
Accounts receivable - related parties	91,619	16,738
Inventories	335,622	423,844
Prepaid and other current assets	173,327	129,000
Total current assets	2,179,146	1,922,158
Property, plant and equipment, net	10,734,130	9,832,547
Investments in and advances to unconsolidated affiliates	836,091	564,559
Intangible assets, net of accumulated amortization of $297,002 at June 30, 2007 and $251,876 at December 31, 2006	950,260	1,003,955
Goodwill	590,647	590,541
Deferred tax asset	2,369	1,855
Other assets	77,630	74,103
Total assets	$ 15,370,273	$ 13,989,718
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 285,671	$ 277,070
Accounts payable related parties	32,846	6,785
Accrued gas payables	1,552,074	1,364,493
Accrued expenses	44,539	35,763
Accrued interest	94,837	90,865
Other current liabilities	194,894	209,945
Total current liabilities	2,204,861	1,984,921
Long-term debt: (see Note 9)		
Senior debt obligations principal	5,063,949	4,779,068
Junior Subordinated Notes A principal	550,000	550,000
Junior Subordinated Notes B principal	700,000	--
Other	(54,234)	(33,478)
Total long-term debt	6,259,715	5,295,590
Deferred tax liabilities	17,310	13,723
Other long-term liabilities	108,716	86,121
Minority interest	434,665	129,130
Commitments and contingencies		
Partners equity:		
Limited partners		
Common units (432,466,493 units outstanding at June 30, 2007 and 431,303,193 units outstanding at December 31, 2006)	6,145,945	6,320,577
Restricted common units (1,596,324 units outstanding at June 30, 2007		

and 1,105,237 units outstanding at December 31, 2006)	11,389	9,340
General partner	126,037	129,175
Accumulated other comprehensive income	61,635	21,141
Total partners equity	6,345,006	6,480,233
Total liabilities and partners equity	$ 15,370,273	$ 13,989,718

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS

(Dollars in thousands, except per unit amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Revenues:				
Third parties	$ 4,076,573	$ 3,404,419	$ 7,335,185	$ 6,564,418
Related parties	136,233	113,434	200,475	203,509
Total	4,212,806	3,517,853	7,535,660	6,767,927
Costs and expenses:				
Operating costs and expenses:				
Third parties	3,875,050	3,244,576	6,915,583	6,189,796
Related parties	85,622	79,009	169,568	180,652
Total operating costs and expenses	3,960,672	3,323,585	7,085,151	6,370,448
General and administrative costs:				
Third parties	10,628	5,405	14,203	8,137
Related parties	20,733	10,830	33,788	21,838
Total general and administrative costs	31,361	16,235	47,991	29,975
Total costs and expenses	3,992,033	3,339,820	7,133,142	6,400,423
Equity in income (loss) of unconsolidated affiliates	(6,211)	8,012	(32)	12,041
Operating income	214,562	186,045	402,486	379,545
Other income (expense):				
Interest expense	(71,275)	(56,333)	(134,633)	(114,410)
Interest income	2,408	1,455	4,443	3,116
Other, net	339	1,938	232	2,246
Other expense	(68,528)	(52,940)	(129,958)	(109,048)
Income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle	146,034	133,105	272,528	270,497
Provision for income taxes	1,860	(6,272)	(6,928)	(9,164)
Income before minority interest and the cumulative effect of change in accounting principle	147,894	126,833	265,600	261,333
Minority interest	(5,740)	(538)	(11,401)	(2,736)
Income before the cumulative effect of change in accounting principle	142,154	126,295	254,199	258,597
Cumulative effect of change in accounting principle (see Note 2)	--	--	--	1,475
Net income	$ 142,154	$ 126,295	$ 254,199	$ 260,072
Net income allocation: (see Note 13)				
Limited partners interest in net income	$ 113,527	$ 103,192	$ 198,576	$ 215,561
General partner interest in net income	$ 28,627	$ 23,103	$ 55,623	$ 44,511
Earning per unit: (see Note 13)				
Basic income per unit before change in accounting principle	$ 0.26	$ 0.25	$ 0.46	$ 0.53
Basic income per unit	$ 0.26	$ 0.25	$ 0.46	$ 0.54
Diluted income per unit before change in accounting principle	$ 0.26	$ 0.25	$ 0.46	$ 0.53
Diluted income per unit	$ 0.26	$ 0.25	$ 0.46	$ 0.54

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED

COMPREHENSIVE INCOME

(Dollars in thousands)

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Net income	$ 142,154	$ 126,295	$ 254,199	$ 260,072
Other comprehensive income:				
Cash flow hedges:				
Net commodity financial instrument gains (losses) during period	(3,121)	(7,951)	846	(7,700)
Net interest rate financial instrument gains during period	29,752	1,638	40,264	1,638
Less: Amortization of cash flow financing hedges	(1,180)	(1,052)	(2,269)	(2,093)
Total cash flow hedges	25,451	(7,365)	38,841	(8,155)
Foreign currency translation adjustment	148	--	549	--
Total other comprehensive income	25,599	(7,365)	39,390	(8,155)
Comprehensive income	$ 167,753	$ 118,930	$ 293,589	$ 251,917

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in thousands)

	For the Six Months Ended June 30,	
	2007	2006
Operating activities:		
Net income	$ 254,199	$ 260,072
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	240,653	212,768
Depreciation and amortization in general and administrative costs	4,259	3,752
Amortization in interest expense	201	487
Equity in loss (income) of unconsolidated affiliates	32	(12,041)
Distributions received from unconsolidated affiliates	35,026	20,348
Cumulative effect of change in accounting principle	--	(1,475)
Operating lease expense paid by EPCO, Inc.	1,053	1,056
Minority interest	11,401	2,736
Loss (gain) on sale of assets	5,664	(197)
Deferred income tax expense	4,088	9,180
Changes in fair market value of financial instruments	(302)	(53)
Net effect of changes in operating accounts (see Note 16)	(4,225)	74,692
Net cash flows provided by operating activities	552,049	571,325
Investing activities:		
Capital expenditures	(1,129,263)	(613,519)
Contributions in aid of construction costs	48,570	34,941
Proceeds from sale of assets	1,015	256
Decrease (increase) in restricted cash	308	(6,703)
Cash used for business combinations	(785)	--
Investments in unconsolidated affiliates	(294,598)	(111,882)
Advances (to) from unconsolidated affiliates	(12,434)	7,120
Net cash used in investing activities	(1,387,187)	(689,787)
Financing activities:		
Borrowings under debt agreements	3,048,734	1,435,000
Repayments of debt	(2,063,374)	(1,402,000)
Debt issuance costs	(9,261)	--
Distributions paid to partners	(470,561)	(400,474)
Distributions paid to minority interests	(9,416)	(4,131)
Net proceeds from initial public offering of Duncan Energy Partners reflected as a contribution from minority interests (see Notes 1 and 2)	291,044	--
Other contributions from minority interests	12,506	19,018
Settlement of treasury lock contracts	42,269	--
Repurchase of restricted units and options	(1,568)	--
Net proceeds from issuance of our common units	35,899	453,475
Net cash provided by financing activities	876,272	100,888
Effect of exchange rate changes on cash	(390)	--
Net change in cash and cash equivalents	41,134	(17,574)
Cash and cash equivalents, January 1	22,619	42,098
Cash and cash equivalents, June 30	$ 63,363	$ 24,524

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS EQUITY

(See Note 10 for Unit History and Detail of Changes in Limited Partners Equity)

(Dollars in thousands)

	Limited Partners	General Partner	AOCI	Total
Balance, December 31, 2006	$ 6,329,917	$ 129,175	$ 21,141	$ 6,480,233
Net income	198,576	55,623	--	254,199
Operating leases paid by EPCO, Inc.	1,032	21	--	1,053
Cash distributions to partners	(407,826)	(59,896)	--	(467,722)
Net proceeds from sales of common units	27,676	877	--	28,553
Proceeds from exercise of unit options	7,139	207	--	7,346
Repurchase of restricted units and options	(1,568)	--	--	(1,568)
Unit option reimbursements to EPCO, Inc.	(2,786)	(57)	--	(2,843)
Change in funded status of pension and postretirement plans, net of tax	--	--	1,104	1,104
Amortization of equity awards	5,174	87	--	5,261
Foreign currency translation adjustment	--	--	549	549
Cash flow hedges	--	--	38,841	38,841
Balance, June 30, 2007	$ 6,157,334	$ 126,037	$ 61,635	$ 6,345,006

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Partnership Organization

Partnership Organization

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 Prod Partners are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated 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 LLC (EPO), as successor in interest by merger to Enterprise Products Operating L.P. 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 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 affiliate, the units of which are listed on the NYSE under the ticker symbol TPP. References to TEPPCO GP refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to Energy Transfer Equity mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to ETE GP mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both ETE GP and Energy Transfer Equity.

References to Employee Partnerships mean EPE Unit L.P. (EPE Unit I), EPE Unit II, L.P. (EPE Unit II) and EPE Unit III, L.P. (EPE Unit III), collectively, which are private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. (Duncan Energy Partners), completed an initial public offering of its common units (see Note 12). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners net assets and earnings are presented as a component of minority interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

Our results of operations for the three and six months ended June 30, 2007 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, the 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 EPO s level in our consolidated financial statements. We act as guarantor of certain of EPO s debt obligations. See Note 17 for condensed consolidated financial information of EPO.

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 the 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). These Unaudited Condensed Consolidated Financial Statements should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2006 (Commission File No. 1-14323).

Note 2. General Accounting Policies and Related Matters

Accounting for Employee Benefit Plans

Dixie Pipeline Company (Dixie), a consolidated subsidiary, employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a 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 each of the three month periods ended June 30, 2007 and 2006. During each of the six month periods ended June 30, 2007 and 2006, Dixie contributed $0.2 million to its company-sponsored defined contribution plan.

Pension and Postretirement Benefit Plans. Dixie s net pension benefit costs were $0.1 million and $0.2 million for the three months ended June 30, 2007 and 2006, respectively. For each of the six month periods ended June 30, 2007 and 2006, Dixie s net pension benefit costs were $0.3 million. Dixie s net postretirement benefit costs were $0.1 million for each of the three month periods ended June 30, 2007 and 2006. For the six months ended June 30, 2007 and 2006, Dixie s net postretirement benefit costs were $0.2 million and $0.1 million, respectively. During the remainder of 2007, Dixie expects to contribute approximately $1.2 million to its postretirement benefit plan and approximately $0.2 million to its pension plan.

Consolidation Policy

We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership.

If the investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the investee s operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee s operating and financial policies. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts remain on our balance sheet (or those of our equity method investees) in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Cumulative Effect of Change in Accounting Principle

In January 2006, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) 123(R), Share-Based Payment. Upon adoption of this accounting standard, we recognized, as a benefit, a cumulative effect of change in accounting principle of $1.5 million.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies, and regulatory approvals. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At June 30, 2007 and December 31, 2006, our accrued liabilities for environmental remediation projects totaled $28.6 million and $24.2 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

In February 2007, we reserved $6.5 million in cash received from a third party to fund anticipated future environmental remediation costs associated with certain assets that we had acquired from the third party. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification was terminated.

Estimates

Preparing our Unaudited Condensed Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect 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 the reporting period. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Income Taxes

We are organized as a pass-through entity for income tax purposes. As a result, our partners are responsible for federal income taxes on their share of our taxable income. For the three and six months ended June 30, 2007 and 2006, our provision for income taxes is applicable to state tax obligations under the Texas Margin Tax and certain federal and state tax obligations of Seminole Pipeline Company (Seminole) and Dixie.

In accordance with Financial Accounting Standards Board Interpretation (FIN) 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows.

Minority Interest

As presented in our Unaudited Condensed Consolidated Balance Sheets, minority interest represents third-party ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third-party ownership interests in such amounts presented as minority interest. Effective February 1, 2007, the public owners of Duncan Energy Partners common units are presented as a minority interest in our consolidated financial statements.

Minority interest, as reflected on our June 30, 2007 balance sheet, consists of $293.5 million attributable to third party owners of Duncan Energy Partners and the remainder to our other consolidated affiliates.

Minority interest expense for the three and six months ended June 30, 2007 includes $3.3 million and $6.1 million, respectively, attributable to third party owners of Duncan Energy Partners. The remaining minority interest expense amounts for these periods in 2007 and likewise those for 2006 are attributable to our other consolidated affiliates.

Contributions from minority interests for the six months ended June 30, 2007 includes $291.0 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Recent Accounting Developments

SFAS 157, Fair Value Measurements, defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and we will be required to adopt SFAS 157 on January 1, 2008. We do not believe SFAS 157 will have a material impact on our financial position, results of operations, and cash flows since we already apply its basic concepts in measuring fair values used to record various transactions such as business combinations and asset acquisitions.

SFAS 159, Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115, permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We do not believe SFAS 159 will have a material impact on our financial position, results of operations, and cash flows.

Note 3. Accounting for Unit-Based Awards

We account for unit-based awards in accordance with SFAS 123(R). SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity-classified award is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period.

Unit Options and Restricted Units

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.

The information in the following table presents unit option activity under the 1998 Plan for the periods indicated:

	Number of Units	**Weighted-average strike price (dollars/unit)**	**Weighted-average remaining contractual term (in years)**	**Aggregate Intrinsic Value** [1]
Outstanding at December 31, 2006	2,416,000	$ 23.32		
Granted [2]	795,000	30.96		
Exercised	(230,500)	18.89		
Settled	(710,000)	24.35		
Outstanding at June 30, 2007	2,270,500	26.12	8.14	$ 3,502
Options exercisable at:				
June 30, 2007	360,500	$ 22.10	4.52	$ 3,502

(1) Aggregate intrinsic value reflects fully vested unit options at June 30, 2007.

(2) The total grant date value of these awards was $2.1 million based on the following assumptions (i) expected life of the option of seven years; (ii) risk-free interest rate of 4.83%; (iii) expected distribution yield on units of 8.42%; and (iv) expected unit price volatility on units of 23.21%.

The total intrinsic value of unit options exercised during the three and six months ended June 30, 2007 was $1.2 million and $2.8 million, respectively. We recognized $3.9 million and $0.2 million of compensation expense associated with unit options during the three month periods ended June 30, 2007 and 2006, respectively. We recognized $4.1 million and $0.3 million of compensation expense associated with unit options during the six months ended June 30, 2007 and 2006, respectively. Compensation expense for the three and six months ended June 30 ,2007 includes $3.7 million associated with the resignation of our former chief executive officer.

As of June 30, 2007, there was an estimated $3.2 million of total unrecognized compensation cost related to non-vested unit options granted under the 1998 Plan. We expect to recognize our share of this cost over a weighted-average period of 3.25 years in accordance with the EPCO administrative services agreement.

During the six months ended June 30, 2007 and 2006, we received cash of $7.3 million and $1.6 million, respectively, from the exercise of unit options, and our option-related reimbursements to EPCO were $2.8 million and $0.7 million, respectively.

Under the 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. The following table summarizes information regarding our restricted common units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit [(1)]
Restricted units at December 31, 2006	1,105,237	
Granted [(2)]	620,140	$ 25.74
Forfeited or settled	(129,053)	$ 23.28
Restricted units at June 30, 2007	1,596,324	

(1) Determined by dividing the aggregate grant date fair value of awards (including an allowance for forfeitures) by the number of awards issued.

(2) Aggregate grant date fair value of restricted common unit awards issued during 2007 was $16.0 million based on a grant date market price of our common units ranging from $30.16 to $30.96 per unit and estimated forfeiture rates ranging from 9.2% to 17.0%.

During the three months ended June 30, 2007 and 2006, we recognized $2.3 million and $1.8 million, respectively, of compensation expense in connection with restricted common units. We recognized $3.7 million and $2.7 million of compensation expense in connection with restricted common units during the six months ended June 30, 2007 and 2006, respectively. No restricted units vested during the three and six months ended June 30, 2007. Compensation expense for the three and six months ended June 30 ,2007 includes $0.9 million associated with the resignation of our former chief executive officer.

As of June 30, 2007, there was $27.8 million of total unrecognized compensation cost related to restricted common units. We will recognize our share of such costs in accordance with the EPCO administrative services agreement. At June 30, 2007, these costs are expected to be recognized over a weighted-average period of 2.8 years.

The 1998 Plan provides for the issuance of up to 7,000,000 common units. As of June 30, 2007, 1,689,500 common units had been issued in connection with the exercise of unit options. After giving effect to outstanding unit options at June 30, 2007 and the issuance and forfeiture of restricted common units through June 30, 2007, a total of 3,606,303 additional common units could be issued under the 1998 Plan.

Employee Partnerships

For the three months ended June 30, 2007 and 2006, we recorded $0.7 million and $0.6 million, respectively, of compensation expense associated with EPE Unit I, EPE Unit II and EPE Unit III (the Employee Partnerships). We recorded $1.2 million and $1.1 million of compensation expense associated with the Employee Partnerships during the six months ended June 30, 2007 and 2006, respectively. As of June 30, 2007, there was $8.2 million of total unrecognized compensation cost related to EPE Unit I and EPE Unit II, of which we will recognize our share in accordance with the EPCO administrative services agreement.

EPE Unit III. EPE Unit III was formed on May 7, 2007 and owns 4,421,326 units of Enterprise GP Holdings contributed to it by a private company affiliate of EPCO, which, in turn, was made the Class A limited partner of EPE Unit III. On the date of contribution, the fair market value of the units contributed by the Class A limited partner was $170.0 million (the Class A limited partner capital base). Certain EPCO employees were issued Class B limited partner interests and admitted as Class B limited partners of EPE Unit III without any capital contribution. The profits interest awards (i.e., Class B limited partner interests) in EPE Unit III entitle the holder to participate in the appreciation in value of units of Enterprise GP Holdings owned by EPE Unit III.

Unless otherwise agreed to by EPCO, the Class A limited partner and a majority in interest of the Class B limited partners of EPE Unit III, EPE Unit III will be liquidated upon the earlier of: (i) May 7, 2012 or (ii) a change in control of Enterprise GP Holdings or its general partner. EPE Unit III has the following material terms regarding its quarterly cash distribution to partners:

§ Distributions of Cashflow Each quarter, 100% of the cash distributions received by EPE Unit III from Enterprise GP Holdings will be distributed to the Class A limited partner until it has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by EPE Unit III will be distributed to the Class B limited partners. The Class A preferred return equals 3.797%, of the Class A limited partner s capital base. The Class A limited partner s capital base equals approximately $170.0 million plus any unpaid Class A preferred return from prior periods, less any distributions made by EPE Unit III of proceeds from the sale of Enterprise GP Holdings units owned by EPE Unit III (as described below).

§ Liquidating Distributions Upon liquidation of EPE Unit III, units having a fair market value equal to the Class A limited partner capital base will be distributed to a private company affiliate of EPCO, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

§ Sale Proceeds If EPE Unit III sells any of the 4,421,326 of Enterprise GP Holdings units that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in EPE Unit III that are owned by EPCO employees are subject to forfeiture if the participating employee s employment with EPCO and its affiliates is terminated prior to May 7, 2012, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in EPE Unit III will also lapse upon certain change of control events.

As of June 30, 2007, there was $22.4 million of total unrecognized compensation cost related to these awards, of which we will recognize our share in accordance with the EPCO administrative services agreement.

Note 4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. 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) variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. 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 exposure 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, 2007 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 8.74%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.28%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.30%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.80%	$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, 2007 and December 31, 2006, was a liability of $49.7 million and $29.1 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2007 and 2006 includes a $2.3 million and $1.1 million loss from these swap agreements, respectively. For the six months ended June 30, 2007 and 2006, interest expense reflects a loss of $4.6 million and $0.9 million from these swap agreements, respectively.

Cash Flow Hedges Treasury Locks. During the fourth quarter of 2006, EPO entered into treasury lock transactions having a notional value of $562.5 million. EPO entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during the second and fourth quarters of 2007. On February 27, 2007, EPO entered into additional treasury lock transactions having a notional value of $437.5 million. EPO entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during 2007. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted.

During the second quarter of 2007, treasury locks having a notional amount of $875.0 million were terminated. Treasury locks having a notional amount of $500.0 million were terminated concurrent with the issuance of EPO s Junior Notes B (see Note 9). An additional $375.0 million notional amount of treasury locks related to the anticipated issuance of debt in the fourth quarter of 2007 were also terminated. The termination of the treasury locks resulted in gains of $42.3 million of which $10.6 million is related to EPO s Junior Notes B and the remaining $31.7 million is related to a future debt issuance. The $10.6 million gain is being amortized into income using the effective interest method as reductions to future interest expense over the fixed rate term of the Junior Notes B, which is ten years. The remaining $31.7 million gain will be amortized into income over the life of the future debt issuance using the effective interest rate method.

At June 30, 2007, there was one treasury lock outstanding which has a notional amount of $125.0 million and a fair value of $9.3 million.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain 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 price 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) the value of 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. From time to time, we inject natural gas into storage and utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

14

At June 30, 2007 and December 31, 2006, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of cash flow hedges. The fair value of our commodity financial instrument portfolio at June 30, 2007 and December 31, 2006 was a liability of $1.0 million and $3.2 million, respectively. During the three and six months ended June 30, 2007, we recorded income of $1.1 million and expense of $1.3 million, respectively, related to our commodity financial instruments. During the three and six months ended June 30, 2006 we recorded $5.9 million and $5.5 million, respectively, of expense related to our commodity financial instruments.

Foreign Currency Hedging Program

We own an NGL marketing business located in Canada and have entered into construction agreements where payments are indexed to the Canadian dollar. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Due to the limited duration of these contracts, we utilize mark-to-market accounting for these transactions, the effect of which has had a minimal impact on our earnings. We had $3.1 million of such contracts outstanding at June 30, 2007 that settled in July 2007.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	June 30, 2007	**December 31, 2006**
Working inventory	$ 325,539	$ 387,973
Forward-sales inventory	10,083	35,871
Inventory	$ 335,622	$ 423,844

Our regular trade (or working) inventory is comprised of inventories of natural gas, NGLs, and certain 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. Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Unaudited Condensed Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our cost of sales was $3.6 billion and $3.0 billion for the three months ended June 30, 2007 and 2006, respectively. For the six months ended June 30, 2007 and 2006, our cost of sales was $6.4 billion and $5.7 billion, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market (LCM) adjustments when the carrying value 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, 2007 and 2006, we recognized LCM adjustments of approximately $2.1 million and $0.3 million, respectively. We recognized LCM adjustments of $13.1 million and $12.0 million for the six months ended June 30, 2007 and 2006, respectively.

15

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	June 30, 2007	December 31, 2006
Plants and pipelines (1)	3-35 (5)	$ 9,454,757	$ 8,774,683
Underground and other storage facilities (2)	5-35 (6)	679,147	596,649
Platforms and facilities (3)	20-31	591,272	161,839
Transportation equipment (4)	3-10	28,964	27,008
Land		41,945	40,010
Construction in progress		1,632,248	1,734,083
Total		12,428,333	11,334,272
Less accumulated depreciation		1,694,203	1,501,725
Property, plant and equipment, net		$ 10,734,130	$ 9,832,547

(1) Plants and pipelines include 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 include underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities include 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 as follows: 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 as follows: 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, 2007 and 2006 was $99.1 million and $86.9 million, respectively. For the six months ended June 30, 2007 and 2006, depreciation expense was $194.1 million and $170.4 million, respectively. We capitalized $20.4 million and $12.4 million of interest in connection with capital projects during the three months ended June 30, 2007 and 2006, respectively. During the six months ended June 30, 2007 and 2006, we capitalized $41.1 million and $21.6 million, respectively, in connection with capital projects.

Note 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 of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 11 for a general discussion of our business segments.

The following table presents our investments in and advances to unconsolidated affiliates at the dates indicated:

	Ownership Percentage at June 30, 2007	Investments in and advances to unconsolidated affiliates at June 30, 2007	December 31, 2006
NGL Pipelines & Services:			
Venice Energy Service Company L.L.C. (VESCO)	13.1%	$ 42,340	$ 39,618
K/D/S Promix, L.L.C. (Promix)	50%	55,091	46,140
Baton Rouge Fractionators LLC (BRF)	32.3%	25,057	25,471
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company (Jonah)	19.6%	200,649	120,370
Evangeline [1]	49.5%	3,641	4,221
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (Poseidon)	36%	59,161	62,324
Cameron Highway Oil Pipeline Company (Cameron Highway [2])	50%	259,369	60,216
Deepwater Gateway, L.L.C. (Deepwater Gateway)	50%	113,345	117,646
Neptune Pipeline Company, L.L.C. (Neptune)	25.7%	56,676	58,789
Nemo Gathering Company, LLC (Nemo [3])	33.9%	2,637	11,161
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	13,896	13,912
La Porte [4]	50%	4,229	4,691
Total		$ 836,091	$ 564,559

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

(2) During the second quarter of 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway s debt. See Cameron Highway discussion within this Note 7.

(3) During the three months ended June 30, 2007, we recorded a $7.0 million non-cash impairment charge attributable to our investment in Nemo. See Nemo discussion within this Note 7.

(4) 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 acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At June 30, 2007 and December 31, 2006, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway, Nemo and Jonah included excess cost amounts totaling $42.9 million and $38.7 million, respectively. These amounts are attributable to the excess of the fair value of each entity s tangible assets over their respective book carrying values at the time we acquired an interest in each entity. We amortize such excess cost amounts as a reduction in equity earnings. Amortization of such excess cost amounts was $0.5 million and $0.6 million during the three months ended June 30, 2007 and 2006, respectively. For the six months ended June 30, 2007 and 2006, amortization of such amounts was $1.0 million and $1.1 million, respectively.

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended June 30, 2007	2006	For the Six Months Ended June 30, 2007	2006
NGL Pipelines & Services	$ 1,089	$ 1,924	$ 1,680	$ 3,442
Onshore Natural Gas Pipelines & Services	1,212	904	2,241	1,506
Offshore Pipelines & Services [1] [2]	(8,846)	4,769	(4,771)	6,703
Petrochemical Services	334	415	818	390
Total	$ (6,211)	$ 8,012	$ (32)	$ 12,041

(1) Equity earnings from Nemo for the three and six months ended June 30, 2007 includes a $7.0 million non-cash impairment charge. See Nemo discussion within this Note 7.

(2) Equity earnings from Cameron Highway for the three and six months ended June 30, 2007 were reduced by a charge of $8.8 million for costs associated with the early retirement of Cameron Highway s debt.

Summarized Financial Information of Unconsolidated Affiliates

The following tables present 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, 2007			**June 30, 2006**		
	Revenues	**Operating Income (Loss)**	**Net Income (Loss)**	**Revenues**	**Operating Income (Loss)**	**Net Income (Loss)**
NGL Pipelines & Services [1]	$ 59,056	$ (779)	$ (74)	$ 60,220	$ (2,238)	$ (1,785)
Onshore Natural Gas Pipelines & Services	125,132	25,198	24,102	117,636	20,127	16,315
Offshore Pipelines & Services	40,433	24,146	1,894	39,554	20,166	12,804
Petrochemical Services	4,969	1,403	1,429	5,557	1,645	1,665

(1) During the three months ended June 30, 2006, VESCO earnings were reduced due to the lingering effects of Hurricane Katrina, including significant storm-related repair expenses.

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2007			**June 30, 2006**		
	Revenues	**Operating Income**	**Net Income**	**Revenues**	**Operating Income (Loss)**	**Net Income (Loss)**
NGL Pipelines & Services [1]	$ 100,788	$ 2,481	$ 3,755	$ 80,506	$ (24,363)	$ (23,463)
Onshore Natural Gas Pipelines & Services	234,030	46,813	44,415	226,424	59,023	50,759
Offshore Pipelines & Services	77,626	43,864	14,230	71,250	31,096	16,484
Petrochemical Services	10,522	3,290	3,340	9,425	1,831	1,875

(1) During the six months ended June 30, 2006, VESCO earnings were reduced due to the lingering effects of Hurricane Katrina, including significant storm-related repair expenses.

Cameron Highway

We own a 50.0% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. In May 2007, we made an approximate $191.0 million cash contribution to Cameron Highway. This capital contribution, along with an equal amount contributed by our joint venture partner in Cameron Highway, was used by Cameron Highway to repay $365.0 million outstanding under its Senior Notes A and $14.1 million of related make-whole premiums and accrued interest. In June 2007, we and our joint venture partner in Cameron Highway, made an additional capital contribution of approximately $25.5 million each. These capital contributions were used by Cameron Highway to repay its Series B notes on June 7, 2007. The amount of the repayment was $50.9 million, which included $0.9 million of related make-whole premiums and accrued interest. As of June 30, 2007, Cameron Highway no longer has any outstanding debt.

Nemo

Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

At December 31, 2006, the carrying value of our investment in Nemo was $11.2 million, which included $0.6 million of excess cost related to its original acquisition in 2001. Our review of Nemo s estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash charge of $7.0 million. This loss is recorded as a component of Equity in income of unconsolidated affiliates in our Unaudited Condensed Statements of Consolidated Operations for the three and six months ended June 30, 2007. Equity earnings from our investment in Nemo are classified under our Offshore Pipelines & Services business segment.

After recording this impairment charge, the carrying value of our investment in Nemo at June 30, 2007 was $2.6 million, which reflects $0.5 million in losses and $2.0 million of distributions we recorded during the first six months of 2007.

Our investment in Nemo was written down to fair value, which management prepared using recognized business valuation techniques. The fair value analysis is based upon management s expectation of future cash flows. Such expectation of future cash flows incorporates industry information and assumptions made by management. For example, the review of Nemo included management estimates regarding the remaining natural gas reserves of producers served by the Nemo Gathering System. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	June 30, 2007			**December 31, 2006**		
	Gross Value	**Accum. Amort.**	**Carrying Value**	**Gross Value**	**Accum. Amort.**	**Carrying Value**
NGL Pipelines & Services (1)	$ 520,025	$ (128,577)	$ 391,448	$ 528,594	$ (110,644)	$ 417,950
Onshore Natural Gas Pipelines & Services	463,551	(93,611)	369,940	463,551	(77,402)	386,149
Offshore Pipelines & Services	207,012	(64,624)	142,388	207,012	(54,636)	152,376
Petrochemical Services	56,674	(10,190)	46,484	56,674	(9,194)	47,480
Total	$ 1,247,262	$ (297,002)	$ 950,260	$ 1,255,831	$ (251,876)	$ 1,003,955

(1) During the second quarter of 2007, we adjusted our preliminary purchase price allocation related to the Piceance Creek Acquisition. This adjustment resulted in the reclassification of $8.5 million from intangible assets to property, plant and equipment.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services	$ 8,801	$ 6,304	$ 18,042	$ 12,665
Onshore Natural Gas Pipelines & Services	8,049	8,348	16,209	16,806
Offshore Pipelines & Services	4,908	5,633	9,988	11,467
Petrochemical Services	498	497	996	996
Total	$ 22,256	$ 20,782	$ 45,235	$ 41,934

For the remainder of 2007, amortization expense associated with our intangible assets is currently estimated at $44.5 million.

Goodwill

The following table summarizes our goodwill amounts by segment at the dates indicated:

	June 30, 2007	December 31, 2006
NGL Pipelines & Services	$ 152,701	$ 152,595
Onshore Natural Gas Pipelines & Services	282,121	282,121
Offshore Pipelines & Services	82,135	82,135
Petrochemical Services	73,690	73,690
Totals	$ 590,647	$ 590,541

Note 9. Debt Obligations

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

	June 30, 2007	December 31, 2006
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011	$ 495,000	$ 410,000
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 (1)	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
Duncan Energy Partners debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	190,000	--
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Canadian Enterprise Revolving Credit Facility, variable rate, due October 2011	9,881	--
Other, 8.75% fixed-rate, due June 2010(2)	5,068	5,068
Total principal amount of senior debt obligations	5,063,949	4,779,068
EPO Junior Subordinated Notes A, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, due January 2068	700,000	--
Total principal amount of senior and junior debt obligations	6,313,949	5,329,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(54,234)	(33,478)
Long-term debt	$ 6,259,715	$ 5,295,590
Standby letters of credit outstanding	$ 4,000	$ 49,858

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at June 30, 2007 and December 31, 2006. With respect to Senior Notes E due in October 2007, EPO has the ability to use cash and available credit capacity under its $1.25 billion Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(2) Represents remaining debt obligations assumed in connection with the GulfTerra Merger.

(3) The June 30, 2007 amount includes $49.7 million related to fair value hedges and a net $4.5 million in unamortized discounts and premiums. The December 31, 2006 amount includes $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts and premiums.

Parent-Subsidiary guarantor relationships

We act as guarantor of the debt obligations of EPO with the exception of the Dixie revolving credit facility and the senior subordinated notes we assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. We do not act as guarantor of the debt obligations of Duncan Energy Partners.

EPO s debt obligations

Apart from that discussed below, there have been no significant changes in the terms of EPO s debt obligations since those reported in our annual report on Form 10-K for the year ended December 31, 2006.

Junior Notes B. EPO sold $700 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 (Junior Notes B) during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO s payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the

Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with the Junior Subordinated Notes A, due August 2066 (Junior Notes A), which were issued during the third quarter of 2006.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, commencing in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month London Interbank Offered Rate (LIBOR) for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that we nor EPO would not redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Duncan Energy Partners debt obligation

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund the $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At June 30, 2007, the balance outstanding under this facility was $190.0 million.

This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy Partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National

Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The revolving credit facility requires Duncan Energy Partners to maintain a leverage ratio for the prior four fiscal quarters of not more than 4.75 to 1.00 at the last day of each fiscal quarter commencing June 30, 2007; provided that, upon the closing of a permitted acquisition, such ratio shall not exceed (a) 5.25 to 1.00 at the last day of the fiscal quarter in which such specified acquisition occurred and at the last day of each of the two fiscal quarters following the fiscal quarter in which such specified acquisition occurred, and (b) 4.75 to 1.00 at the last day of each fiscal quarter thereafter. In addition, prior to obtaining an investment-grade rating by Standard & Poor s Ratings Services, Moody s Investors Service or Fitch Ratings, Duncan Energy Partners interest coverage ratio, for the prior four fiscal quarters shall not be less than 2.75 to 1.00 at the last day of each fiscal quarter commencing June 30, 2007.

The Duncan Energy Partners credit facility contains other customary covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Canadian Debt Obligations

In May 2007, Canadian Enterprise Gas Products, Ltd. (Canadian Enterprise), a wholly-owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate (CPR) loans or Bankers Acceptances and U.S denominated borrowings may be comprised of Alternative Base Rate (ABR) or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers Acceptances carry interest at the rate for Canadian bankers acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at June 30, 2007 and December 31, 2006.

Information regarding variable interest rates paid

The following table presents 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, 2007.

	Range of interest rates paid	Weighted-average interest rate paid
EPO s Multi-Year Revolving Credit Facility	5.82% to 8.25%	5.86%
Duncan Energy Partners Revolving Credit Facility	6.17%	6.17%
Dixie Revolving Credit Facility	5.66% to 5.67%	5.66%
Canadian Enterprise Revolving Credit Facility	4.95% to 5.82%	5.77%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2007	$ --
2008	--
2009	500,000
2010	569,068
2011	1,644,881
Thereafter	3,600,000
Total scheduled principal payments	$ 6,313,949

In accordance with SFAS 6, long-term and current maturities of debt reflect the classification of such obligations at June 30, 2007 and December 31, 2006. With respect to the $500.0 million in principal due under Senior Notes E in October 2007, EPO has the ability to use cash and available credit capacity under its Multi-Year Revolving Credit Facility to fund the repayment of this debt. The preceding table and our Unaudited Condensed Consolidated Balance Sheets at June 30, 2007 and December 31, 2006 reflect this ability to refinance.

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at June 30, 2007, (ii) total debt of each unconsolidated affiliate at June 30, 2007 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	**Total**	**Scheduled Maturities of Debt 2007**	**2008**	**2009**	**2010**	**2011**	**After 2011**
Poseidon	36.0%	$ 91,000	$ --	$ --	$ --	$ --	$ 91,000	$ --
Evangeline	49.5%	25,650	5,000	5,000	5,000	10,650	--	--
Total		$ 116,650	$ 5,000	$ 5,000	$ 5,000	$ 10,650	$ 91,000	$ --

Previously, Cameron Highway s debt consisted of $365.0 million of Series A notes and $50.0 million of Series B notes. Cameron Highway repaid its Series A notes on May 23, 2007 using proceeds from capital contributions from its partners. The total amount of the repayment was $379.1 million, which included an $11.0 million make-whole premium and $3.1 million of accrued interest. Our share of the capital contribution was funded by borrowings under EPO s Multi-Year Revolving Credit Facility. With another capital contribution from its partners, Cameron Highway also repaid its Series B notes on June 7, 2007. The amount of the repayment was $50.9 million, which included a $0.3 million make-whole premium and $0.6 million of accrued interest. As of June 30, 2007, Cameron Highway no longer has any outstanding debt.

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at June 30, 2007. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

Apart from the repayment of Cameron Highway s Series A and Series B notes, there have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in our annual report on Form 10-K for the year ended December 31, 2006.

Note 10. Partners Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or 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.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and 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 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).

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 past issuance of securities under this registration statement, we have the ability to issue approximately $1.4 billion of additional securities under this registration statement as of June 30, 2007.

In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 932,800 of our common units were issued in February 2007 and May 2007 in connection with the DRIP and the employee unit purchase plan (EUPP). The issuance of these units generated $28.6 million in net proceeds.

In May 2007, EPO sold $700 million in principal amount of Junior Notes B under our universal shelf registration statement. For additional information regarding this debt offering, see Note 9.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the six months ended June 30, 2007:

	Net Proceeds from Sale of Common Units			
	Number of common units issued	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total Net Proceeds**
February DRIP and EUPP	438,631	$ 12,495	$ 255	$ 12,750
May DRIP and EUPP	494,169	15,181	622	15,803
Total 2007	932,800	$ 27,676	$ 877	$ 28,553

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2006:

	Common Units	Restricted Common Units
Balance, December 31, 2006	431,303,193	1,105,237
Units issued in connection with DRIP and EUPP	932,800	--
Units issued in connection with equity-based awards	230,500	--
Restricted common units issued	--	620,140
Forfeiture or settlement of restricted units	--	(129,053)
Balance, June 30, 2007	432,466,493	1,596,324

Summary of Changes in Limited Partners Equity

The following table details the changes in limited partners equity since December 31, 2006:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2006	$ 6,320,577	$ 9,340	$ 6,329,917
Net income	198,010	566	198,576
Operating leases paid by EPCO	1,029	3	1,032
Cash distributions to partners	(406,778)	(1,048)	(407,826)
Net proceeds from sales of common units	27,676	--	27,676
Proceeds from exercise of unit options	7,139	--	7,139
Repurchase of restricted units and options	(512)	(1,056)	(1,568)
Unit option reimbursements to EPCO	(2,786)	--	(2,786)
Amortization of equity-based awards	1,590	3,584	5,174
Balance, June 30, 2007	$ 6,145,945	$ 11,389	$ 6,157,334

Distributions to Partners

The percentage interest of Enterprise Products GP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. 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.

We paid incentive distributions of $26.3 million and $21.0 million to Enterprise Products GP during the three months ended June 30, 2007 and 2006, respectively. During the six months ended June 30, 2007 and 2006, we paid incentive distributions of $51.6 million and $40.1 million, respectively, to Enterprise Products GP.

Our quarterly cash distributions for 2007 are presented in the following table:

	Cash Distribution History		
	Distribution per Unit	**Record Date**	**Payment Date**
1st Quarter 2007	$ 0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter 2007	$ 0.4825	Jul. 31, 2007	Aug. 9, 2007

Note 11. 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 technologies 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 financial 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 an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated 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 costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. 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 include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of 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 our customers and/or suppliers. This method of operation 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, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included 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 method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of 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, New Mexico and Wyoming. 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, including the Rocky Mountains. 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 assigned to each segment on the basis of each asset s or investment s principal operations. The principal reconciling difference 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 that 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 placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis.

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

	For the Three Months Ended June 30, 2007	2006	For the Six Months Ended June 30, 2007	2006
Revenues (1)	$ 4,212,806	$ 3,517,853	$ 7,535,660	$ 6,767,927
Less: Operating costs and expenses (1)	(3,960,672)	(3,323,585)	(7,085,151)	(6,370,448)
Add: Equity in income (loss) of unconsolidated affiliates (1)	(6,211)	8,012	(32)	12,041
Depreciation, amortization and accretion in operating costs and expenses (2)	121,161	107,952	240,653	212,768
Operating lease expense paid by EPCO (2)	527	528	1,053	1,056
Loss (gain) on sale of assets in operating costs and expenses (2)	5,737	(136)	5,664	(197)
Total segment gross operating margin	$ 373,348	$ 310,624	$ 697,847	$ 623,147

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

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

A reconciliation of our 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, 2007	2006	For the Six Months Ended June 30, 2007	2006
Total segment gross operating margin	$ 373,348	$ 310,624	$ 697,847	$ 623,147
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(121,161)	(107,952)	(240,653)	(212,768)
Operating lease expense paid by EPCO	(527)	(528)	(1,053)	(1,056)
Gain (loss) on sale of assets in operating costs and expenses	(5,737)	136	(5,664)	197
General and administrative costs	(31,361)	(16,235)	(47,991)	(29,975)
Consolidated operating income	214,562	186,045	402,486	379,545
Other expense, net	(68,528)	(52,940)	(129,958)	(109,048)
Income before provision for income taxes, minority interest				

and cumulative effect of change in accounting principle	$ 146,034	$ 133,105	$ 272,528	$ 270,497

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

	Reportable Segments					
	NGL Pipelines & Services	**Onshore Natural Gas Pipelines & Services**	**Offshore Pipelines & Services**	**Petrochemical Services**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:						
Three months ended June 30, 2007	$ 3,022,604	$ 459,202	$ 55,130	$ 539,637	$ --	$ 4,076,573
Three months ended June 30, 2006	2,553,212	308,410	29,506	513,291	--	3,404,419
Six months ended June 30, 2007	5,387,722	875,432	88,113	983,918	--	7,335,185
Six months ended June 30, 2006	4,891,908	721,411	51,858	899,241	--	6,564,418
Revenues from related parties:						
Three months ended June 30, 2007	66,155	69,101	977	--	--	136,233
Three months ended June 30, 2006	37,101	75,914	419	--	--	113,434
Six months ended June 30, 2007	76,058	123,103	1,305	9	--	200,475
Six months ended June 30, 2006	44,049	158,869	591	--	--	203,509
Intersegment and intrasegment revenues:						
Three months ended June 30, 2007	1,151,803	42,917	499	123,044	(1,318,263)	--
Three months ended June 30, 2006	1,077,547	31,588	390	103,449	(1,212,974)	--
Six months ended June 30, 2007	2,274,650	61,486	1,047	228,041	(2,565,224)	--
Six months ended June 30, 2006	1,973,792	59,729	703	186,266	(2,220,490)	--
Total revenues:						
Three months ended June 30, 2007	4,240,562	571,220	56,606	662,681	(1,318,263)	4,212,806
Three months ended June 30, 2006	3,667,860	415,912	30,315	616,740	(1,212,974)	3,517,853
Six months ended June 30, 2007	7,738,430	1,060,021	90,465	1,211,968	(2,565,224)	7,535,660
Six months ended June 30, 2006	6,909,749	940,009	53,152	1,085,507	(2,220,490)	6,767,927
Equity in income (loss) of unconsolidated affiliates:						
Three months ended June 30, 2007	1,089	1,212	(8,846)	334	--	(6,211)
Three months ended June 30, 2006	1,924	904	4,769	415	--	8,012
Six months ended June 30, 2007	1,680	2,241	(4,771)	818	--	(32)
Six months ended June 30, 2006	3,442	1,506	6,703	390	--	12,041
Gross operating margin by individual business segment and in total:						
Three months ended June 30, 2007	208,805	83,163	31,046	50,334	--	373,348
Three months ended June 30, 2006	146,414	86,651	20,515	57,044	--	310,624
Six months ended June 30, 2007	399,499	159,678	50,753	87,917	--	697,847
Six months ended June 30, 2006	317,364	183,454	37,767	84,562	--	623,147
Segment assets:						
At June 30, 2007	3,690,731	3,684,425	1,169,248	557,478	1,632,248	10,734,130
At December 31, 2006	3,249,486	3,611,974	734,659	502,345	1,734,083	9,832,547
Investments in and advances to unconsolidated affiliates (see Note 7):						
At June 30, 2007	122,488	204,290	491,188	18,125	--	836,091
At December 31, 2006	111,229	124,591	310,136	18,603	--	564,559
Intangible Assets (see Note 8):						
At June 30, 2007	391,448	369,940	142,388	46,484	--	950,260
At December 31, 2006	417,950	386,149	152,376	47,480	--	1,003,955
Goodwill (see Note 8):						
At June 30, 2007	152,701	282,121	82,135	73,690	--	590,647
At December 31, 2006	152,595	282,121	82,135	73,690	--	590,541

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services:				
Sale of NGL products	$ 2,923,058	$ 2,423,219	$ 5,114,682	$ 4,615,235
Percent of consolidated revenues	69%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	422,722	268,601	783,753	636,145
Percent of consolidated revenues	10%	8%	10%	9%
Petrochemical Services:				
Sale of petrochemical products	436,309	396,439	824,061	739,789
Percent of consolidated revenues	10%	11%	11%	11%

Note 12. 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,	
	2007	**2006**	**2007**	**2006**
Revenues from consolidated operations:				
EPCO and affiliates	$ 64,127	$ 33,448	$ 72,669	$ 39,080
Unconsolidated affiliates	72,106	79,986	127,806	164,429
Total	$ 136,233	$ 113,434	$ 200,475	$ 203,509
Operating costs and expenses:				
EPCO and affiliates	$ 74,681	$ 71,105	$ 153,354	$ 166,062
Unconsolidated affiliates	10,941	7,904	16,214	14,590
Total	$ 85,622	$ 79,009	$ 169,568	$ 180,652
General and administrative costs:				
EPCO and affiliates	$ 20,733	$ 10,830	$ 33,788	$ 21,838

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not part of our consolidated group of companies:

§ EPCO and its private company subsidiaries;
§ Enterprise Products GP, our sole general partner;
§ Enterprise GP Holdings, which owns and controls our general partner;

§ TEPPCO and TEPPCO GP, which are controlled by Enterprise GP Holdings ; and
§ the Employee Partnerships.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation; therefore, they are not part of the totals presented in the preceding table. A description of our relationship with Duncan Energy Partners is presented within this Note 12.

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, 2007, EPCO and its affiliates beneficially owned 146,317,198 (or 33.7%) of our outstanding common units, which include 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at June 30, 2007, EPCO and its affiliates beneficially owned 90.1% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of Enterprise Products GP. 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 $59.9 million and $47.3 million from us during the six months ended June 30, 2007 and 2006, respectively. These amounts include incentive distributions of $51.6 million and $40.1 million for the six months ended June 30, 2007 and 2006, respectively.

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 and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. Enterprise GP Holdings, EPCO and its private company affiliates received $185.8 million and $163.4 million in cash distributions from us during the six months ended June 30, 2007 and 2006, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of 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 a private company 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.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition.

Relationship with TEPPCO

We received $21.6 million and $11.5 million from TEPPCO during the three months ended June 30, 2007 and 2006, respectively, primarily from the sale of NGLs. We received $30.1 million and $17.0 million from TEPPCO during the six months ended June 30, 2007 and 2006, respectively, primarily from the sale of NGLs. We paid TEPPCO $2.8 million and $6.2 million for NGL pipeline transportation and storage services during the three months ended June 30, 2007 and 2006, respectively. We paid TEPPCO $9.3 million and $10.6 million for NGL pipeline transportation and storage services during the six months ended June 30, 2007 and 2006, respectively.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million that is part of the DEP South Texas NGL Pipeline System. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area. The primary term of this lease expires in

September 2007, and will continue on a month-to-month basis subject to termination by either party upon 60 days notice. This pipeline is being leased by a subsidiary of Duncan Energy Partners in connection with operations on its DEP South Texas NGL Pipeline System until construction of a parallel pipeline is completed in December 2007.

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

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we signed in February 2006. In connection with the joint venture arrangement, we and TEPPCO will continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.3 Bcf/d. The Phase V expansion is also expected to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to 2.0 Bcf/d, was completed in July 2007. The second portion of the expansion is expected to be completed by the first quarter of 2008. We will operate the Jonah Gathering System.

We manage the Phase V construction project. TEPPCO is entitled to all distributions from the joint venture until specified milestones are achieved, at which point, we will be entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and TEPPCO will share distributions based on a formula that takes into account the respective capital contributions of the parties, including expenditures by TEPPCO prior to the expansion.

Since August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $176.0 million for its share of the Phase V costs. At June 30, 2007, we had a receivable from TEPPCO of $10.9 million for additional Phase V costs incurred through June 30, 2007.

Upon completion of the expansion project and based on the formula in the joint venture partnership agreement, we expect to own an interest in Jonah of approximately 20%, with TEPPCO owning the remaining 80%. At June 30, 2007, we and TEPPCO owned an approximate 19.6% interest and 80.4% interest, respectively, in Jonah. For the six months ended June 30, 2007, our earnings sharing ratio in Jonah was 4.7% compared to TEPPCO s 95.3%.

The joint venture is governed by a management committee comprised of two representatives approved by us and two representatives appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the Audit, Conflicts and Governance Committee of our general partner and that of TEPPCO GP.

EPCO 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 (the ASA). We and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services to us. The ASA also addresses potential conflicts that may arise among us, Enterprise GP Holdings, Duncan Energy Partners and other affiliates of EPCO.

31

Relationship with Duncan Energy Partners

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. All intercompany transactions between us and Duncan Energy Partners are eliminated in the preparation of our consolidated financial statements. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners net assets and earnings are presented as a component of minority interest in our consolidated financial statements.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO s Multi-Year Revolving Credit Facility.

We contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

§ Mont Belvieu Caverns, LLC (Mont Belvieu Caverns), a recently formed subsidiary, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

§ Acadian Gas, LLC (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns our 49.5% equity interest in Evangeline;

§ Sabine Propylene Pipeline L.P. (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

§ Enterprise Lou-Tex Propylene Pipeline L.P. (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

§ South Texas NGL Pipelines, LLC (South Texas NGL), a recently formed subsidiary, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition to the 34% direct ownership interest we retained in such entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units at June 30, 2007. Accordingly, we have in effect retained a net economic interest in Duncan Energy Partners of approximately 52.7% as of June 30, 2007. EPO directs the business operations of

32

Duncan Energy Partners indirectly through its ownership and control of the general partner of Duncan Energy Partners.

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

§ We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

§ We buy natural gas from and sell natural gas to Acadian Gas in connection with its normal business activities; and

§ We are currently the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute or sell other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the two months ended June 30, 2007, we recorded $42.6 million of revenues from Energy Transfer Partners, L.P. (ETP), primarily from NGL marketing activities, and incurred $5.8 million in operating costs and expenses. We have a long-term revenue generating contract with Titan Energy Partners, L.P. (Titan), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company (ETC OLP) transport natural gas on each other s systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Our significant related party revenue and expense 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. For additional information regarding our unconsolidated affiliates, see Note 7.

See Relationship with TEPPCO within this Note 12 for a description of ongoing transactions involving our Jonah joint venture with TEPPCO.

Note 13. 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 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 performance-based phantom 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, restricted units, phantom 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 using 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 presents the allocation of net income to Enterprise Products GP for the periods indicated:

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Net income	$ 142,154	$ 126,295	$ 254,199	$ 260,072
Less incentive earnings allocations to Enterprise Products GP	(26,310)	(20,997)	(51,570)	(40,112)
Net income available after incentive earnings allocation	115,844	105,298	202,629	219,960
Multiplied by Enterprise Products GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise Products GP	$ 2,317	$ 2,106	$ 4,053	$ 4,399
Incentive earnings allocation to Enterprise Products GP	$ 26,310	$ 20,997	$ 51,570	$ 40,112
Standard earnings allocation to Enterprise Products GP	2,317	2,106	4,053	4,399
Enterprise Products GP interest in net income	$ 28,627	$ 23,103	$ 55,623	$ 44,511

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Months Ended June 30, 2007	2006	For the Six Months Ended June 30, 2007	2006
Income before change in accounting principle and Enterprise Products GP interest	$ 142,154	$ 126,295	$ 254,199	$ 258,597
Cumulative effect of change in accounting principle	--	--	--	1,475
Net income	142,154	126,295	254,199	260,072
Enterprise Products GP interest in net income	(28,627)	(23,103)	(55,623)	(44,511)
Net income available to limited partners	$ 113,527	$ 103,192	$ 198,576	$ 215,561
BASIC EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 142,154	$ 126,295	$ 254,199	$ 258,597
Cumulative effect of change in accounting principle	--	--	--	1,475
Enterprise Products GP interest in net income	(28,627)	(23,103)	(55,623)	(44,511)
Limited partners interest in net income	$ 113,527	$ 103,192	$ 198,576	$ 215,561
Denominator				
Common units	432,213	408,275	431,925	401,820
Time-vested restricted units	1,329	968	1,220	862
Total	433,542	409,243	433,145	402,682
Basic earnings per unit				
Income before change in accounting principle and Enterprise Products GP interest	$ 0.33	$ 0.31	$ 0.59	$ 0.64
Cumulative effect of change in accounting principle	--	--	--	0.01
Enterprise Products GP interest in net income	(0.07)	(0.06)	(0.13)	(0.11)
Limited partners interest in net income	$ 0.26	$ 0.25	$ 0.46	$ 0.54
DILUTED EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 142,154	$ 126,295	$ 254,199	$ 258,597
Cumulative effect of change in accounting principle	--	--	--	1,475
Enterprise Products GP interest in net income	(28,627)	(23,103)	(55,623)	(44,511)
Limited partners interest in net income	$ 113,527	$ 103,192	$ 198,576	$ 215,561
Denominator				
Common units	432,213	408,275	431,925	401,820
Time-vested restricted units	1,329	968	1,220	862
Performance-based restricted units	9	27	9	27
Incremental option units	576	234	547	241
Total	434,127	409,504	433,701	402,950
Diluted earnings per unit				
Income before change in accounting principle and Enterprise Products GP interest	$ 0.33	$ 0.31	$ 0.59	$ 0.64
Cumulative effect of change in accounting principle	--	--	--	0.01
Enterprise Products GP interest in net income	(0.07)	(0.06)	(0.13)	(0.11)
Limited partners interest in net income	$ 0.26	$ 0.25	$ 0.46	$ 0.54

Note 14. 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 are insured 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 unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, cash flows or results of operations.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO, Inc.; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include the joint venture to further expand the Jonah Gathering System entered into by TEPPCO and one of our affiliates in August 2006 and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006. The amended complaint seeks (i) rescission of these transactions or an award of rescissory damages with respect thereto; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 12 for additional information regarding our relationship with TEPPCO.

On February 13, 2007, EPO received notice from the U.S. Department of Justice (DOJ) that it was the subject of a criminal investigation related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (Magellan). EPO is the operator of this pipeline. On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division (ENRD) of the DOJ regarding this incident and a previous release of ammonia on September 27, 2004 from the same pipeline. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is pursuing a resolution acceptable to all parties. EPO is seeking defense and indemnity under the pipeline operating agreement between it and Magellan. At this time, we do not believe that a final resolution of either the criminal investigation by the DOJ or the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether. In general, such suits have not named manufacturers of this product 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 manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

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.

There have been no material changes in our operating lease commitments since December 31, 2006, except for the commitments associated with a new natural gas storage lease. In order to provide firm natural gas transportation and storage services under long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint Energy) in Houston, Texas, we entered into a 2-year agreement during the second quarter of 2007 for firm natural gas storage capacity in Texas. Our rental payments under the lease are at a fixed rate. Contingent rental payments are based upon the actual volume of natural gas we inject or withdrawal from the storage cavern over the term of the lease agreement. The incremental future minimum lease payments associated with our new natural gas storage lease are $3.7 million in 2007, $4.9 million in 2008 and $1.2 million in 2009. CenterPoint Energy will reimburse us for the costs we incur associated with this natural gas storage lease.

Lease and rental expense included in operating costs and expenses was $11.8 million and $10.0 million during the three months ended June 30, 2007 and 2006, respectively. For the six months ended June 30, 2007 and 2006, lease and rental expense included in operating costs and expenses was $19.9 million and $19.7 million, respectively.

Contractual Obligations

With the exception of the debt incurred by Duncan Energy Partners in connection with its initial public offering and the issuance of Junior Notes B by EPO, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our annual report on Form 10-K for the year ended December 31, 2006. See Note 9 for additional information regarding the debt obligations of Duncan Energy Partners and the issuance of Junior Notes B.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement with six oil and natural gas producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. The performance guaranty expired during the second quarter of 2007.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of June 30, 2007, our contingent claims against such parties were approximately $1.9 million and claims against us were approximately $33.8 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Note 15. Significant Risks and Uncertainties Weather-Related Risks

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as revenue in our Unaudited Condensed Statements of Consolidated Operations in the period of receipt.

Hurricane Ivan insurance claims. We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. We are continuing our efforts to collect residual balances and expect to complete the process during 2007.

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. We continue to pursue collection of our property damage and business interruption claims related to Hurricanes Katrina and Rita.

The following table summarizes the proceeds we received for the three and six months ended June 30, 2007 and 2006 from business interruption and property damage insurance claims with respect to certain named storms:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Business interruption proceeds:				
Hurricane Ivan	$ --	$ 2,021	$ 377	$ 12,226
Hurricane Katrina	13,199	--	13,199	--
Hurricane Rita	8,258	--	8,258	--
Other	--	--	996	--
Total proceeds	21,457	2,021	22,830	12,226
Property damage proceeds:				
Hurricane Ivan	204	--	1,273	24,104
Hurricane Katrina	6,563	--	6,563	--
Other	--	--	184	--
Total proceeds	6,767	--	8,020	24,104
Total	$ 28,224	$ 2,021	$ 30,850	$ 36,330

Note 16. Supplemental Cash Flow Information

Our Unaudited Condensed Statements of Consolidated Cash Flows are prepared 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 similar transactions, (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 property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial 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,	
	2007	**2006**
Decrease (increase) in:		
Accounts and notes receivable	$ (272,644)	$ 117,826
Inventories	1,580	(111,631)
Prepaid and other current assets	(43,145)	(48,347)
Other assets	3,308	7,601
Increase (decrease) in:		
Accounts payable	33,418	12,898
Accrued gas payable	187,642	19,402
Accrued expenses	98,219	35,911
Accrued interest	3,972	(1,248)
Other current liabilities	(16,937)	45,843
Other long-term liabilities	362	(3,563)
Net effect of changes in operating accounts	$ (4,225)	$ 74,692

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $48.6 million and $34.9 million as contributions in aid of our construction costs during the six months ended June 30, 2007 and 2006, respectively.

Note 17. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

We guarantee the consolidated debt obligations of EPO with the exception of the Dixie revolving credit facility, Duncan Energy Partners credit facility and the senior subordinated notes assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. See Note 9 for additional information regarding our consolidated debt obligations.

39

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	June 30, 2007	December 31, 2006
ASSETS		
Current assets	$ 2,172,755	$ 1,915,937
Property, plant and equipment, net	10,734,128	9,832,547
Investments in and advances to unconsolidated affiliates, net	836,091	564,559
Intangible assets, net	950,260	1,003,955
Goodwill	590,647	590,541
Deferred tax asset	2,051	1,632
Other assets	77,630	74,103
Total	$ 15,363,562	$ 13,983,274
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	$ 2,203,066	$ 1,986,444
Long-term debt	6,259,715	5,295,590
Other long-term liabilities	126,026	99,845
Minority interest	439,812	136,249
Partners equity	6,334,943	6,465,146
Total	$ 15,363,562	$ 13,983,274
Total EPO debt obligations guaranteed by us	$ 6,108,881	$ 5,314,000

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Revenues	$ 4,212,806	$ 3,517,853	$ 7,535,660	$ 6,767,927
Costs and expenses	3,989,249	3,339,326	7,128,979	6,397,972
Equity in income (loss) of unconsolidated affiliates	(6,211)	8,012	(32)	12,041
Operating income	217,346	186,539	406,649	381,996
Other expense	(69,123)	(53,413)	(131,087)	(109,925)
Income before provision for income taxes, minority interest and change in accounting principle	148,223	133,126	275,562	272,071
Provision for income taxes	1,845	(6,272)	(6,934)	(9,164)
Income before minority interest and change in accounting principle	150,068	126,854	268,628	262,907
Minority interest	(5,778)	(534)	(11,521)	(2,733)
Income before change in accounting principle	144,290	126,320	257,107	260,174
Cumulative effect of change in accounting principle	--	--	--	1,475
Net income	$ 144,290	$ 126,320	$ 257,107	$ 261,649

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

For the three and six months ended June 30, 2007 and 2006.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and our accompanying 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, 2006. Our discussion and analysis includes the following:

§ Overview of Business.

§ Results of Operations Discusses material period-to-period variances in our Unaudited Condensed Statements of Consolidated Operations.

§ Liquidity and Capital Resources Addresses available sources of liquidity and analyzes cash flows.

§ Critical Accounting Policies Presents accounting policies that are among the most significant to the portrayal of our financial condition and results of operations.

§ Other Items Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and similar disclosures.

This discussion contains various forward-looking statements and information that are based on our beliefs and those of 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, could, 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 reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A, Risk Factors, included in our annual report on Form 10-K for 2006. 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.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

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

Mcf	= thousand cubic feet
TBtu	= trillion British thermal units

Our financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP).

Unless the context requires otherwise, references to we, us, our or Enterprise Products Partners are intended to mean the business and operation of Enterprise Products Partners L.P. and its consolidated subsidiaries, including Duncan Energy Partners L.P. (Duncan Energy Partners).

41

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 Texas Eastern Products Pipeline Company LLC, which is the general partner of TEPPCO and wholly owned by Enterprise GP Holdings L.P. (Enterprise GP Holdings).

Overview of Business

We are a North American midstream energy company providing 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 are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD.

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. 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 technologies employed) and products produced and/or sold.

We conduct substantially all of our business through Enterprise Products Operating LLC (EPO), as successor in interest by merger to Enterprise Products Operating L.P. 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, a publicly traded affiliate 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 the controlling shareholder of EPCO, Inc. (EPCO).

Recent Developments

The following information highlights our significant developments since January 1, 2007 through the date of this filing.

§ In August 2007, we completed the expansion of our petrochemical assets in Mont Belvieu and southeast Texas. This expansion project included (i) the construction of a fourth 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.

§ In August 2007, we completed construction of our Hobbs NGL fractionator, which is designed to handle up to 75 MBPD of mixed NGLs. The new fractionator is located at the interconnection of our Mid-America Pipeline System and our Seminole Pipeline near Hobbs, New Mexico.

§ In July 2007, our Independence Hub platform and Independence Trail pipeline received first production from deepwater production wells connected to the Independence Hub platform. As a result, these assets began earning fee-based revenues for natural gas processing and transportation services. These amounts are in addition to the demand fee revenues that Independence Hub began earning in March 2007.

§ In July 2007, we announced changes to our senior management team that became effective August 1, 2007. The board of directors of our general partner elected Michael A. Creel president and chief executive officer, W. Randall Fowler executive vice president and chief financial officer, and William Ordemann executive vice president and chief operating officer. Mr. Creel replaces Robert G. Phillips who resigned effective June 30, 2007. Mr. Fowler was promoted to fill the position left vacant by Mr. Creel s promotion. Mr. Ordemann was promoted to fill the position vacated by Dr. Ralph S. Cunningham, who is now the chief executive officer of Enterprise GP Holdings. Mr. Creel had previously held this position.

§ In July 2007, we completed the first portion of the Phase V Expansion of the Jonah Gathering System, which will increase the system gathering capacity to 2.0 Bcf/d.

§ In June 2007, we announced the completion of our project to expand the capabilities of our import/export terminal at the Houston Ship Channel to handle incremental volumes of natural gas liquids and liquefied petroleum gases.

§ In May 2007, EPO sold $700 million in principal amount of fixed/floating unsecured junior subordinated notes due January 2068. For additional information regarding this issuance of debt, see Liquidity and Capital Resources Debt Obligations included within this Item 2.

§ In March 2007, we announced the formation of a natural gas services and marketing businesses similar to our existing NGL and petrochemical marketing businesses. This new group will be the focal point for all of our existing natural gas supply and marketing activities, which currently include producer wellhead services, facility fuel procurement, pipeline and storage capacity optimization, and a full range of market customer delivery arrangements. This initiative is expected to broaden our role in the natural gas markets by linking our extensive U.S. natural gas pipeline and storage assets, thus providing customers with value-added solutions and reducing our operating costs through enhanced fuel procurement practices.

§ In February 2007, Duncan Energy Partners, a consolidated subsidiary of ours, completed an underwritten initial public offering of 14,950,000 of its common units. We formed Duncan Energy Partners as a Delaware limited partnership to acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see Other Items Initial Public Offering of Duncan Energy Partners 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 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, the Barnett Shale in North Texas, 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 expect this trend to continue, and expect independent oil and natural gas companies to consider similar divestitures.

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2007 (i.e., the third and fourth quarters) will approximate $984.0 million, which includes estimated expenditures of approximately $900.0 million for growth capital projects and acquisitions and $84.0 million for sustaining capital expenditures. For information regarding selected major growth capital projects, please see Capital Spending under Item 7 of the annual report on Form 10-K for the year ended December 31, 2006.

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 agreements, issuance of equity, and potential divestitures of certain 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, changes in our estimates 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 a 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 cash basis capital spending by activity for the periods indicated (dollars in thousands):

	For the Six Months Ended June 30,	
	2007	**2006**
Capital spending for business combinations:		
Additional ownership interests in Dixie Pipeline Company (Dixie) and other	$ 785	$ --
Total	785	--
Capital spending for property, plant and equipment:		
Growth capital projects, net	1,029,382	514,743
Sustaining capital projects	51,311	63,835
Total	1,080,693	578,578
Capital spending attributable to unconsolidated affiliates:		
Investments in and advances to unconsolidated affiliates (1)	307,032	104,762
Total	307,032	104,762
Total capital spending	$ 1,388,510	$ 683,340

(1) Includes $216.5 million in cash contributions to Cameron Highway Oil Pipeline Company (Cameron Highway) to fund our share of the repayment of its debt obligations.

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 $48.6 million and $34.9 million for the six months ended June 30, 2007 and 2006, 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 and production well tie-ins.

At June 30, 2007, we had $551.3 million in outstanding purchase commitments. These commitments primarily relate to growth capital projects in the Rocky Mountains that are expected to be placed in service in 2007 and 2008 and the Shenzi Oil Export Pipeline Project, which is expected to be completed in 2009.

We own a 50.0% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. In May 2007, we made an approximate $191.0 million cash contribution to Cameron Highway. This capital contribution, along with an equal amount contributed by our joint venture partner in Cameron Highway, was used by Cameron Highway to repay $365.0 million outstanding under its Series A notes and $14.1 million of related make-whole premiums and accrued interest. In June 2007, we and our joint venture partner in Cameron Highway, made an additional capital contribution of approximately $25.5 million each. These capital contributions were used by Cameron Highway to repay its Series B notes on June 7, 2007. The amount of the repayment was $50.9

million, which included $0.9 million of related make-whole premiums and accrued interest. As of June 30, 2007, Cameron Highway no longer has any outstanding debt.

In March 2007, we announced the successful installation of our Independence Hub platform at its deepwater site in the Mississippi Canyon of the eastern Gulf of Mexico. As a result of this event, the Independence Hub platform has started earning demand revenues. With the installation now complete, control of the Independence Hub will be transferred to Anadarko Petroleum Corporation as platform operator. First production from the fields served by the Independence Hub platform began in July 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. The following table summarizes our pipeline integrity costs for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Pipeline Integrity Costs				
Operating Expense	$ 15,349	$ 8,412	$ 23,672	$ 14,292
Capitalized	15,445	4,673	25,864	17,355
Total	$ 30,794	$ 13,085	$ 49,536	$ 31,647

We expect our net cash outlay for pipeline integrity program expenditures to approximate $29.7 million for the remainder of 2007. Our forecast is net of certain costs we expect to recover from El Paso in connection with an indemnification agreement. During the second quarter of 2007, we received $30.9 million from El Paso related to our 2006 expenditures, which leaves a remainder $0.2 million to be collected for 2006 expenditures. For the remainder of 2007, $5.4 million is reimbursable by El Paso for 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 technologies 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 financial 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 segment gross operating margin as consolidated 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 costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. 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. Intercompany accounts and transactions are eliminated in consolidation.

We include earnings from equity method 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 our 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. As circumstances dictate, we may increase our ownership interest in equity investments, which could result in their subsequent consolidation into our operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Selected Price and Volumetric Data

The following table illustrates selected quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	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)
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
3rd Quarter	$6.58	$70.44	$0.76	$1.10	$1.28	$1.30	$1.53	$0.51	$0.46
4th Quarter	$6.56	$60.03	$0.62	$0.95	$1.11	$1.12	$1.31	$0.44	$0.35
2006 Averages	$7.24	$66.09	$0.66	$1.01	$1.20	$1.24	$1.44	$0.47	$0.41
2007									
1st Quarter	$6.77	$58.02	$0.59	$0.97	$1.13	$1.22	$1.37	$0.45	$0.40
2nd Quarter	$7.55	$64.97	$0.72	$1.13	$1.33	$1.45	$1.65	$0.51	$0.46
2007 Averages	$7.16	$61.49	$0.66	$1.05	$1.23	$1.33	$1.51	$0.48	$0.43

(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). 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 in certain joint ventures, 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	
	2007	2006	2007	2006
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,696	1,586	1,652	1,515
NGL fractionation volumes (MBPD)	370	308	361	282
Equity NGL production (MBPD)	67	61	68	59
Fee-based natural gas processing (MMcf/d)	2,405	2,465	2,403	2,138
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	6,325	5,907	6,206	5,979
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,294	1,523	1,338	1,500
Crude oil transportation volumes (MBPD)	175	161	164	137
Platform gas processing (Mcf/d)	188	158	175	158
Platform oil processing (MBPD)	24	18	22	12
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	89	83	92	84
Propylene fractionation volumes (MBPD)	55	56	58	54
Octane additive production volumes (MBPD)	10	9	8	7
Petrochemical transportation volumes (MBPD)	103	93	102	90
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,974	1,840	1,918	1,742
Natural gas transportation volumes (BBtus/d)	7,619	7,430	7,544	7,479
Equivalent transportation volumes (MBPD) [(1)]	3,979	3,795	3,903	3,710

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

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,	
	2007	2006	2007	2006
Revenues	$ 4,212,806	$ 3,517,853	$ 7,535,660	$ 6,767,927
Operating costs and expenses	3,960,672	3,323,585	7,085,151	6,370,448
General and administrative costs	31,361	16,235	47,991	29,975
Equity in income (loss) of unconsolidated affiliates	(6,211)	8,012	(32)	12,041
Operating income	214,562	186,045	402,486	379,545
Interest expense	71,275	56,333	134,633	114,410
Net income	142,154	126,295	254,199	260,072

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

	For the Three Months		For the Six Months	
	Ended June 30,		Ended June 30,	
	2007	2006	2007	2006
Gross operating margin by segment:				
NGL Pipelines & Services	$ 208,805	$ 146,414	$ 399,499	$ 317,364
Onshore Natural Gas Pipelines & Services	83,163	86,651	159,678	183,454
Offshore Pipelines & Services	31,046	20,515	50,753	37,767
Petrochemical Services	50,334	57,044	87,917	84,562
Total segment gross operating margin	$ 373,348	$ 310,624	$ 697,847	$ 623,147

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

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products during the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services:				
Sale of NGL products	$ 2,923,058	$ 2,423,219	$ 5,114,682	$ 4,615,235
Percent of consolidated revenues	69%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	422,722	268,601	783,753	636,145
Percent of consolidated revenues	10%	8%	10%	9%
Petrochemical Services:				
Sale of petrochemical products	436,309	396,439	824,061	739,789
Percent of consolidated revenues	10%	11%	11%	11%

As noted in the following sections, changes in our revenues period-to-period are explained in part by changes in energy commodity prices.

Comparison of Three Months Ended June 30, 2007 with Three Months Ended June 30, 2006

Consolidated revenues increased $695.0 million quarter-to-quarter to $4.2 billion for the second quarter of 2007 from $3.5 billion for the second quarter of 2006. The quarter-to-quarter increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in the second quarter of 2007 relative to the second quarter of 2006. These factors accounted for a $693.8 million increase in consolidated revenues from our NGL, natural gas and petrochemical marketing activities. Revenues for the second quarter of 2007 include $21.5 million of proceeds from business interruption insurance associated with Hurricanes Katrina and Rita in 2005. Revenues for the second quarter of 2006 include $2.0 million of proceeds from business interruption insurance associated with Hurricane Ivan in 2004.

Operating costs and expenses were $4.0 billion for the second quarter of 2007 versus $3.3 billion for the second quarter of 2006. The $637.1 million 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 NGL, natural gas and petrochemical products increased $423.4 million quarter-to-quarter as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $37.9 million quarter-to-quarter as a result of higher energy commodity prices and processing volumes in the second quarter of 2007 compared to the second quarter of 2006. The second quarter of 2007 includes $54.0 million of consolidated operating costs and expenses attributable to businesses we acquired or assets we placed in-service after the second quarter of 2006.

General and administrative costs were $31.4 million for the second quarter of 2007 compared to $16.2 million for the second quarter of 2006. The $15.1 million quarter-to-quarter increase in general and administrative costs is primarily due to the recognition of a severance obligation to our former chief executive officer in the second quarter of 2007 and higher accounting and legal fees in the second quarter of 2007 compared to the second quarter of 2006.

Changes in our revenues and costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.13 per gallon during the second quarter of 2007 versus $1.04 per gallon during the second quarter of 2006. 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 industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $7.55 per MMBtu during the second quarter of 2007 versus $6.80 per MMBtu during the second quarter of 2006. For additional historical energy commodity pricing information, see the table on page 46.

Equity earnings from our unconsolidated affiliates were a loss of $6.2 million for the second quarter of 2007 compared to earnings of $8.0 million for the second quarter of 2006. The second quarter of 2007 includes a $7.0 million non-cash impairment charge associated with our investment in the Nemo Gathering System. Equity earnings from our investment in Cameron Highway decreased $7.3 million quarter-to-quarter primarily due to expenses we recognized during the second quarter of 2007 for the early retirement of Cameron Highway s debt. The second quarter of 2007 includes $1.1 million of equity earnings from our investment in Jonah.

Operating income for the second quarter of 2007 was $214.6 million compared to $186.0 million for the second quarter of 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $28.6 million increase in operating income quarter-to-quarter.

Interest expense increased $14.9 million quarter-to-quarter primarily due to our issuance of junior subordinated notes in the third quarter of 2006 and the second quarter of 2007. In addition, our consolidated interest expense for the second quarter of 2007 includes $2.4 million associated with Duncan Energy Partners credit facility. Our average debt principal outstanding was $6.0 billion in the second quarter of 2007 compared to $4.8 billion in the second quarter of 2006. Provision for income taxes decreased $8.1 million quarter-to-quarter primarily due to amounts recorded in the second quarter of 2006 for the initial recognition of deferred taxes associated with the Texas Margin Tax. Minority interest expense increased $5.2 million quarter-to-quarter attributable to the public unit holders of Duncan Energy Partners.

As a result of items noted in the previous paragraphs, our consolidated net income increased $15.9 million quarter-to-quarter to $142.2 million in the second quarter of 2007 compared to $126.3 million in the second quarter of 2006.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $208.8 million for the second quarter of 2007 compared to $146.4 million for the second quarter of 2006. The second quarter of 2007 includes $20.2 million of proceeds from business interruption insurance claims compared to $2.0 million of proceeds during the second quarter of 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $102.0 million for the second quarter of 2007 compared to $79.9 million for the second quarter of 2006. Equity NGL production increased to 67 MBPD during the second quarter of 2007 from 61 MBPD during the second quarter of 2006. The $22.1 million quarter-to-quarter increase in gross operating margin is primarily due to higher processing fees and equity NGL production from our Louisiana gas plants and improved results from our NGL marketing activities, which benefited from higher sales volumes and margins in the second quarter of 2007 relative to the second quarter of 2006. Gross operating margin from our Chaco natural gas processing plant increased $7.1 million quarter-to-quarter primarily due to higher volumes. Also, the second quarter of 2007 includes $2.8 million of gross operating margin from contracts we acquired in connection with the Encinal acquisition in 2006.

Gross operating margin from our NGL pipelines and related storage business was $65.7 million for the second quarter of 2007 compared to $50.6 million for the second quarter of 2006. Total NGL transportation volumes increased to 1,696 MBPD during the second quarter of 2007 from 1,586 MBPD during the second quarter of 2006. The $15.1 million quarter-to-quarter increase in gross operating margin from this business is primarily due to higher NGL transportation volumes and higher tariffs charged to shippers on our Mid-America Pipeline System during the second quarter of 2007 relative to the same quarter in 2006. Also, segment gross operating margin for the second quarter of 2007 includes $5.3 million from the DEP South Texas NGL Pipeline, which was placed in-service in January 2007.

Gross operating margin from NGL fractionation was $21.0 million for the second quarter of 2007 compared to $13.9 million for the second quarter of 2006. Fractionation volumes increased from 308 MBPD during the second quarter of 2006 to 370 MBPD during the second quarter of 2007. The $7.1 million quarter-to-quarter increase in gross operating margin is largely due to increased fractionation volumes at both our Norco and Mont Belvieu NGL fractionators. The Norco facility suffered a reduction of volumes in the second quarter of 2006 due to the lingering effects of Hurricane Katrina. Our Mont Belvieu NGL fractionator benefited from a 15 MBPD expansion project that was completed during the second quarter of 2006.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $83.2 million for the second quarter of 2007 compared to $86.7 million for the second quarter of 2006. Our onshore natural gas transportation volumes increased to 6,325 BBtu/d during the second quarter of 2007 from 5,907 BBtu/d for the second quarter of 2006. Segment gross operating margin from our onshore natural gas pipelines decreased $6.0 million quarter-to-quarter primarily due to higher pipeline integrity and maintenance costs on our Texas Intrastate System and lower natural gas sales margins. Segment gross operating margin from our San Juan Gathering System increased $4.1 million quarter-to-quarter attributable to higher revenues from certain gathering contracts in which fees are based on an index price for natural gas.

Gross operating margin for the second quarter of 2007 includes $1.3 million from the Piceance Creek Gathering System, which we acquired in December 2006 and placed in-service in January 2007. The Piceance Creek Gathering System contributed 385 BBtu/d of gathering volumes during the second quarter of 2007. The second quarter of 2007 also includes $1.1 million of equity earnings from Jonah.

In addition, gross operating margin from our natural gas storage business increased $2.5 million quarter-to-quarter largely due to the timing of repair projects at our Wilson natural gas storage facility in Texas. Our Wilson facility, which has been out of service and undergoing repairs since the second quarter of 2006, experienced mechanical problems associated with three natural gas storage caverns. We completed repairs on two of the storage caverns at our Wilson facility in the second quarter of 2007 and expect to return all three caverns to service in the second half of 2007.

Offshore Pipelines & Services. Gross operating margin from this business segment was $31.0 million for the second quarter of 2007 compared to $20.5 million for the second quarter of 2006. Segment gross operating margin for the second quarter of 2007 includes $1.3 million of proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platforms and services business was $26.8 million for the second quarter of 2007 compared to $8.2 million for the second quarter of 2006. The $18.6 million quarter-to-quarter increase in gross operating margin is primarily due to our Independence Hub platform, which started earning revenues in March 2007. In addition, gross operating margin from this business increased $4.9 million quarter-to-quarter primarily due to higher volumes in the second quarter of 2007 compared to the second quarter of 2006.

Gross operating margin from our offshore natural gas pipelines was $4.0 million for the second quarter of 2007 compared to $6.5 million for the second quarter of 2006. Offshore natural gas transportation volumes were 1,294 BBtu/d during the second quarter of 2007 versus 1,523 BBtu/d during the second quarter of 2006. The $2.5 million decrease in gross operating margin quarter-to-quarter is primarily due to a $7.0 million non-cash impairment charge in the second quarter of 2007 associated with our investment in the Nemo Gathering System and lower volumes on our Viosca Knoll Gathering System. Segment gross operating margin from our HIOS system increased $7.8 million quarter-to-quarter due to an increase in the tariff rate charged to shippers. For additional information regarding our investments in

unconsolidated affiliates, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

One of our objectives for 2006 was to seek relief through filings with the FERC to increase the tariff on our HIOS system and recover increased operating costs. In March 2007, the tariff charged to shippers on our HIOS system increased. At which time, we began collecting the increased rate (subject to refund pending FERC approval); however, revenue related to this increase was deferred. In June 2007, the new tariff on our HIOS system was uncontested by the FERC staff and all intervening shippers. Due to the uncontested status of the HIOS rate case filing, we elected to recognize $5.5 million of deferred gathering revenues in the second quarter of 2007.

Gross operating margin from our offshore crude oil pipelines decreased $6.8 million quarter-to-quarter. Segment gross operating margin for the second quarter of 2007 includes a one-time expense of $8.8 million associated with the early termination of Cameron Highway s debt. Our Marco Polo, Constitution and Poseidon oil pipelines posted higher crude oil transportation volumes during the second quarter of 2007 due to increased production activity by our customers. Collectively, gross operating margin from these oil pipelines improved $1.0 million quarter-to-quarter. Total offshore crude oil transportation volumes increased to 175 MBPD during the second quarter of 2007 from 161 MBPD during the second quarter of 2006.

Petrochemical Services. Gross operating margin from this business segment was $50.3 million for the second quarter of 2007 compared to $57.0 million for the second quarter of 2006. Gross operating margin from butane isomerization was $22.3 million for the second quarter of 2007 compared to $20.5 million for the second quarter of 2006. The quarter-to-quarter increase of $1.8 million is primarily due to higher processing volumes. Butane isomerization volumes increased to 89 MBPD during the second quarter of 2007 from 83 MBPD during the second quarter of 2006.

Gross operating margin from our octane enhancement business was $14.4 million for the second quarter of 2007 compared to $20.5 million for the second quarter of 2006. Gross operating margin from this business decreased $6.1 million quarter-to-quarter primarily due to higher maintenance costs and lower isooctane sales margins in the second quarter of 2007 versus the second quarter of 2006. Also, sales of isobutylene, which generally has lower sales margins than isooctane, increased quarter-to-quarter. Gross operating margin from our propylene fractionation and pipeline activities was $13.6 million for the second quarter of 2007 versus $16.0 million for the second quarter of 2006. The quarter-to-quarter decrease in gross operating margin of $2.4 million is largely due to lower propylene sales margins and higher power-related costs during the second quarter of 2007 compared to the second quarter of 2006.

Comparison of Six Months Ended June 30, 2007 with

Six Months Ended June 30, 2006

Revenues for the first six months of 2007 were $7.5 billion compared to $6.8 billion for the first six months of 2006. The $767.7 million period-to-period increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices during the first six months of 2007 relative to the 2006 period. These differences accounted for a $731.3 million increase in consolidated revenues associated with our marketing activities. Revenues for the first six months of 2007 include $22.8 million of proceeds from business interruption insurance associated with Hurricanes Katrina, Rita and Ivan. Revenues for the first six months of 2006 include $12.2 million of proceeds from business interruption insurance associated with Hurricane Ivan.

Operating costs and expenses were $7.1 billion for the first six months of 2007 compared to $6.4 billion for the first six months of 2006. The $714.7 million 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 $424.9 million period-to-period as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $48.9 million period-to-period as a result of higher energy commodity prices and processing volumes in the first six months of 2007 compared to the 2006 period. The first six months of 2007 include $98.7 million of consolidated operating costs and expenses attributable to businesses we acquired or assets we placed in-service after the second quarter of 2006.

General and administrative costs were $48.0 million for the first six months of 2007 compared to $30.0 million for the first six months of 2006. The $18.0 million period-to-period increase in general and administrative costs is primarily due the recognition of a severance obligation during the first six months of 2007 and an increase in accounting and legal fees.

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 for the six months ended June 30, 2007 versus $0.99 per gallon during the first six months of 2006 a period-to-period increase of 5%. The Henry Hub market price for natural gas averaged $7.16 per MMBtu for the first six months of 2007 versus $7.91 per MMBtu during the 2006 period. For additional historical energy commodity pricing information, please see the table on page 46.

Equity earnings from unconsolidated affiliates decreased $12.1 million period-to-period from $12.0 million for the first six months of 2006. The first six months of 2007 includes a $7.0 million non-cash impairment charge associated with our investment in the Nemo Gathering System. Equity earnings from our investment in Cameron Highway decreased $7.6 million period-to-period primarily due to expenses we recognized during first six months of 2007 associated with the early retirement of Cameron Highway s debt. The first six months of 2007 include $2.1 million of equity earnings from our investment in Jonah.

Operating income for the first six months of 2007 was $402.5 million compared to $379.5 million for the first six months of 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $23.0 million increase in operating income period-to-period.

Interest expense increased to $134.6 million for the first six months of 2007 from $114.4 million for the first six months of 2006. The $20.2 million period-to-period increase in interest expense is primarily due to our issuance of junior subordinated notes in the third quarter of 2006 and the second quarter of 2007. In addition, our consolidated interest expense for the first six months of 2007 includes $3.5 million associated with Duncan Energy Partners credit facility. Our average debt principal outstanding was $5.7 billion for the first six months of 2007 compared to $4.7 billion for the first six months of 2006. Provision for income taxes decreased $2.2 million period-to-period. Minority interest expense increased $8.7 million period-to-period attributable to the public unitholders of Duncan Energy Partners.

As a result of the items noted in previous paragraphs, our consolidated net income decreased $5.9 million to $254.2 million for the six months ended June 30, 2007 compared to $260.1 million for the 2006 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 2 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 $399.5 million for the first six months of 2007 compared to $317.4 million for the first six months of 2006, a period-to-period increase of $82.1 million. The first six months of 2007 include $21.6 million of proceeds from business interruption insurance claims compared to $10.3 million of proceeds during the first six months of 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $187.4 million for the first six months of 2007 compared to $161.0 million for the first six months of 2006. The $26.4 million period-to-period increase in gross operating margin is largely due to higher natural gas processing volumes during the first six months of 2007 relative to the 2006 period. Collectively, gross operating margin from our South Louisiana and Chaco natural gas processing plants increased $23.3 million attributable to higher volumes. Fee-based processing volumes increased to 2.4 Bcf/d during the first six months of 2007 from 2.1 Bcf/d during the first six months of 2006. Equity NGL production volumes increased to 68 MBPD during the first six months of 2007 from 59 MBPD during the 2006 period. Lastly, segment gross operating margin from this business for the first six months of 2007 includes $5.7 million from natural gas processing contracts we acquired in connection with the Encinal acquisition in July 2006.

Gross operating margin from NGL pipelines and storage was $144.3 million for the first six months of 2007 compared to $119.1 million for the first six months of 2006. Total NGL transportation volumes increased to 1,652 MBPD for the first six months of 2007 from 1,515 MBPD for the first six months of 2006. The $25.2 million period-to-period increase in gross operating margin is largely due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. In addition, the first six months of 2007 include $10.2 million of gross operating margin generated by the DEP South Texas NGL Pipeline.

Gross operating margin from NGL fractionation was $46.2 million for the first six months of 2007 compared to $27.0 million for the first six months of 2006. Fractionation volumes increased from 282 MBPD during the first six months of 2006 to 361 MBPD during the first six months of 2007. The period-to-period increase in gross operating margin and fractionation volumes is primarily due to our Mont Belvieu and Norco NGL fractionators. Gross operating margin from our Mont Belvieu NGL fractionator increased $10.8 million period-to-period largely due to increased demand for the fractionation of mixed NGLs. Our Norco NGL fractionator, which returned to normal operating rates in the second quarter of 2006, suffered a reduction of processing volumes during the first six months of 2006 due to the effects of Hurricane Katrina. Gross operating margin from our Norco NGL fractionator increased $10.5 million period-to-period.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $159.7 million for the first six months of 2007 compared to $183.5 million for the first six months of 2006. The $23.8 million decrease in gross operating margin period-to-period is primarily due to lower natural gas sales margins on our Acadian and Permian Basin Systems and lower gross operating margin from our Texas Intrastate System. The decrease in gross operating margin period-to-period on our Texas Intrastate System is primarily due to lower average rates realized and higher pipeline integrity and maintenance costs during the first six months of 2007 versus the 2006 period. Our onshore natural gas transportation volumes were 6,206 BBtu/d during the first six months of 2007 compared to 5,979 BBtu/d during the first six months of 2006.

The first six months of 2007 include $2.3 million of gross operating margin from our Piceance Creek Gathering System, which we placed-in service in January 2007. The Piceance Creek Gathering System contributed 336 BBtu/d of natural gas gathering volumes during the first six months of 2007. Also, the first six months of 2007 include $2.1 million of equity earnings from Jonah.

Offshore Pipelines & Services. Gross operating margin from this business segment was $50.8 million for the first six months of 2007 compared to $37.8 million for the first six months of 2006. The first six months of 2007 include $1.3 million of proceeds from business interruption insurance claims compared to $1.9 million of proceeds during the first six months of 2006. In addition, insurance costs for our offshore assets increased to $13.9 million for the first six months of 2007 compared to $7.5 million for the first six months of 2006. Insurance costs for our offshore operations have increased as a result of industry losses associated with significant storms in recent years. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims and insurance costs.

Gross operating margin from our offshore platforms and services business was $40.7 million for the first six months of 2007 compared to $14.8 million for the first six months of 2006. The $25.9 million period-to-period increase is primarily due to our Independence Hub platform, which began earning revenues in March 2007. In addition, gross operating margin from this business increased $6.4 million period-to-period primarily due to higher volumes in the first six months of 2007 compared to the 2006 period.

Gross operating margin from our offshore natural gas pipelines was $19.7 million for the first six months of 2007 compared to $21.2 million for the first six months of 2006. Offshore natural gas transportation volumes were 1,338 BBtu/d during the first six months of 2007 versus 1,500 BBtu/d during the first six months of 2006. The decrease in gross operating margin is primarily due to a $7.0 million non-cash impairment charge in the first six months of 2007 associated with our investment in the Nemo Gathering System. This decrease in gross operating margin was partially offset by the affects of a higher tariff on our HIOS system and higher volumes on our Phoenix Gathering System during the first six months of 2007 relative to the 2006 period.

Gross operating margin from our offshore crude oil pipelines was $3.0 million for the first six months of 2007 versus $7.4 million for the first six months of 2006. Improved gross operating margin period-to-period from our Marco Polo, Constitution and Poseidon Oil Pipelines was more than offset by expenses associated with the early retirement of Cameron Highway s credit facility. Segment gross operating margin for the first six months of 2007 includes a one-time expense of $8.8 million associated with the early termination of Cameron Highway s credit facility. Collectively, gross operating margin from our Marco Polo, Constitution and Poseidon Oil Pipelines increased $4.4 million period-to-period due to higher volumes. Offshore crude oil transportation volumes were 164 MBPD for the first six months of 2007 compared to 137 MBPD for the first six months of 2006.

Petrochemical Services. Gross operating margin from this business segment was $87.9 million for the first six months of 2007 compared to $84.6 million for the first six months of 2006. Gross operating margin from our octane enhancement business was $13.2 million for the first six months of 2007 compared to $9.4 million for the first six months of 2006. The $3.8 million period-to-period increase in gross operating margin is primarily due to higher isooctane sales volumes during the first six months of 2007 versus the first six months of 2006.

Gross operating margin from butane isomerization was $43.1 million for the first six months of 2007 compared to $38.6 million for the first six months of 2006. The period-to-period increase in gross operating margin of $4.5 million is largely due to higher volumes. Butane isomerization volumes increased to 92 MBPD during the first six months of 2007 from 84 MBPD during the first six months of 2006. Gross operating margin from propylene fractionation was $31.6 million for the first six months of 2007 versus $36.5 million for the first six months of 2006. The period-to-period decrease in gross operating margin of $4.9 million is largely due to lower propylene sales margins and higher power-related costs in the first six months of 2007 versus the first six months of 2006.

Significant Risks and Uncertainties Weather-Related Risks

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as revenue in our Unaudited Condensed Statements of Consolidated Operations in the period of receipt.

Hurricane Ivan insurance claims. We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. We are continuing our efforts to collect residual balances and expect to complete the process during 2007.

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. We continue to pursue collection of our property damage and business interruption claims related to Hurricanes Katrina and Rita.

The following table summarizes the proceeds we received for the three and six months ended June 30, 2007 and 2006 from business interruption and property damage insurance claims with respect to certain named storms (dollars in thousands):

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Business interruption proceeds:				
Hurricane Ivan	$ --	$ 2,021	$ 377	$ 12,226
Hurricane Katrina	13,199	--	13,199	--
Hurricane Rita	8,258	--	8,258	--
Other	--	--	996	--
Total proceeds	21,457	2,021	22,830	12,226
Property damage proceeds:				
Hurricane Ivan	204	--	1,273	24,104
Hurricane Katrina	6,563	--	6,563	--
Other	--	--	184	--
Total proceeds	6,767	--	8,020	24,104
Total proceeds	$ 28,224	$ 2,021	$ 30,850	$ 36,330

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, 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 net cash flows provided by operating activities, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interest in assets to affiliates or third parties. 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, 2007, we had $63.4 million of unrestricted cash on hand and approximately $751.0 million of available credit under EPO s Multi-Year Revolving Credit Facility. At June 30, 2007, there was approximately $108.9 million of available credit under Duncan Energy Partners Credit Facility. In total, we had approximately $6.3 billion in principal outstanding under consolidated debt agreements at June 30, 2007.

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, see Capital Spending included within this Item 2.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its 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 $4.0 billion of equity and debt securities. After taking into account the past issuance of securities under this universal registration statement, we can issue approximately $1.4 billion of additional securities under this registration statement as of August 1, 2007.

In February 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units, the majority of proceeds from which were distributed to us. Duncan Energy Partners may issue additional amounts of equity in the future in connection with other acquisitions. For additional information regarding Duncan Energy Partners, see Other Items Initial Public Offering of Duncan Energy Partners included within this Item 2.

In May 2007, EPO sold $700 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes B) under our universal shelf registration statement. For additional information regarding this debt offering, see Debt Obligations within this section.

In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 932,800 of our common units were issued in February and May 2007 in connection with the DRIP and a related plan. The issuance of these units generated $28.6 million in net proceeds.

Credit Ratings of EPO

At August 1, 2007, the investment-grade credit ratings of EPO s debt securities were Baa3 by Moody s Investor Services (Moody s); BBB- by Fitch Ratings (Fitch); and BBB- by Standard and Poor s (S&P). Fitch and S&P have assigned to us a stable outlook and Moody s has assigned to us a negative outlook due primarily to the higher debt levels at Enterprise GP Holdings followings its acquisition of limited partner interests in Energy Transfer Equity in May 2007. This acquisition increased debt at Enterprise GP Holdings that could impact the overall credit ratings for us, EPCO Holdings, Inc., Enterprise GP Holdings and TEPPCO.

56

Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, see Note 9 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, 2007	December 31, 2006
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011	$ 495,000	$ 410,000
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 (1)	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
Duncan Energy Partners debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	190,000	--
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Canadian Enterprise Revolving Credit Facility, variable rate, due October 2011	9,881	--
Other, 8.75% fixed-rate, due June 2010(2)	5,068	5,068
Total principal amount of senior debt obligations	5,063,949	4,779,068
EPO Junior Subordinated Notes A, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, due January 2068	700,000	--
Total principal amount of senior and junior debt obligations	6,313,949	5,329,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(54,234)	(33,478)
Long-term debt	$ 6,259,715	$ 5,295,590
Standby letters of credit outstanding	$ 4,000	$ 49,858

(1) In accordance with Statement of Financial Accounting Standards (SFAS) 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at June 30, 2007 and December 31, 2006. With respect to Senior Notes E due in October 2007, EPO has the ability to use cash and available credit capacity under its Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(2) Represents remaining debt obligations assumed in connection with the GulfTerra Merger.

(3) The June 30, 2007 amount includes $49.7 million related to fair value hedges and a net $4.5 million in unamortized discounts and premiums. The December 31, 2006 amount includes $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts and premiums.

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respects to the debt of Duncan Energy Partners.

Duncan Energy Partners debt obligation. Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund the $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. For additional information regarding the debt obligation of Duncan Energy Partners, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Junior Notes B. EPO sold $700 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO s payment obligations under Junior Notes B are similar to that of the junior subordinated notes due August 2066 (Junior Notes A), which were issued during the third quarter of 2006, in that they are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with the Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, commencing in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month London Interbank Offered Rate (LIBOR) for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that we nor EPO would not redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Debt obligations of unconsolidated affiliates. The following table summarizes the debt obligations of our unconsolidated affiliates (on a 100% basis to the joint venture) at June 30, 2007 and our ownership interest in each entity on that date (dollars in thousands):

	Our Ownership Interest	**Total**
Poseidon	36.0%	$ 91,000
Evangeline	49.5%	25,650
Total		$ 116,650

Previously, Cameron Highway s debt consisted of $365.0 million of Series A notes and $50.0 million of Series B notes. Cameron Highway repaid its Series A notes on May 23, 2007 using proceeds from capital contributions from its partners. The total amount of the repayment was $379.1 million, which included a $11.0 million make-whole premium and $3.1 million of accrued interest. Our share of the capital contribution was funded by borrowings under EPO s Multi-Year Revolving Credit Facility. With another capital contribution from its partners, Cameron Highway also repaid its Series B notes on June 7, 2007. The amount of the repayment was $50.9 million, which included a $0.3 million make-whole premium and $0.6 million of accrued interest. As of June 30, 2007, Cameron Highway no longer has any outstanding debt obligations.

58

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our net 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, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2007	**2006**
Net cash flows provided by operating activities	$ 552,049	$ 571,325
Net cash used in investing activities	1,387,187	689,787
Net cash provided by financing activities	876,272	100,888

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and crude oil. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from other service providers or producers due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities.

Cash used in investing activities primarily represents expenditures for capital projects, business combinations, asset purchases and investments in unconsolidated affiliates. Cash provided by (or used in) financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Unaudited Condensed Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

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

Comparison of Six Months Ended June 30, 2007 with

Six Months Ended June 30, 2006

Operating activities. Net cash flows from operating activities for the six months ended June 30, 2007 decreased $19.3 million from that recorded for the six months ended June 30, 2006. The following information highlights significant factors that influenced the period-to-period change in net cash flows from operating activities:

§ Cash flows from operating activities are influenced by the timing of cash receipts and disbursements. Our accounts payable liquidity metrics for the six months ended June 30, 2007 and 2006 are comparable and approximate our liquidity metrics for the year ended December 31, 2006. Our accounts receivable metrics for the six months ended June 30, 2007 were slightly weaker than those for the same period in 2006. Specifically, as to cash receipts, the average collection period for accounts receivable for the six months ended

June 30, 2007 was two days slower when compared to the same period in 2006, with the related turnover rate decreasing 6% period-to-period. Timing-related factors contributed to an approximate $15.1 million decrease in net cash receipts year-to-year.

§ Gross operating margin for the six months ended June 30, 2007 increased $74.7 million over that recorded for the six months ended June 30, 2006. The increase in gross operating margin is discussed under Results of Operations within this Item 2.

§ Cash distributions from unconsolidated affiliates increased $14.7 million period-to-period primarily due to higher distributions paid by Deepwater Gateway, Poseidon, and Cameron Highway. In general, distributions from our offshore projects were negatively affected during the six months ended June 30, 2006 due to the lingering effects of Hurricanes Katrina and Rita on production volumes.

Investing activities. Net cash used in investing activities was $1.4 billion for the six months ended June 30, 2007 compared to $689.8 million for the six months ended June 30, 2006. The $697.4 million increase in cash payments is primarily due to a $515.7 million increase in capital expenditures period-to-period. For additional information regarding our capital spending program, see Overview of Business Capital Spending within this Item 2. Also contributing to the increase in cash payments was capital contributions made to Cameron Highway in May and June 2007 to fund the repayment of its debt.

Financing activities. Net cash provided by financing activities was $876.3 million for the six months ended June 30, 2007 compared to net cash provided by financing activities of $100.9 million for the same period during 2006. The following information highlights significant factors that influenced the period-to-period change in net cash provided by financing activities:

§ Net borrowings under our consolidated debt agreements were $985.4 million for the six months ended June 30, 2007 and were less than $0.1 million for the six months ended June 30, 2006. At the closing of its initial public offering in February 2007, Duncan Energy Partners made an initial borrowing of $200.0 million under its $300.0 million revolving credit facility. In addition, during the second quarter of 2007, EPO sold $700.0 million in Junior Notes B. Our borrowing amounts are significantly influenced by our capital spending program.

§ Net proceeds from issuance of our common units decreased $417.6 million year-to-year. Our March 2006 underwritten equity offering generated $430.0 million in net proceeds reflecting the sale of 18,400,000 units.

§ Contributions from minority interests increased $284.5 million period-to-period primarily due to the net proceeds received from Duncan Energy Partners initial public offering in February 2007.

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, 2006. 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 the year ended December 31, 2006. 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 are 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 prospectively.

At June 30, 2007 and December 31, 2006, the net book value of our property, plant and equipment was $10.7 billion and $9.8 billion, respectively. For additional information regarding our property, plant and equipment, see 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. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

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, 2007 and December 31, 2006, the carrying value of our intangible asset portfolio was $950.3 million and $1.0 billion, respectively. For additional information regarding our intangible assets, see Note 8 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 $385.9 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, 2007 and December 31, 2006, the carrying value of our goodwill was $590.6 million and $590.5 million, respectively. For additional information regarding our goodwill, see Note 8 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 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.

In February 2007, we reserved $6.5 million in cash received from a third party to fund anticipated future environmental remediation costs associated with certain assets that we had acquired from the third party. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification was terminated.

At June 30, 2007 and December 31, 2006, our accrued liabilities for environmental remediation projects totaled $28.6 million and $24.2 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of AICPA Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities.

Natural gas imbalances

In the pipeline transportation business, natural gas imbalances frequently result from differences in gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several months. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At June 30, 2007 and December 31, 2006, our imbalance receivables, net of allowance for doubtful accounts were $64.8 million and $97.8 million, respectively, and are reflected as a component of Accounts and notes receivable trade on our Unaudited Condensed Consolidated Balance Sheets. At June 30, 2007 and December 31, 2006, our imbalance payables were $46.9 million and $51.2 million, respectively, and are reflected as a component of Accrued gas payables on our Unaudited Condensed Consolidated Balance Sheets.

Other Items

Initial Public Offering of Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in a final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO s Multi-Year Revolving Credit Facility.

In summary, we contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

§ Mont Belvieu Caverns, LLC (Mont Belvieu Caverns), a recently formed subsidiary, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

§ Acadian Gas, LLC (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns a 49.5% equity interest in Evangeline Gas Pipeline, L.P. (Evangeline);

§ Sabine Propylene Pipeline L.P. (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

§ Enterprise Lou-Tex Propylene Pipeline L.P. (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

§ South Texas NGL Pipelines, LLC (South Texas NGL), a recently formed subsidiary, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition to the 34% direct ownership interest we retained in such entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units at June 30, 2007. Accordingly, we have in effect retained a net economic interest in Duncan Energy Partners of approximately 52.7% as of June 30, 2007. EPO directs the business operations of Duncan Energy Partners indirectly through its ownership and control of the general partner of Duncan Energy Partners.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners net assets and earnings are presented as a component of minority interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant continuing involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

§ We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

§ We buy natural gas from and sell natural gas to Acadian Gas in connection with its normal business activities; and

§ We are currently the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute or sell other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

Contractual Obligations

With the exception of the debt incurred by Duncan Energy Partners in connection with its initial public offering and the issuance of Junior Notes B by EPO, there have been no significant changes in our scheduled maturities of long-term debt since those reported in our annual report on Form 10-K for the year ended December 31, 2006. See Note 9 of the Notes to the Unaudited Condensed Consolidated Financial Statements under Item 1 of this quarterly report for additional information regarding the debt obligations of Duncan Energy Partners and the issuance of Junior Notes B.

The following table presents our consolidated debt obligations and related estimates of cash interest payments after giving effect to the debt incurred by Duncan Energy Partners and EPO s issuance of Junior Notes B as of June 30, 2007 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long-term debt (1)	$ 6,313.9	$ --	$ 500.0	$ 2,213.9	$ 3,600.0
Estimated cash payments for interest (2)	8,612.0	381.6	733.3	530.6	6,966.5

(1) Represents payment obligations under our consolidated debt agreements, including those of Duncan Energy Partners as of June 30, 2007. Amounts presented in the table represent the scheduled future maturities of long-term debt principal for the periods indicated.

(2) Represents estimates of future cash payments of interest assuming that principal amounts outstanding and the interest rates charged both remain at June 30, 2007 levels.

Off-Balance Sheet Arrangements

In May 2007, we made a $191.0 million cash contribution to Cameron Highway. This capital contribution, along with an equal amount contributed by our joint venture partner in Cameron Highway, was used by Cameron Highway to repay $365.0 million outstanding under its Series A notes and $14.1 million of related make-whole premiums and accrued interest. In June 2007, we and our joint venture partner in Cameron Highway made an additional capital contribution of approximately $25.5 million each. These capital contributions were used by Cameron Highway to repay its Series B notes. The amount of the repayment was $50.9 million, which included $0.9 million of related make-whole premiums and accrued interest. As of June 30, 2007, Cameron Highway no longer has any outstanding debt.

Apart from the repayment of Cameron Highway s Series A and B notes, there have been no significant changes with regards to our off-balance sheet arrangements since those reported in our annual report on Form 10-K for the year ended December 31, 2006.

Summary of Related Party Transactions

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,	
	2007	**2006**	**2007**	**2006**
Revenues from consolidated operations:				
EPCO and affiliates	$ 64,127	$ 33,448	$ 72,669	$ 39,080
Unconsolidated affiliates	72,106	79,986	127,806	164,429
Total	$ 136,233	$ 113,434	$ 200,475	$ 203,509
Operating costs and expenses:				
EPCO and affiliates	$ 74,681	$ 71,105	$ 153,354	$ 166,062
Unconsolidated affiliates	10,941	7,904	16,214	14,590
Total	$ 85,622	$ 79,009	$ 169,568	$ 180,652
General and administrative costs:				
EPCO and affiliates	$ 20,733	$ 10,830	$ 33,788	$ 21,838

For additional information regarding our related party transactions, see Note 12 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 and Energy Transfer Equity. 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. Enterprise GP Holdings acquired non-controlling ownership interests in both ETE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

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, L.L.C. for NGL transportation, storage and fractionation services.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see Other Items Initial Public Offering of Duncan Energy Partners within this section.

65

Non-GAAP reconciliations

A reconciliation of our measurement 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 change in accounting principle follows (dollars in thousands):

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Total segment gross operating margin	$ 373,348	$ 310,624	$ 697,847	$ 623,147
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(121,161)	(107,952)	(240,653)	(212,768)
Operating lease expense paid by EPCO	(527)	(528)	(1,053)	(1,056)
Loss (gain) on sale of assets in operating costs and expenses	(5,737)	136	(5,664)	197
General and administrative costs	(31,361)	(16,235)	(47,991)	(29,975)
Consolidated operating income	214,562	186,045	402,486	379,545
Other expense, net	(68,528)	(52,940)	(129,958)	(109,048)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 146,034	$ 133,105	$ 272,528	$ 270,497

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the retained leases). These subleases are part of the administrative services agreement that we executed with EPCO 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 to us of the retained leases.

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.

Recent Accounting Pronouncements

The accounting standard setting bodies and the SEC have recently issued the following accounting guidance that will or may affect our financial statements:

- § SFAS 157, Fair Value Measurements, and
- § SFAS 159, Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115.

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. 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 applicable interest rates, commodity prices or exchange rates. 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 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, 2007 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 8.74%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.28%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.30%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.80%	$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, 2007 and December 31, 2006, was a liability of $49.7 million and $29.1 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2007 and 2006 includes a $2.3 million loss and $1.1 million loss from these swap agreements, respectively. For the six months ended June 30, 2007 and 2006, interest expense includes a loss of $4.6 million and $0.9 million, respectively, from these swap agreements.

The following table shows the effect of hypothetical price movements on the estimated fair value 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 for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	Swap Fair Value at June 30, 2007	July 24, 2007
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ (49,720)	$ (45,344)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	$ (79,392)	$ (74,663)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	$ (20,048)	$ (16,025)

Cash flow hedges Treasury locks

During the fourth quarter of 2006, EPO entered into treasury lock transactions having a notional value of $562.5 million. EPO entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during the second and fourth quarters of 2007. On February 27, 2007, EPO entered into additional treasury lock transactions having a notional value of $437.5 million. EPO entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during 2007. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133.

During the second quarter of 2007, treasury locks having a notional amount of $875.0 million were terminated. Treasury locks having a notional amount of $500.0 million were terminated concurrent with the issuance of EPO s Junior Notes B (see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report). An additional $375.0 million notional amount of treasury locks related to the anticipated issuance of debt in the fourth quarter of 2007 were also terminated. The termination of the treasury locks resulted in gains of $42.3 million, of which $10.6 million is related to EPO s Junior Notes B and the remaining $31.7 million is related to a future debt issuance. The $10.6 million gain is being amortized into income using the effective interest method as reductions to future interest expense over the fixed rate term of the Junior Notes B, which is ten years. The remaining $31.7 million gain will be amortized into income over the life of the future debt issuance using the effective interest rate method.

At June 30, 2007, there was one treasury lock outstanding which has a notional amount of $125.0 million and a fair value of $9.3 million.

In August 2007, we entered into two additional treasury locks having an aggregate $125.0 million in notional value and extending through October 15, 2007.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain 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 price 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) the value of 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. From time to time, we inject natural gas into storage and utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

At June 30, 2007 and December 31, 2006, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of cash flow hedges. The fair value of our commodity financial instrument portfolio at June 30, 2007 and December 31, 2006 was a liability of $1.0 million and $3.2 million, respectively. During the three months ended June 30, 2007 and 2006, we recorded income of $1.1 million and expense of $ 5.7 million, respectively, related to our commodity financial instruments. During the six months ended June 30, 2007 and 2006, we recorded $1.3 million and $ 5.3 million, respectively, of expense related to our commodity financial instruments.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table. The following table shows the effect of hypothetical price movements on the estimated fair value (FV) of this portfolio at the dates presented (dollars in thousands):

		Commodity Financial Instrument Portfolio FV	
Scenario	Resulting Classification	June 30, 2007	July 24, 2007

FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (1,049)	$ (4,731)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	$ 1,777	$ (2,625)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	$ (3,875)	$ (6,836)

Foreign Currency Hedging Program

We own an NGL marketing business located in Canada and have entered into construction agreements where payments are indexed to the Canadian dollar. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. Due to the limited duration of these contracts, we utilize mark-to-market accounting for these transactions, the effect of which has had a minimal impact on our earnings. At June 30, 2007, we had $3.1

million of such contracts outstanding that settled in July 2007. A 10% increase or decrease in the underlying exchange rate would have a nominal effect on our earnings.

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

Our management, with the participation of the chief executive officer (CEO) and chief financial officer (CFO) of Enterprise Products GP, 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 Enterprise Products GP 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 and (ii) accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosures. 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 14, Commitments and Contingencies Litigation, of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report, which is incorporated herein by reference.

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

In general, there have been no significant changes in our risk factors since December 31, 2006 other than the risk factor noted below. For a detailed discussion of our risk factors, please read, Item 1A Risk Factors, in our annual report on Form 10-K for 2006.

Tax Risks to Common Unitholders

We have adopted certain methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The Internal Revenue Service (IRS) may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

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

We did not repurchase any of our common units during the three months ended June 30, 2007. As of June 30, 2007, 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 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	Fourth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of February 13, 2006 (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 16, 2006).
3.3#	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007.
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).
3.6	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed

	March 31, 2003).
4.5	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.6	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.7	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.8	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.9	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.12	Agreement dated as of March 4, 2005 among Enterprise Products Partners L.P., Shell US Gas & Power LLC and Kayne Anderson MLP Investment Company (incorporated by reference to Exhibit 4.31 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.13	$750 Million 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 (incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.14	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.13, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
4.15	First Amendment dated October 5, 2005, 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 (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 7, 2005).
4.16	$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).
4.17	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.16, above (incorporated by reference to Exhibit 4.4 to Form 8-K filed on August 30, 2004).
4.18	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).
4.19	First Supplemental 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 4.2 to Form 8-K filed on October 6, 2004).
4.20	Second Supplemental 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 4.3 to Form 8-K filed on

	October 6, 2004).
4.21	Third Supplemental 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 4.4 to Form 8-K filed on October 6, 2004).
4.22	Fourth Supplemental 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 4.5 to Form 8-K filed on October 6, 2004).
4.23	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.24	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.25	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.28	Fifth Supplemental Indenture dated as of March 2, 2005, 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 4.2 to Form 8-K filed on March 3, 2005).
4.29	Sixth Supplemental Indenture dated as of March 2, 2005, 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 4.3 to Form 8-K filed on March 3, 2005).
4.30	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.31	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.32	Registration Rights Agreement dated as of March 2, 2005, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to Form 8-K filed on March 3, 2005).
4.33	Assumption Agreement dated as of September 30, 2004 between Enterprise Products Partners L.P. and GulfTerra Energy Partners, L.P. relating to the assumption by Enterprise of GulfTerra's obligations under the GulfTerra Series F2 Convertible Units (incorporated by reference to Exhibit 4.4 to Form 8-K/A-1 filed on October 5, 2004).
4.34	Statement of Rights, Privileges and Limitations of Series F Convertible Units, included as Annex A to Third Amendment to the Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P., dated May 16, 2003 (incorporated by reference to Exhibit 3.B.3 to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.35	Unitholder Agreement between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. dated May 16, 2003 (incorporated by reference to Exhibit 4.L to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.36	Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and the Chase Manhattan Bank, as

	Trustee (filed as Exhibit 4.1 to GulfTerra s Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.1 to GulfTerra s 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.2 to GulfTerra s 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (filed as Exhibit 4.E.3 to GulfTerra s 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.E.2 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.E.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.37	Seventh Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.38	Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra s Current Report of Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Second Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.1.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.39	Third Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.40	Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (filed as Exhibit 4.K to GulfTerra s Quarterly Report on Form 10-Q dated May 15, 2003); First Supplemental Indenture dated as of June 30, 2003 (filed as Exhibit 4.K.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.41	Second Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.K.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.42	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.43	Seventh Supplemental Indenture dated as of June 1, 2005, 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 4.46 to Form 10-Q filed November 4, 2005).
4.44	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.45	Note Purchase Agreement dated as of December 15, 2005 among Cameron Highway Oil Pipeline Company and the Note Purchasers listed therein (incorporated by reference to Exhibit 4.1 to Form 8-K filed December 21, 2005.)
4.46	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 (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.47	Third Amendment dated January 5, 2007, 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. (incorporated by reference to Exhibit 4.47 to Form 10-K filed February 28, 2006).
4.48	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).
4.49	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K file July 19, 2006).
4.50	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.51	Purchase Agreement dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P., as Guarantor, and Enterprise Products Partners L.P., as Buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.52	Ninth Supplemental Indenture, dated as of May 24, 2007, by and 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 the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.53	Form of Junior Subordinated Note, including Guarantee (included in Exhibit 4.52 hereto).
4.54#	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee.
4.55#	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee.
4.56#	Fourth Amendment dated June 30, 2007, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004 among Enterprise Products Operating LLC, 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.
10.1***	EPE Unit III, L.P. Agreement of Limited Partnership dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.2	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
10.3#	Agreement and Release, dated May 31, 2007, between EPCO, Inc. and Robert G. Phillips.
10.4	Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Amendment No. 2 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 12, 2007).
10.5	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007 by Duncan Energy Partners).
10.6	Second Amendment to Fourth Amended and Restated Administrative Services Agreement dated August 7, 2007, but effective as of May 7, 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.7	First Amendment to EPE Unit L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).

10.8	First Amendment to EPE Unit II, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.9	First Amendment to EPE Unit III, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2007 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the June 30, 2007 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the June 30, 2007 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the June 30, 2007 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; Enterprise GP Holdings L.P., 1-32610; and Duncan Energy Partners, L.P., 1-33266.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

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, 2007.

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