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, 2003

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

For the transition period from ________ to ________.

Commission file numbers: 1-14323
333-93239-01

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS OPERATING L.P.
(Exact name of registrants as specified in their charters)

Delaware	**76-0568219**
Delaware	**76-0568220**
(State or other jurisdiction of incorporation of organization)	(I.R.S. Employer Identification No.)

2727 North Loop West, Houston, Texas 77008-1037
(Address of principal executive offices) (Zip Code)

Registrants' telephone number, including area code: (713) 880-6500

Indicate by check mark whether the registrants: (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark if either registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

YES [X] NO [ ]

There were 210,432,070 Common Units of *Enterprise Products Partners L.P.* outstanding at August 1, 2003. Enterprise Products Partners L.P.'s Common Units trade on the New York Stock Exchange under symbol "EPD." *Enterprise Products Operating L.P.* is owned 98.9899% by its parent, EPD, and 1.0101% by the General Partner. No common equity securities of Enterprise Products Operating L.P. are publicly-traded.

EXPLANATORY NOTE

This report constitutes a combined quarterly report on Form 10-Q for Enterprise Products Partners L.P. (the "Company")(Commission File No. 1-14323) and its 98.9899% owned subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership")(Commission File No. 333-93239-01). Since the Operating Partnership owns substantially all of the Company's consolidated assets and conducts substantially all of the Company's business and operations, the information set forth herein, except for Part I, Item 1, constitutes combined information for the Company and the Operating Partnership. In accordance with Rule 3-10 of Regulation S-X, Part I, Item 1 contains separate financial statements for the Company and the Operating Partnership.

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS OPERATING L.P.
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Glossary

The following abbreviations, acronyms or terms used in this Form 10-Q are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Accum. OCI	Accumulated Other Comprehensive Income (Loss), as applicable
BBtus	Billion British thermal units, a measure of heating value
BEF	Belvieu Environmental Fuels, an equity investment of EPOLP
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment of EPOLP
BRF	Baton Rouge Fractionators LLC, an equity investment of EPOLP
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment of EPOLP
Btu	British thermal unit, a measure of heating value
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CMAI	Chemical Market Associates, Inc.
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
Diamond-Koch	Refers to affiliates of Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity investment of EPOLP
EPCO	Enterprise Products Company (including its affiliates), an affiliate of the Company and our ultimate parent company
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively, an equity investment of EPOLP until March 1, 2003, after which time it became 100% owned by EPOLP
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company

	(also referred to as the "Operating Partnership")
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment of EPOLP
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period
GAAP	Generally Accepted Accounting Principles in the United States of America
General Partner	Enterprise Products GP, LLC, the General Partner of the Company and the Operating Partnership
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment of EPOLP
MBA	Mont Belvieu Associates, see "MBA acquisition" below
MBA acquisition	Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC (we acquired an indirect 98% interest in Mid-America in July 2002)
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
Mont Belvieu Storage II	Refers to NGL and petrochemical storage businesses located in Mont Belvieu that were acquired from Diamond-Koch
Mont Belvieu Splitter III	See "Splitter III"
Moody's	Moody's Investors Service
MTBE	Methyl tertiary butyl ether
Nemo	Nemo Gathering Company, LLC, an equity investment of EPOLP
Neptune	Neptune Pipeline Company LLC, an equity investment of EPOLP
NGL or NGLs	Natural gas liquid(s)

Glossary (continued)

NYMEX	New York Merchantile Exchange
NYSE	New York Stock Exchange
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its subsidiaries
OTC	Olefins Terminal Corporation, an equity investment of the Company
Promix	K/D/S Promix LLC, an equity investment of EPOLP
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company (we acquired an indirect 78.4% interest in Seminole in July 2002)
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Starfish	Starfish Pipeline Company LLC, an equity investment of EPOLP
Throughput	Refers to the physical movement of volumes through a pipeline
Toca-Western	Refers to natural gas processing and NGL fractionation assets acquired from Western Gas Resources, Inc.
Tri-States	Tri-States NGL Pipeline LLC, an equity investment of EPOLP
Venice	Refers to natural gas processing and NGL fractionation assets owned by VESCO
Unit	Refers to limited partner interests in the Company (i.e., Common, Subordinated and Special Units)
VESCO	Venice Energy Services Company, LLC, a cost method investment of EPOLP
Williams	The Williams Companies, Inc. and subsidiaries
Wilprise	Wilprise Pipeline Company, LLC, an equity investment of EPOLP
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP

For definitions of other commonly used terms used in our industry, please refer to the “Glossary” section of our 2002 annual report on Form 10-K/A (Commission File No. 1-14323).

PART I. FINANCIAL STATEMENTS.
Item 1A. ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	June 30, 2003	December 31, 2002
ASSETS		
Current Assets		
Cash and cash equivalents (includes restricted cash of $21,532 at June 30, 2003 and $8,751 at December 31, 2002)	$ 40,505	$ 22,568
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $19,920 at June 30, 2003 and $21,196 at December 31, 2002	439,710	399,187
Accounts receivable - affiliates	206	228
Inventories	157,900	167,369
Prepaid and other current assets	25,143	48,216
Total current assets	663,464	637,568
Property, Plant and Equipment, Net	2,840,971	2,810,839
Investments in and Advances to Unconsolidated Affiliates	385,331	396,993
Intangible Assets, net of accumulated amortization of $32,724 at June 30, 2003 and $25,546 at December 31, 2002	270,483	277,661
Goodwill	81,547	81,547
Deferred Tax Asset	12,687	15,846
Long-Term Receivables	5,793	12
Other Assets	17,068	9,806
Total	$ 4,277,344	$ 4,230,272
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 15,000	$ 15,000
Accounts payable - trade	71,811	67,283
Accounts payable - affiliates	20,441	40,772
Accrued gas payables	471,373	489,562
Accrued expenses	19,700	35,760
Accrued interest	47,498	30,338
Other current liabilities	30,682	42,641
Total current liabilities	676,505	721,356
Long-Term Debt	1,859,607	2,231,463
Other Long-Term Liabilities	9,776	7,666
Minority Interest	72,400	68,883
Commitments and Contingencies		
Partners' Equity		
Common Units (179,022,202 Units outstanding at June 30, 2003 and 141,694,766 at December 31, 2002)	1,444,783	949,835
Subordinated Units (21,409,868 Units outstanding at June 30, 2003 and 32,114,804 at December 31, 2002)	66,249	116,288
Special Units (10,000,000 Units outstanding at June 30, 2003 and December 31, 2002)	143,926	143,926
Treasury Units, at cost (859,200 Common Units held at June 30, 2003 and December 31, 2002)	(17,808)	(17,808)
General Partner	16,717	12,223
Accumulated Other Comprehensive Income (Loss)	5,189	(3,560)
Total Partners' Equity	1,659,056	1,200,904
Total	$ 4,277,344	$ 4,230,272

See Notes to Unaudited Consolidated Financial Statements

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
REVENUES				
Third parties	$1,091,308	$674,812	$2,440,090	$1,246,058
Related parties	119,351	111,445	252,155	202,253
Total	1,210,659	786,257	2,692,245	1,448,311
COST AND EXPENSES				
Operating costs and expenses				
Third parties	958,999	584,323	2,111,301	1,102,372
Related parties	175,031	161,332	409,433	307,835
Selling, general and administrative costs				
Third parties	3,096	1,905	8,183	3,914
Related parties	6,957	5,835	13,341	11,788
Total	1,144,083	753,395	2,542,258	1,425,909
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	(228)	7,068	1,393	16,295
OPERATING INCOME	66,348	39,930	151,380	38,697
OTHER INCOME (EXPENSE)				
Interest expense	(33,280)	(19,032)	(75,191)	(37,545)
Dividend income from unconsolidated affiliates	1,794	1,242	4,395	2,196
Interest income - other	164	241	364	1,575
Other, net	(126)	142	(92)	224
Other income (expense)	(31,448)	(17,407)	(70,524)	(33,550)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	34,900	22,523	80,856	5,147
PROVISION FOR INCOME TAXES	(476)		(3,605)	
INCOME BEFORE MINORITY INTEREST	34,424	22,523	77,251	5,147
MINORITY INTEREST	(1,319)	(203)	(3,641)	(30)
NET INCOME	33,105	22,320	73,610	5,117
Reclassification of change in value of financial instruments recorded as cash flow hedges			3,560	
Gain on settlement of financial instruments recorded as cash flow hedges			5,354	
Amortization of gain on settlement of financial instruments to earnings	(97)		(165)	
COMPREHENSIVE INCOME	$ 33,008	$ 22,320	$ 82,359	$ 5,117
ALLOCATION OF NET INCOME TO:				
Limited partners	$ 28,028	$ 19,672	$ 64,396	$ 1,223
General partner	$ 5,077	$ 2,648	$ 9,214	$ 3,894

BASIC EARNINGS PER UNIT								
Income before minority interest	$	0.15	$	0.14	$	0.36	$	0.01
Net income	$	0.15	$	0.14	$	0.34	$	0.01
DILUTED EARNINGS PER UNIT								
Income before minority interest	$	0.15	$	0.11	$	0.34	$	0.01
Net income	$	0.14	$	0.11	$	0.32	$	0.01

See Notes to Unaudited Consolidated Financial Statements

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

	For the Six Months Ended June 30,	
	2003	**2002**
OPERATING ACTIVITIES		
Net income	$ 73,610	$ 5,117
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization in operating costs and expenses	55,502	34,198
Depreciation in selling, general and administrative costs	49	15
Amortization in interest expense	11,915	1,136
Equity in income of unconsolidated affiliates	(1,393)	(16,295)
Distributions received from unconsolidated affiliates	20,865	29,113
Operating lease expense paid by EPCO	4,502	4,534
Minority interest	3,641	30
Loss (gain) on sale of assets	(32)	12
Deferred income tax expense	5,464	
Changes in fair market value of financial instruments	(23)	19,702
Net effect of changes in operating accounts	(41,067)	(32,379)
Operating activities cash flows	133,033	45,183
INVESTING ACTIVITIES		
Capital expenditures	(54,497)	(26,755)
Proceeds from sale of assets	108	12
Business acquisitions, net of cash received	(32,702)	(394,775)
Investments in and advances to unconsolidated affiliates	(25,058)	(10,137)
Investing activities cash flows	(112,149)	(431,655)
FINANCING ACTIVITIES		
Borrowings under debt agreements	1,131,210	538,000
Repayments of debt	(1,503,000)	(170,000)
Debt issuance costs	(7,723)	(418)
Distributions paid to partners	(142,960)	(99,010)
Distributions paid to minority interests	(5,371)	(1,014)
Contributions from minority interests	5,292	86
Proceeds from issuance of Common Units	514,251	
Treasury Units purchased		(11,066)
Settlement of treasury lock financial instruments	5,354	
Increase in restricted cash	(12,781)	718
Financing activities cash flows	(15,728)	257,296

NET CHANGE IN CASH AND CASH EQUIVALENTS	5,156	(129,176)
CASH AND CASH EQUIVALENTS (NET OF RESTRICTED CASH), JANUARY 1	13,817	132,071
CASH AND CASH EQUIVALENTS (NET OF RESTRICTED CASH), JUNE 30	$ 18,973	$ 2,895

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(Dollars in thousands, see Note 9 for Unit History)

	Limited Partners						
	Common Units	**Subord. Units**	**Special Units**	**Treasury Units**	**General Partner**	**Accum. OCI**	**Total**
Balance, December 31, 2002	$ 949,835	$116,288	$143,926	$(17,808)	$ 12,223	$ (3,560)	$1,200,904
Net income	54,348	10,048			9,214		73,610
Leases paid by EPCO	3,785	672			45		4,502
Distributions paid to partners	(110,331)	(22,721)			(9,908)		(142,960)
Proceeds from issuance of Common Units in January 2003	253,107				2,557		255,664
Proceeds from issuance of Common Units in June 2003	256,001				2,586		258,587
Conversion of 10.7 million EPCO Subordinated Units to Common Units	38,038	(38,038)					
Reclassification of change in value of treasury lock financial instruments recorded as cash flow hedges						3,560	3,560
Cash gains on settlement of treasury lock financial instruments recorded as cash flow hedges						5,354	5,354
Amortization of cash gains on settlement of treasury lock financial instruments to interest expense in earnings						(165)	(165)
Balance, June 30, 2003	$1,444,783	$ 66,249	$143,926	$(17,808)	$ 16,717	$ 5,189	$1,659,056

See Notes to Unaudited Consolidated Financial Statements

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

1. GENERAL

In the opinion of Enterprise Products Partners L.P., the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation of its:

- consolidated financial position as of June 30, 2003;
- consolidated results of operations for the three and six months ended June 30, 2003 and 2002;
- consolidated cash flows for the six months ended June 30, 2003 and 2002; and
- consolidated partners' equity for the six months ended June 30, 2003.

Within these footnote disclosures of Enterprise Products Partners L.P., references to “we”, “us”, “our” or “the Company” shall mean the consolidated financial statements of Enterprise Products Partners L.P.

References to “Operating Partnership” shall mean the consolidated financial statements of our primary operating subsidiary, Enterprise Products Operating L.P., which are included elsewhere in this combined quarterly report on Form 10-Q. We own 98.9899% of the Operating Partnership and act as guarantor of certain of its debt obligations. Our General Partner, Enterprise Products GP, LLC, owns the remaining 1.0101% of the Operating Partnership. Essentially all of our assets, liabilities, revenues and expenses are recorded at the Operating Partnership level in our consolidated financial statements.

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 GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited financial statements should be read in conjunction with our annual report on Form 10-K/A (File No. 1-14323) for the year ended December 31, 2002.

The results of operations for the three and six months ended June 30, 2003 are not necessarily indicative of the results to be expected for the full year.

Dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of consolidated operations.

See Note 13 for the pro forma effect on net income and earnings per Unit if we had used the fair-value based method of accounting for Unit options.

2. RECENTLY ISSUED ACCOUNTING STANDARDS

SFAS No. 143, “*Accounting for Asset Retirement Obligations.*” We adopted this standard as of January 1, 2003. This statement establishes accounting standards for the recognition and measurement of an asset retirement obligation (“ARO”) liability and the associated asset retirement cost. Our adoption of this standard had no material impact on our financial statements. For a discussion regarding our implementation of this new standard, see Note 5.

SFAS No. 145, “*Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.*” We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting

literature to clarify its meaning, applicability and to make various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 146, “*Accounting for Costs Associated with Exit and Disposal Activities.*” We adopted this standard as of January 1, 2003. This statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of an entity's commitment to an exit or disposal plan. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 148, “Accounting for Stock-Based Compensation – Transition and Disclosure.” We adopted this standard as of December 31, 2002. This statement provides alternative methods of transition from a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 in both annual and interim financial statements. We have provided the information required by this statement under Note 13. Apart from this additional footnote disclosure, our adoption of this standard has had no material impact on our financial statements.

SFAS No. 149, “*Amendment of Statement 133 on Derivative Instruments and Hedging Activities.*” This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. This statement is effective for contracts entered into or modified after June 30, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. We are currently evaluating the effect that SFAS No. 149 will have on our financial statements.

SFAS No. 150, “Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity.” This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. The effective date of this standard for us was July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, "Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others." We implemented this FASB interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation under Note 8.

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 as of January 31, 2003 has had no material effect on our financial statements.

3. BUSINESS ACQUISITIONS

During the first six months of 2003, we acquired the Port Neches Pipeline and EPIK's remaining 50% ownership interest. We also made minor adjustments to the allocation of the purchase price we paid to acquire indirect interests in the Mid-America and Seminole pipelines. Due to the immaterial nature of each, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

Acquisition of Port Neches Pipeline. In March 2003, we acquired entities owning the Port Neches Pipeline (formerly known as the Quest Pipeline) for $14.3 million. The 70-mile Port Neches Pipeline transports high-purity grade isobutane produced at our facilities in Mont Belvieu to consumers in Port Neches, Texas.

Acquisition of remaining 50% interest in EPIK. In March 2003, we purchased the remaining 50% ownership interests in EPIK for $14.4 million (which is net of cash received

of $4.6 million). EPIK owns an NGL export terminal located in southeast Texas on the Houston Ship Channel. As a result of this acquisition, EPIK became a wholly-owned subsidiary of ours (previously, it had been an unconsolidated affiliate).

Our preliminary allocation of the purchase price of each transaction is as follows:

	50% interest in EPIK	Port Neches Pipeline	Other	Total
Prepaid and other current assets	$ 1,188	$ 44	$ (187)	$ 1,045
Property, plant and equipment	31,585	14,329	4,126	50,040
Investments in and advances to unconsolidated affiliates	(17,247)			(17,247)
Accrued expenses	(1,102)	(19)		(1,121)
Other current liabilities	(35)	(24)		(59)
Minority interest			44	44
Total purchase price	$ 14,389	$ 14,330	$ 3,983	$ 32,702

4. INVENTORIES

Our inventories were as follows at the dates indicated:

	June 30, 2003	December 31, 2002
Working inventory	$ 156,246	$ 131,769
Forward-sales inventory	1,654	35,600
Inventory	$ 157,900	$ 167,369

Our regular (or "working") inventory is comprised of inventories of NGLs, certain petrochemical products, and natural gas that are available for sale through our marketing activities. The forward sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts.

Due to fluctuating market conditions in the midstream energy industry in which we operate, we occasionally recognize lower of cost or market ("LCM") adjustments when the costs of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized. For the three and six months ended June 30, 2003, we recognized $4.0 million and $14.3 million, respectively, of such LCM adjustments. For the three and six months ended June 30, 2002, we recognized $4.5 million and $4.6 million, respectively, of these adjustments. The majority of these write-downs were taken against NGL inventories.

5. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Life in Years	June 30, 2003	December 31, 2002
Plants and pipelines	5-35	$ 2,893,080	$ 2,860,180
Underground and other storage facilities	5-35	286,938	283,114
Transportation equipment	3-35	5,416	5,118
Land		23,772	23,817
Construction in progress		93,341	49,586
Total		3,302,547	3,221,815
Less accumulated depreciation		461,576	410,976
Property, plant and equipment, net		$ 2,840,971	$ 2,810,839

Depreciation expense for the three months ended June 30, 2003 and 2002 was $24.3 million and $13.7 million, respectively. For the six months ended June 30, 2003 and 2002, it was $48.4 million and $27.9 million, respectively.

Asset retirement obligations. SFAS No. 143 establishes accounting standards for the recognition and measurement of an ARO liability and the associated asset retirement cost. Under the implementation guidelines of SFAS No. 143, we reviewed our long-lived assets for ARO liabilities and identified such liabilities in several operational areas. These include ARO liabilities related to (i) right-of-way easements over property not owned by us and (ii) regulatory requirements triggered by the abandonment or retirement of certain currently operated facilities.

As a result of our analysis of identified AROs, we were not required to recognize such potential liabilities. Our rights under the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently expect to renew all such easement agreements and to use these properties for the foreseeable future. Therefore, an ARO liability is not estimable for such easements. Should we decide not to renew these right-of-way agreements, an ARO liability would be recorded at that time. We also identified potential ARO liabilities arising from regulatory requirements related to the future abandonment or retirement of certain currently operated facilities. At present, we have no intention or legal obligation to abandon or retire such facilities. An ARO liability would be recorded if future abandonment or retirement of such facilities occurred.

Certain Gulf of Mexico natural gas pipelines owned by our equity method investees, Starfish, Neptune and Nemo, have identified ARO's relating to regulatory requirements. At present, these entities have no plans to abandon or retire their major transmission pipelines; however, there are plans to retire certain minor gas gathering lines periodically through 2013. Should the management of these companies decide to abandon or retire their major transmission pipelines, an ARO liability would be recorded at that time. With regard to the minor gas gathering pipelines scheduled for retirement, Starfish and Neptune collectively recorded ARO liabilities during 2003 totaling $2.8 million (on a gross basis).

6. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

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

	Ownership Percentage		June 30, 2003		December 31, 2002
Accounted for under the equity method:					
Fractionation:					
BRF	32.25%	$	27,729	$	28,293
BRPC	30.00%		17,126		17,616
Promix	33.33%		40,405		41,643
La Porte	50.00%		5,395		5,737
OTC	50.00%		5,558		2,178
Pipeline:					
EPIK	50.00%				11,114
Wilprise	37.35%		8,311		8,566
Tri-States	33.33%		25,476		25,552
Belle Rose	41.67%		10,784		11,057
Dixie	19.88%		37,034		36,660
Starfish	50.00%		35,745		28,512
Neptune	25.67%		75,841		77,365
Nemo	33.92%		11,904		12,423
Evangeline	49.50%		2,556		2,383
Octane Enhancement:					
BEF	33.33%		48,467		54,894
Accounted for under the cost method:					
Processing:					
VESCO	13.10%		33,000		33,000
Total		$	385,331	$	396,993

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	Ownership Percentage	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
			2003		2002		2003		2002
Fractionation:									
BRF	32.25%	$	(61)	$	743	$	81	$	1,292
BRPC	30.00%		394		278		542		527
Promix	33.33%		334		996		594		2,039
La Porte	50.00%		(153)		(173)		(334)		(265)
OTC	50.00%		65		128		(20)		18
Pipelines:									
EPIK	50.00%				(54)		1,818		1,629
Wilprise	37.35%		30		320		193		467
Tri-States	33.33%		575		365		1,124		834
Belle Rose	41.67%		(88)		40		(117)		114
Dixie	19.88%		(428)		(156)		373		561
Starfish	50.00%		1,335		973		2,484		1,785
Neptune	25.67%		684		682		694		1,460
Nemo	33.92%		258		44		594		22
Evangeline	49.50%		55		5		36		(71)
Octane Enhancement:									
BEF	33.33%		(3,228)		2,877		(6,669)		5,883
Total		$	(228)	$	7,068	$	1,393	$	16,295

The following tables present summarized income statement information for our unconsolidated affiliates accounted for under the equity method (for the periods indicated, on a 100% basis). We have grouped this information by the business segment to which the entities relate.

Summarized Income Statement Information for the Three Months Ended

	June 30, 2003			June 30, 2002		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
Pipelines	$ 91,907	$ 8,433	$ 7,357	$ 63,039	$ 5,396	$ 5,126
Fractionation	17,429	2,312	2,271	20,892	6,607	6,602
Octane Enhancement	40,637	(9,713)	(9,685)	58,132	8,570	8,629

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2003			June 30, 2002		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
Pipelines	$ 183,881	$ 29,360	$ 22,018	$ 130,886	$ 24,384	$ 19,707
Fractionation	35,543	3,836	3,776	38,932	11,959	11,974
Octane Enhancement	86,288	(20,069)	(20,007)	106,061	17,548	17,648

Our initial investment in Promix, La Porte, Dixie, Neptune and Nemo exceeded our share of the historical cost of the underlying net assets of such entities (the “excess cost”). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. That portion of excess cost attributable to the tangible plant and/or pipeline assets of each entity is amortized against equity earnings from these entities in a manner similar to depreciation. That portion of excess cost attributable to goodwill is subject to periodic impairment testing and is not amortized.

The following table summarizes our excess cost information at June 30, 2003 and December 31, 2002 by the business segment to which the unconsolidated affiliates relate:

		Original Excess Cost attributable to		Unamortized balance at	
	Amort. Periods	Tangible assets	Goodwill	June 30, 2003	December 31, 2002
Fractionation	20-35 years	$ 8,828		$ 7,208	$ 7,429
Pipelines	35 years *(1)*	41,943	$ 9,246	47,038	47,637

(1) Goodwill is not amortized; however, it is subject to periodic impairment testing.

For the three months ended June 30, 2003 and 2002, we recorded $0.4 million and $0.3 million, respectively, of excess cost amortization, which is reflected in our equity in earnings from unconsolidated affiliates. We recorded $0.8 million of excess cost amortization for each of the six month periods ended June 30, 2003 and 2002.

Purchase of remaining 50% interest in EPIK

As discussed in Note 3, we purchased the remaining 50% ownership interest in EPIK in March 2003. As a result of this acquisition, EPIK became a wholly-owned subsidiary. We recorded $1.8 million of equity income from EPIK for the two months that it was an unconsolidated subsidiary during the first quarter of 2003.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our intangible assets at June 30, 2003 and December 31, 2002:

		At June 30, 2003		At December 31, 2002	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value

Shell natural gas processing agreement	$206,216	$(28,539)	$177,677	$(23,015)	$183,201
Mont Belvieu Storage II contracts	8,127	(348)	7,779	(232)	7,895
Mont Belvieu Splitter III contracts	53,000	(2,146)	50,855	(1,388)	51,612
Toca-Western natural gas processing contracts	11,187	(606)	10,581	(326)	10,861
Toca-Western NGL fractionation contracts	20,042	(1,085)	18,956	(585)	19,457
Venice contracts (a)	4,636		4,635		4,635
Total	$303,208	$(32,724)	$270,483	$(25,546)	$277,661

(a) Amortization scheduled to begin when contracted-volumes begin to be processed in 2003.

The following table shows amortization expense associated with our intangible assets for the three and six months ended June 30, 2003 and 2002:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Shell natural gas processing agreement	$ 2,762	$ 2,762	$ 5,524	$ 5,523
Mont Belvieu Storage II contracts	58	60	116	120
Mont Belvieu Splitter III contracts	379	379	758	631
Toca-Western natural gas processing contracts	140		280	
Toca-Western NGL fractionation contracts	250		500	
Total	$ 3,589	$ 3,201	$ 7,178	$ 6,274

Goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (at June 30, 2003 and December 31, 2002):

Mont Belvieu Splitter III acquisition	$ 73,690
MBA acquisition	7,857
	$ 81,547

Our goodwill amounts are recorded as part of the Fractionation segment since they are related to assets classified within this operating segment.

8. DEBT OBLIGATIONS

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

	June 30, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003		$ 1,022,000
364-Day Revolving Credit facility, variable rate, due November 2004		99,000
Multi-Year Revolving Credit facility, variable rate, due November 2005	$ 130,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	45,000
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	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	1,879,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,652	1,774
Less unamortized discount on:		
Senior Notes A	(62)	(81)
Senior Notes B	(215)	(230)
Senior Notes D	(5,768)	
Less current maturities of debt	(15,000)	(15,000)
Long-term debt	$ 1,859,607	$ 2,231,463

Letters of credit. At June 30, 2003 and December 31, 2002, we had $75 million of standby letter of credit capacity under our Multi-Year Revolving Credit facility. We had $1.5 million of letters of credit outstanding under this facility at June 30, 2003 and $2.4 million outstanding at December 31, 2002.

Covenants. We were in compliance with the various covenants of our debt agreements at June 30, 2003 and December 31, 2002.

Parent-Subsidiary guarantor relationships. We act as guarantor of all of our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 78.4% of its ownership interests). If the Operating Partnership were to default on any of its debt we guarantee, we would be responsible for full payment of that obligation.

New senior notes issued during first quarter of 2003

During the first quarter of 2003, we completed the issuance of $850 million of long-term senior notes (Senior Notes C and D). Senior Notes C and D are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. We guarantee both Senior Notes C and D for our subsidiary through an unsecured and unsubordinated guarantee that is non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right if we elect to call the debt prior to its scheduled maturity. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes C. In January 2003, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 1, 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, we exchanged 100% of the private placement Senior Notes C for publicly-registered Senior Notes C.

Senior Notes D. In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 1, 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit facility. The remaining proceeds were used for working capital purposes. In July 2003, we exchanged 100% of the private placement Senior Notes D for publicly-registered Senior Notes D.

Repayment of 364-Day Term Loan

In July 2002, our Operating Partnership entered into the $1.2 billion senior unsecured 364-Day Term Loan to initially fund the acquisition of indirect interests in Mid-America and Seminole. We used $178.5 million of the $182.5 million in proceeds from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.2 million in proceeds from the January 2003 equity offering (see Note 9), $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our issuance of Senior Notes D to completely repay the 364-Day Term Loan by February 2003.

Revolving credit facilities

We used $60.0 million in proceeds from the issuance of Senior Notes D in February 2003 to reduce the balance outstanding under our 364-Day Revolving Credit facility. In addition, we applied $261.2 million of the net proceeds from our June 2003 equity offering (see Note 9) to reduce the balances then outstanding under our revolving credit facilities, of which $102 million was applied against the 364-Day Revolving Credit facility and $159.2 million against the Multi-Year Revolving Credit facility.

At June 30, 2003, we had $230 million of stand-alone borrowing capacity available under our 364-Day Revolving Credit facility, with no principal balance outstanding. In addition, we had $270 million in stand-alone borrowing capacity available under our Multi-Year Revolving Credit facility at June 30, 2003. We had $130 million of principal and $1.5 million in letters of credit outstanding under this facility at that date, with $138.5 million of unused capacity.

The credit line available under our 364-Day Revolving Credit facility expires in November 2003. In accordance with the terms of the credit agreement of this facility, we have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004). Management expects to refinance this facility in the fourth quarter of 2003.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations for the six months ended June 30, 2003:

	Range of interest rates paid	Weighted- average interest rate paid
364-Day Term Loan (a)	2.59% - 2.88%	2.85%
364-Day Revolving Credit facility	2.43% - 4.25%	2.52%
Multi-Year Revolving Credit facility	1.69% - 4.25%	1.96%

(a) This facility was repaid in February 2003.

9. CAPITAL STRUCTURE

Our Common Units, Subordinated Units and convertible Special Units represent limited partner interests in the Company. We are managed by our General Partner. The rights available to our partners are described in the *Third Amended and Restated Agreement of Limited Partnership* (together with any amendments thereto). Our Common Units trade on the NYSE under the symbol “EPD.”

We allocate earnings and related amounts to Common and Subordinated Unitholders and the General Partner in accordance with our partnership agreement. These classes of partnership interests are also entitled to receive cash distributions. For financial accounting and tax purposes, the Special Units are not allocated any portion of net income; however, for tax purposes, the Special Units are allocated a certain amount of depreciation until their conversion into Common Units.

In January 2003, we completed a public offering of 14,662,500 Common Units (including 1,912,500 Common Units sold pursuant to the underwriters’ over-allotment option) from which we received net proceeds before offering expenses of approximately $258.2 million, including our General Partner’s $5.2 million in capital contributions. We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under our 364-Day Term Loan (see Note 8). The remaining proceeds were used for working capital purposes and offering expenses.

In June 2003, we completed a public offering of 11,960,000 Common Units (including 1,560,000 Common Units sold pursuant to the underwriters’ over-allotment option) from which we received net proceeds before offering expenses of approximately $261.9 million, including our General Partner’s $5.3 million in capital contributions. We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities (see Note 8). The remaining proceeds were used for offering expenses.

Our partnership agreement stipulates that the Subordinated Units will undergo an early conversion to Common Units if certain criteria are satisfied. As a result of meeting the necessary criteria, 10,704,936 of EPCO’s Subordinated Units converted to Common Units on May 1, 2003.

The following table details Unit activity within each class of our limited partner interests during the six months ended June 30, 2003:

	Limited Partners			
	Common Units	Subordinated Units	Special Units	Treasury Units
Balance, December 31, 2002	141,694,766	32,114,804	10,000,000	859,200
Common Units issued in January 2003	14,662,500			
Conversion of Subordinated Units to Common Units in May 2003	10,704,936	(10,704,936)		
Common Units issued in June 2003	11,960,000			
Balance, June 30, 2003	179,022,202	21,409,868	10,000,000	859,200

The remaining 21,409,868 EPCO Subordinated Units converted to Common Units on August 1, 2003. Also, in accordance with our prior agreements with Shell, the 10,000,000 Special Units converted to Common Units on that same date.

10. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating accounts is as follows for the periods indicated:

	For the Six Months Ended June 30,	
	2003	2002
(Increase) decrease in:		
Accounts and notes receivable	$ (40,497)	$ (28,418)
Inventories	31,467	(81,381)
Prepaid and other current assets	12,969	9,599
Other assets	235	(3,436)
Increase (decrease) in:		
Accounts payable	(15,803)	7,795
Accrued gas payable	(18,189)	76,948
Accrued expenses	(17,181)	(9,499)
Accrued interest	17,160	374
Other current liabilities	(10,551)	(4,219)
Other liabilities	(677)	(142)
Net effect of changes in operating accounts	$ (41,067)	$ (32,379)

During the first six months of 2003, we completed two minor business acquisitions and made adjustments to the purchase price allocation of the Mid-America and Seminole acquisitions. These acquisitions and adjustments affected various balance sheet accounts (see Note 3). The 2002 period primarily reflects our acquisition of Diamond-Koch's Mont Belvieu NGL and petrochemical storage business in January 2002 and their adjacent propylene fractionation business (Splitter III) in February 2002.

We record certain financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. For the six months ended June 30, 2002, we recognized a net $19.7 million in non-cash mark-to-market decreases in the fair value of these instruments, primarily in our commodity financial instruments portfolio. We had a limited number of such positions outstanding during the first six months of 2003, with the non-cash change in fair value of these instruments being an increase of $23 thousand.

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash held by a brokerage firm both as margin deposits associated with our financial instruments portfolio and cash deposits pertaining to physical natural gas purchase transactions we made on the NYMEX exchange. The restricted cash balance at June 30, 2003 and December 31, 2002 was $21.5 million and $8.8 million, respectively.

During the second quarter of 2003, we recognized a $6.7 million long-term receivable from a customer relating to the construction of certain pipeline equipment. Of this amount, $3.9 million relates to charges originally recorded as construction-in-progress and $2.8 million represents deferred revenue classified as a component of other liabilities. This receivable is expected to be collected over the next ten years and bears an effective annual interest rate of approximately 12%.

11. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions, primarily within our Processing segment. In general, the types of risks we attempt to hedge are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Commodity hedging financial instruments

During the first six months of 2002, we recognized a loss of $50.9 million from our Processing segment's commodity hedging activities that was recorded as an operating cost in our Statements of Consolidated Operations and Comprehensive Income. Of this loss, $5.8 million was recorded during the second quarter of 2002. In March 2002, the effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices whereby the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During the first six months of 2003, we utilized a limited number of commodity financial instruments from which we recorded a loss of $0.9 million. Of this loss amount, $28 thousand was recognized during the second quarter of 2003. The fair value of open positions at June 30, 2003 was a payable of approximately $2 thousand.

Interest rate hedging financial instruments

During the fourth quarter of 2002, we entered into seven treasury lock transactions. Each treasury lock transaction carried a maturity date of either January 31, 2003 or April 15, 2003. The purpose of these financial instruments was to hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of debt in early 2003 to refinance the Mid-America and Seminole acquisitions. The notional amounts of the treasury lock transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

These transactions were accounted for as cash flow hedges under SFAS No. 133. The fair value of these financial instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The net $3.6 million non-cash mark-to-market liability was recorded as a component of comprehensive income on that date, with no impact on 2002 net income.

We settled all of the treasury locks by early February 2003 in connection with our issuance of Senior Notes C and D (see Note 8). The settlement of these financial instruments resulted in our receipt of $5.4 million in cash. This amount was recorded as a gain in other comprehensive income during the first quarter of 2003 and represents the effective portion of the treasury locks.

Of the $5.4 million recorded in other comprehensive income during the first quarter of 2003, $4.0 million is attributable to our issuance of Senior Notes C and is being amortized to earnings as a reduction in interest expense over the 10-year term of this debt. The remaining $1.4 million is attributable to our issuance of Senior Notes D and is being amortized to earnings as a reduction in interest expense over the 10-year term of the anticipated transaction as required by SFAS No. 133. The estimated amount to be reclassified from accumulated other comprehensive income to earnings during 2003 is $0.4 million. As a result of settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 was reclassified out of accumulated other comprehensive income in Partners' Equity to offset the current asset and liability we recorded at December 31, 2002 with no impact on 2003 net income.

12. SEGMENT INFORMATION

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Our reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the CEO of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer-grade and chemical-grade propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. We define total segment gross operating margin as operating income before:

(1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. 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 intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This non-GAAP financial 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. The GAAP measure most directly comparable to total segment gross operating margin is operating income.

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

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2003	**2002**	**2003**	**2002**
Revenues (a)	$ 1,210,659	$ 786,257	$ 2,692,245	$ 1,448,311
Less operating costs and expenses (a)	(1,134,030)	(745,655)	(2,520,734)	(1,410,207)
Add equity in income (loss) of unconsolidated affiliates (b)	(228)	7,068	1,393	16,295
Subtotal	76,401	47,670	172,904	54,399
Add: Depreciation and amortization in operating costs and expenses (c)	27,844	16,963	55,502	34,199
Retained lease expense, net in operating expenses				

allocable to us (d)	2,251	2,253	4,502	4,534
Retained lease expense, net in operating expenses allocable to our General Partner's minority interest in us (e)	23	20	45	44
Loss (gain) on sale of assets in operating costs and expenses (c)	(36)	(2)	(32)	12
Total segment gross operating margin	$ 106,483	$ 66,904	$ 232,921	$ 93,188

(a) These amounts represent both third-party and related party totals as shown on our Statements of Consolidated Operations and Comprehensive Income.
(b) This amount is taken directly from our Statements of Consolidated Operations and Comprehensive Income.
(c) This amount is taken directly from the operating activities section of our Statements of Consolidated Cash Flows.
(d) This non-cash amount represents our share of the value of the operating leases contributed by EPCO to the Operating Partnership for which EPCO has retained the cash payment obligation (the "retained leases"). This amount is taken from the operating activities section ("Operating lease expense paid to EPCO" line item) of our Statements of Consolidated Cash Flows.
(e) This non-cash amount represents a minority interest holder's share of the value of the retained leases. This amount is a component of "Contributions from minority interests" as shown in the financing activities section of our Statements of Consolidated Cash Flows.

The following table reconciles GAAP operating income as shown on our Statements of Consolidated Operations and Comprehensive Income to total segment gross operating margin for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Operating income	$ 66,348	$ 39,930	$ 151,380	$ 38,697
Adjustments to reconcile operating income to total segment gross operating margin:				
Depreciation and amortization in operating costs and expenses	27,844	16,963	55,502	34,199
Retained lease expense, net in operating costs and expenses	2,274	2,273	4,547	4,578
Loss (gain) on sale of assets in operating costs and expenses	(36)	(2)	(32)	12
Selling, general and administrative costs	10,053	7,740	21,524	15,702
Total segment gross operating margin	$ 106,483	$ 66,904	$ 232,921	$ 93,188

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

	Operating Segments						
	Fractionation	**Pipelines**	**Processing**	**Octane Enhancement**	**Other**	**Adjs. and Elims.**	**Consol. Totals**
Revenues from third parties:							
Three months ended June 30, 2003	$ 195,533	$ 180,383	$ 714,801		$ 591		$1,091,308
Three months ended June 30, 2002	163,059	99,368	412,049		336		674,812
Six months ended June 30, 2003	400,023	382,276	1,656,487		1,304		2,440,090
Six months ended June 30, 2002	266,858	175,212	803,180		808		1,246,058
Revenues from related parties:							
Three months ended June 30, 2003	650	33,349	85,352				119,351
Three months ended June 30, 2002	6,286	39,221	65,892		46		111,445

Six months ended June 30, 2003	1,273	74,054	176,828				252,155
Six months ended June 30, 2002	11,909	62,458	127,795		91		202,253
Intersegment and intrasegment revenues:							
Three months ended June 30, 2003	57,427	67,963	151,020		101	$(276,511)	
Three months ended June 30, 2002	56,103	25,578	140,969		102	(222,752)	
Six months ended June 30, 2003	142,099	103,687	338,261		202	(584,249)	
Six months ended June 30, 2002	89,500	50,088	267,229		202	(407,019)	
Total revenues:							
Three months ended June 30, 2003	253,610	281,695	951,173		692	(276,511)	1,210,659
Three months ended June 30, 2002	225,448	164,167	618,910		484	(222,752)	786,257
Six months ended June 30, 2003	543,395	560,017	2,171,576		1,506	(584,249)	2,692,245
Six months ended June 30, 2002	368,267	287,758	1,198,204		1,101	(407,019)	1,448,311
Equity in income (loss) of unconsolidated affiliates:							
Three months ended June 30, 2003	579	2,421		$ (3,228)			(228)
Three months ended June 30, 2002	1,972	2,219		2,877			7,068
Six months ended June 30, 2003	863	7,199		(6,669)			1,393
Six months ended June 30, 2002	3,611	6,801		5,883			16,295
Gross operating margin by individual business segment and in total:							
Three months ended June 30, 2003	35,871	71,969	2,685	(3,228)	(814)		106,483
Three months ended June 30, 2002	33,853	32,190	(1,182)	2,877	(834)		66,904
Six months ended June 30, 2003	64,918	143,901	32,641	(6,669)	(1,870)		232,921
Six months ended June 30, 2002	58,230	64,858	(34,558)	5,883	(1,225)		93,188
Segment assets:							
At June 30, 2003	437,808	2,127,386	164,336		18,100	93,341	2,840,971
At December 31, 2002	444,016	2,166,524	134,237		16,825	49,237	2,810,839
Investments in and advances to unconsolidated affiliates:							
At June 30, 2003	96,213	207,651	33,000	48,467			385,331
At December 31, 2002	95,467	213,632	33,000	54,894			396,993
Intangible Assets:							
At June 30, 2003	69,811	7,779	192,893				270,483
At December 31, 2002	71,069	7,895	198,697				277,661
Goodwill:							
At June 30, 2003 and December 31, 2002	81,547						81,547

Our revenues are derived from a wide customer base. All consolidated revenues during the three and six months ended June 30, 2003 and 2002 were earned in the United States. The increase in period-to-period revenues is primarily due to acquisitions and higher NGL, propylene and natural gas prices, both of which offset the effects of lower volumes at many of our pipelines and facilities.

For the three months ended June 30, 2003 and 2002, total segment gross operating margin was $106.5 million and $66.9 million, respectively. For the six month periods ended June 30, 2003 and 2002, total segment gross operating margin was $232.9 million and $93.2 million, respectively. The primary reasons for the increase in total segment gross operating margin between the periods are (a) 2003 includes gross operating margin from Mid-America and Seminole (acquired in July 2002) and (b) 2002 includes significant commodity hedging losses (see Note 11). Mid-America and Seminole's gross operating margin is classified under our Pipelines segment while commodity hedging results are primarily a function of our Processing segment activities.

13. UNIT OPTION PLAN ACCOUNTING

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the "1998 Plan"). Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our Common Units (the "Units") may be granted to EPCO's key employees who perform management, administrative or operational functions for us. The exercise price per Unit, vesting and expiration terms, and rights to receive distributions on Units granted are determined by EPCO for each grant. EPCO purchases Units under the 1998 Plan at fair value either in the open market or from us (in the form of newly-issued Common Units). In general, our responsibility for reimbursing EPCO for the expense it incurs when these options are exercised is as follows:

- We pay EPCO for the costs attributable to equity-based awards granted to operations personnel it employs on our behalf.
- We pay EPCO for the costs attributable to equity-based awards granted to administrative and management personnel it hires in response to our expansion and business activities.
- We pay EPCO for our share of the costs attributable to equity-based awards granted to certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 who manage our business and affairs. These costs are reimbursed through the administrative service fees we pay EPCO. EPCO is responsible for the actual costs of such awards when these options are exercised.

We account for our share of the cost of these awards using the intrinsic value-based method in accordance with APB No. 25, "Accounting for Stock Issued to Employees." The exercise price of each option granted is equivalent to or greater than the market price of the Unit at the date of grant. Accordingly, no compensation expense related to Unit option grants is recognized in our Statements of Consolidated Operations and Comprehensive Income.

Accounting principles require us to illustrate the pro forma effect on our net income and earnings per Unit as if the fair value-based method of accounting (based on SFAS No. 123, "Accounting for Stock Based Compensation") had been applied to the 1998 Plan. The following table shows these pro forma effects for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Historical net income	$33,105	$22,320	$73,610	$5,117
Additional Unit option-based compensation expense estimated using the fair value-based method	(171)	(273)	(342)	(546)
Pro forma net income	$32,934	$22,047	$73,268	$4,571
Basic net income per Unit:				
As reported	$ 0.15	$ 0.14	$ 0.34	$ 0.01
Pro forma	$ 0.15	$ 0.13	$ 0.34	$ 0.01
Diluted net income per Unit:				
As reported	$ 0.14	$ 0.11	$ 0.32	$ 0.01
Pro forma	$ 0.14	$ 0.11	$ 0.32	$ 0.01

14. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common and Subordinated Units outstanding during a period. In general, diluted earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common, Subordinated and Special Units outstanding during a period. In a period of net operating losses, the Special Units are excluded from the calculation of diluted earnings per Unit due to their antidilutive effect (as occurred for the first quarter of 2002). Treasury Units are not considered to be outstanding Units; therefore, they are excluded from the computation of both basic and diluted earnings per Unit.

The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for the three and six months ended June 30, 2003 and 2002:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Income before minority interest	$ 34,424	$ 22,523	$ 77,251	$ 5,147
General partner interest	(5,077)	(2,648)	(9,214)	(3,894)
Income before minority interest available to Limited Partners	29,347	19,875	68,037	1,253
Minority interest	(1,319)	(203)	(3,641)	(30)
Net income available to Limited Partners	$ 28,028	$ 19,672	$ 64,396	$ 1,223
BASIC EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$ 29,347	$ 19,875	$ 68,037	$ 1,253
Net income available to Limited Partners	$ 28,028	$ 19,672	$ 64,396	$ 1,223
Denominator				
Common Units outstanding	166,996	109,640	160,572	106,192
Subordinated Units outstanding	24,939	35,644	28,507	39,212
Total	191,935	145,284	189,079	145,404
Basic Earnings per Unit				
Income before minority interest available to Limited Partners	$ 0.15	$ 0.14	$ 0.36	$ 0.01
Net income available to Limited Partners	$ 0.15	$ 0.14	$ 0.34	$ 0.01
DILUTED EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$ 29,347	$ 19,875	$ 68,037	$ 1,253
Net income available to Limited Partners	$ 28,028	$ 19,672	$ 64,396	$ 1,223
Denominator				
Common Units outstanding	166,996	109,640	160,572	106,192
Subordinated Units outstanding	24,939	35,644	28,507	39,212
Special Units outstanding	10,000	29,000	10,000	29,000
Total	201,935	174,284	199,079	174,404
Diluted Earnings per Unit				
Income before minority interest available to Limited Partners	$ 0.15	$ 0.11	$ 0.34	$ 0.01
Net income available to Limited Partners	$ 0.14	$ 0.11	$ 0.32	$ 0.01

PART I. FINANCIAL STATEMENTS.
Item 1B. ENTERPRISE PRODUCTS OPERATING L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	June 30, 2003	December 31, 2002
ASSETS		
Current Assets		
Cash and cash equivalents (includes restricted cash of $21,532 at June 30, 2003 and $8,751 at December 31, 2002)	$ 40,503	$ 20,795
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $19,920 at June 30, 2003 and $21,196 at December 31, 2002	439,710	399,187
Accounts receivable - affiliates	413	3,369
Inventories	157,900	167,369
Prepaid and other current assets	25,036	48,137
Total current assets	663,562	638,857
Property, Plant and Equipment, Net	2,840,971	2,810,839
Investments in and Advances to Unconsolidated Affiliates	385,331	396,993
Intangible Assets, net of accumulated amortization of $32,724 at June 30, 2003 and $25,546 at December 31, 2002	270,483	277,661
Goodwill	81,547	81,547
Deferred Tax Asset	12,687	15,846
Long-Term Receivables	5,793	12
Other Assets	17,068	9,806
Total	$4,277,442	$ 4,231,561
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 15,000	$ 15,000
Accounts payable - trade	71,811	67,283
Accounts payable - affiliates	20,442	40,773
Accrued gas payables	471,373	489,562
Accrued expenses	18,998	35,760
Accrued interest	47,498	30,338
Other current liabilities	30,685	42,644
Total current liabilities	675,807	721,360
Long-Term Debt	1,859,607	2,231,463
Other Long-Term Liabilities	9,776	7,666
Minority Interest	58,226	59,336
Commitments and Contingencies		
Partners' Equity		
Limited Partner	1,660,553	1,211,593
General Partner	16,944	12,363
Parent's Units acquired by 1999 Trust	(8,660)	(8,660)
Accumulated Other Comprehensive Income (Loss)	5,189	(3,560)
Total Partners' Equity	1,674,026	1,211,736
Total	$4,277,442	$ 4,231,561

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
AND COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
REVENUES				
Revenues from consolidated operations				
Third parties	$1,091,308	$674,812	$2,440,090	$1,246,058
Related parties	119,351	111,445	252,155	202,253
Total	1,210,659	786,257	2,692,245	1,448,311
COST AND EXPENSES				
Operating costs and expenses				
Third parties	958,999	584,323	2,111,301	1,102,372
Related parties	175,031	161,332	409,433	307,835
Selling, general and administrative costs				
Third parties	3,038	1,980	7,846	3,813
Related parties	6,957	5,835	13,341	11,788
Total	1,144,025	753,470	2,541,921	1,425,808
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	(228)	7,068	1,393	16,295
OPERATING INCOME	66,406	39,855	151,717	38,798
OTHER INCOME (EXPENSE)				
Interest expense	(33,281)	(19,032)	(75,192)	(37,545)
Dividend income from unconsolidated affiliates	1,794	1,242	4,395	2,196
Interest income - other	319	384	659	1,820
Other, net	(125)	31	(89)	113
Other income (expense)	(31,293)	(17,375)	(70,227)	(33,416)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	35,113	22,480	81,490	5,382
PROVISION FOR INCOME TAXES	(476)		(3,605)	
INCOME BEFORE MINORITY INTEREST	34,637	22,480	77,885	5,382
MINORITY INTEREST	(1,060)	(33)	(2,959)	(86)
NET INCOME	33,577	22,447	74,926	5,296
Reclassification of change in value of financial instruments recorded as cash flow hedges			3,560	
Gain on settlement of financial instruments recorded as cash flow hedges			5,354	
Amortization of gain on settlement of financial instruments to earnings	(97)		(165)	
COMPREHENSIVE INCOME	$ 33,480	$ 22,447	$ 83,675	$ 5,296

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For the Six Months Ended June 30, 2003	2002
OPERATING ACTIVITIES		
Net income	$ 74,926	$ 5,296
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization in operating costs and expenses	55,502	34,198
Depreciation in selling, general and administrative costs	49	15
Amortization in interest expense	11,915	1,136
Equity in income of unconsolidated affiliates	(1,393)	(16,295)
Distributions received from unconsolidated affiliates	20,865	29,113
Operating lease expense paid by EPCO	4,547	4,579
Minority interest	2,959	86
Loss (gain) on sale of assets	(32)	12
Deferred income tax expense	5,464	
Changes in fair market value of financial instruments	(23)	19,702
Net effect of changes in operating accounts	(38,807)	(45,691)
Operating activities cash flows	135,972	32,151
INVESTING ACTIVITIES		
Capital expenditures	(54,497)	(26,755)
Proceeds from sale of assets	108	12
Business acquisitions, net of cash received	(32,702)	(394,775)
Investments in and advances to unconsolidated affiliates	(25,058)	(10,137)
Investing activities cash flows	(112,149)	(431,655)
FINANCING ACTIVITIES		
Borrowings under debt agreements	1,131,210	538,000
Repayments of debt	(1,503,000)	(170,000)
Debt issuance costs	(7,723)	(418)
Distributions paid to partners	(145,327)	(96,490)
Distributions paid to minority interests	(4,082)	
Contributions from partners	519,395	39
Contributions from minority interests	58	777
Parent’s Units acquired by consolidated Trust		(2,439)
Settlement of treasury lock financial instruments	5,354	
Increase in restricted cash	(12,781)	718
Financing activities cash flows	(16,896)	270,187
NET CHANGE IN CASH AND CASH EQUIVALENTS	6,927	(129,317)
CASH AND CASH EQUIVALENTS (NET OF RESTRICTED CASH), JANUARY 1	12,044	132,071
CASH AND CASH EQUIVALENTS (NET OF RESTRICTED CASH), JUNE 30	$ 18,971	$ 2,754

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED PARTNERS’ EQUITY

(Dollars in thousands)

	Limited Partner	General Partner	Parent's Units	Accum. OCI	Total
Balances, December 31, 2002	$1,211,593	$ 12,363	$ (8,660)	$ (3,560)	$1,211,736
Net income	74,169	757			74,926
Leases paid by EPCO	4,502	45			4,547
Contributions from partners	514,148	5,247			519,395
Distributions paid to partners	(143,859)	(1,468)			(145,327)
Reclassification of change in value of treasury lock financial instruments recorded as cash flow hedges				3,560	3,560
Cash gains on settlement of treasury lock financial instruments recorded as cash flow hedges				5,354	5,354
Amortization of cash gains on settlement of treasury lock financial instruments to interest expense in earnings				(165)	(165)
Balances, June 30, 2003	$1,660,553	$ 16,944	$ (8,660)	$ 5,189	$1,674,026

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

In the opinion of Enterprise Products Operating L.P., the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation of its:

- consolidated financial position as of June 30, 2003;
- consolidated results of operations for the three and six months ended June 30, 2003 and 2002;
- consolidated cash flows for the six months ended June 30, 2003 and 2002; and
- consolidated partners’ equity for the six months ended June 30, 2003.

Within these footnote disclosures of Enterprise Products Operating L.P., references to “we”, “us”, “our” or “the Company” shall mean the consolidated financial statements of Enterprise Products Operating L.P. References to “Limited Partner” shall mean the consolidated financial statements of our parent, Enterprise Products Partners L.P., which are included elsewhere in this combined quarterly report on Form 10-Q.

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 GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited financial statements should be read in conjunction with our annual report on Form 10-K/A (File No. 333-93239-01) for the year ended December 31, 2002.

The results of operations for the three and six months ended June 30, 2003 are not necessarily indicative of the results to be expected for the full year.

Dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

Certain reclassifications have been made to the prior years’ financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of consolidated operations.

See Note 13 for the pro forma effect on net income if we had used the fair-value based method of accounting for equity-based options.

2. RECENTLY ISSUED ACCOUNTING STANDARDS

SFAS No. 143, "*Accounting for Asset Retirement Obligations.*" We adopted this standard as of January 1, 2003. This statement establishes accounting standards for the recognition and measurement of an asset retirement obligation ("ARO") liability and the associated asset retirement cost. Our adoption of this standard had no material impact on our financial statements. For a discussion regarding our implementation of this new standard, see Note 5.

SFAS No. 145, "*Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.*" We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting literature to clarify its meaning, applicability and to make various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 146, "*Accounting for Costs Associated with Exit and Disposal Activities.*" We adopted this standard as of January 1, 2003. This statement requires companies to

recognize costs associated with exit or disposal activities when they are incurred rather than at the date of an entity's commitment to an exit or disposal plan. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." We adopted this standard as of December 31, 2002. This statement provides alternative methods of transition from a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 in both annual and interim financial statements. We have provided the information required by this statement under Note 13. Apart from this additional footnote disclosure, our adoption of this standard has had no material impact on our financial statements.

SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities.*" This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. This statement is effective for contracts entered into or modified after June 30, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. We are currently evaluating the effect that SFAS No. 149 will have on our financial statements.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. The effective date of this standard for us was July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, "*Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others*." We implemented this FASB interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation under Note 8.

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 as of January 31, 2003 has had no material effect on our financial statements.

3. BUSINESS ACQUISITIONS

During the first six months of 2003, we acquired the Port Neches Pipeline and EPIK's remaining 50% ownership interest. We also made minor adjustments to the allocation of the purchase price we paid to acquire indirect interests in the Mid-America and Seminole pipelines. Due to the immaterial nature of each, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

Acquisition of Port Neches Pipeline. In March 2003, we acquired entities owning the Port Neches Pipeline (formerly known as the Quest Pipeline) for $14.3 million. The 70-mile Port Neches Pipeline transports high-purity grade isobutane produced at our facilities in Mont Belvieu to consumers in Port Neches, Texas.

Acquisition of remaining 50% interest in EPIK. In March 2003, we purchased the remaining 50% ownership interests in EPIK for $14.4 million (which is net of cash received of $4.6 million). EPIK owns an NGL export terminal located in southeast Texas on the Houston Ship Channel. As a result of this acquisition, EPIK became a wholly-owned subsidiary of ours (previously, it had been an unconsolidated affiliate).

Our preliminary allocation of the purchase price of each transaction is as follows:

	50% interest in EPIK	Port Neches Pipeline	Other	Total
Prepaid and other current assets	$ 1,188	$ 44	$ (187)	$ 1,045
Property, plant and equipment	31,585	14,329	4,126	50,040
Investments in and advances to unconsolidated affiliates	(17,247)			(17,247)
Accrued expenses	(1,102)	(19)		(1,121)
Other current liabilities	(35)	(24)		(59)
Minority interest			44	44
Total purchase price	$ 14,389	$ 14,330	$ 3,983	$ 32,702

4. INVENTORIES

Our inventories were as follows at the dates indicated:

	June 30, 2003	December 31, 2002
Working inventory	$ 156,246	$ 131,769
Forward-sales inventory	1,654	35,600
Inventory	$ 157,900	$ 167,369

Our regular (or “working”) inventory is comprised of inventories of NGLs, certain petrochemical products, and natural gas that are available for sale through our marketing activities. The forward sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts.

Due to fluctuating market conditions in the midstream energy industry in which we operate, we occasionally recognize lower of cost or market (“LCM”) adjustments when the costs of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized. For the three and six months ended June 30, 2003, we recognized $4.0 million and $14.3 million, respectively, of such LCM adjustments. For the three and six months ended June 30, 2002, we recognized $4.5 million and $4.6 million, respectively, of these adjustments. The majority of these write-downs were taken against NGL inventories.

5. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Life in Years	June 30, 2003	December 31, 2002
Plants and pipelines	5-35	$ 2,893,080	$ 2,860,180
Underground and other storage facilities	5-35	286,938	283,114
Transportation equipment	3-35	5,416	5,118
Land		23,772	23,817
Construction in progress		93,341	49,586
Total		3,302,547	3,221,815
Less accumulated depreciation		461,576	410,976
Property, plant and equipment, net		$ 2,840,971	$ 2,810,839

Depreciation expense for the three months ended June 30, 2003 and 2002 was $24.3 million and $13.7 million, respectively. For the six months ended June 30, 2003 and 2002, it was $48.4 million and $27.9 million, respectively.

Asset retirement obligations. SFAS No. 143 establishes accounting standards for the recognition and measurement of an ARO liability and the associated asset retirement cost. Under the implementation guidelines of SFAS No. 143, we reviewed our long-lived assets for ARO liabilities and identified such liabilities in several operational areas. These include ARO liabilities related to (i) right-of-way easements over property not owned by us and (ii) regulatory requirements triggered by the abandonment or retirement of certain currently operated facilities.

As a result of our analysis of identified AROs, we were not required to recognize such potential liabilities. Our rights under the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently expect to renew all such easement agreements and to use these properties for the foreseeable future. Therefore, an ARO liability is not estimable for such easements. Should we decide not to renew these right-of-way agreements, an ARO liability would be recorded at that time. We also identified potential ARO liabilities arising from regulatory requirements related to the future abandonment or retirement of certain currently operated facilities. At present, we have no intention or legal obligation to abandon or retire such facilities. An ARO liability would be recorded if future abandonment or retirement of such facilities occurred.

Certain Gulf of Mexico natural gas pipelines owned by our equity method investees, Starfish, Neptune and Nemo, have identified ARO's relating to regulatory requirements. At present, these entities have no plans to abandon or retire their major transmission pipelines; however, there are plans to retire certain minor gas gathering lines periodically through 2013. Should the management of these companies decide to abandon or retire their major transmission pipelines, an ARO liability would be recorded at that time. With regard to the minor gas gathering pipelines scheduled for retirement, Starfish and Neptune collectively recorded ARO liabilities totaling $2.8 million (on a gross basis).

6. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

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

	Ownership Percentage	June 30, 2003	December 31, 2002
Accounted for under the equity method:			
Fractionation:			
BRF	32.25%	$ 27,729	$ 28,293
BRPC	30.00%	17,126	17,616
Promix	33.33%	40,405	41,643
La Porte	50.00%	5,395	5,737
OTC	50.00%	5,558	2,178
Pipeline:			
EPIK	50.00%		11,114
Wilprise	37.35%	8,311	8,566
Tri-States	33.33%	25,476	25,552
Belle Rose	41.67%	10,784	11,057
Dixie	19.88%	37,034	36,660
Starfish	50.00%	35,745	28,512
Neptune	25.67%	75,841	77,365
Nemo	33.92%	11,904	12,423
Evangeline	49.50%	2,556	2,383
Octane Enhancement:			
BEF	33.33%	48,467	54,894
Accounted for under the cost method:			
Processing:			
VESCO	13.10%	33,000	33,000
Total		$ 385,331	$ 396,993

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Ownership	2003	2002	2003	2002

	Percentage				
Fractionation:					
BRF	32.25%	$ (61)	$ 743	$ 81	$ 1,292
BRPC	30.00%	394	278	542	527
Promix	33.33%	334	996	594	2,039
La Porte	50.00%	(153)	(173)	(334)	(265)
OTC	50.00%	65	128	(20)	18
Pipelines:					
EPIK	50.00%		(54)	1,818	1,629
Wilprise	37.35%	30	320	193	467
Tri-States	33.33%	575	365	1,124	834
Belle Rose	41.67%	(88)	40	(117)	114
Dixie	19.88%	(428)	(156)	373	561
Starfish	50.00%	1,335	973	2,484	1,785
Neptune	25.67%	684	682	694	1,460
Nemo	33.92%	258	44	594	22
Evangeline	49.50%	55	5	36	(71)
Octane Enhancement:					
BEF	33.33%	(3,228)	2,877	(6,669)	5,883
Total		$ (228)	$ 7,068	$ 1,393	$ 16,295

The following tables present summarized income statement information for our unconsolidated affiliates accounted for under the equity method (for the periods indicated, on a 100% basis). We have grouped this information by the business segment to which the entities relate.

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2003			June 30, 2002		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
Pipelines	$ 91,907	$ 8,433	$ 7,357	$ 63,039	$ 5,396	$ 5,126
Fractionation	17,429	2,312	2,271	20,892	6,607	6,602
Octane Enhancement	40,637	(9,713)	(9,685)	58,132	8,570	8,629

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2003			June 30, 2002		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
Pipelines	$ 183,881	$ 29,360	$ 22,018	$ 130,886	$ 24,384	$ 19,707
Fractionation	35,543	3,836	3,776	38,932	11,959	11,974
Octane Enhancement	86,288	(20,069)	(20,007)	106,061	17,548	17,648

Our initial investment in Promix, La Porte, Dixie, Neptune and Nemo exceeded our share of the historical cost of the underlying net assets of such entities (the “excess cost”). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. That portion of excess cost attributable to the tangible plant and/or pipeline assets of each entity is amortized against equity earnings from these entities in a manner similar to depreciation. That portion of excess cost attributable to goodwill is subject to periodic impairment testing and is not amortized.

The following table summarizes our excess cost information at June 30, 2003 and December 31, 2002 by the business segment to which the unconsolidated affiliates relate:

		Original Excess Cost attributable to		Unamortized balance at	
	Amort. Periods	Tangible assets	Goodwill	June 30, 2003	December 31, 2002
Fractionation	20-35 years	$ 8,828		$ 7,208	$ 7,429

Pipelines	35 years *(1)*	41,943	$ 9,246	47,038	47,637

(1) Goodwill is not amortized; however, it is subject to periodic impairment testing.

For the three months ended June 30, 2003 and 2002, we recorded $0.4 million and $0.3 million, respectively, of excess cost amortization, which is reflected in our equity in earnings from unconsolidated affiliates. We recorded $0.8 million of excess cost amortization for each of the six month periods ended June 30, 2003 and 2002.

Purchase of remaining 50% interest in EPIK

As discussed in Note 3, we purchased the remaining 50% ownership interest in EPIK in March 2003. As a result of this acquisition, EPIK became a wholly-owned subsidiary. We recorded $1.8 million of equity income from EPIK for the two months that it was an unconsolidated subsidiary during the first quarter of 2003.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our intangible assets at June 30, 2003 and December 31, 2002:

		At June 30, 2003		At December 31, 2002	
	Gross Value	**Accum. Amort.**	**Carrying Value**	**Accum. Amort.**	**Carrying Value**
Shell natural gas processing agreement	$206,216	$(28,539)	$177,677	$(23,015)	$183,201
Mont Belvieu Storage II contracts	8,127	(348)	7,779	(232)	7,895
Mont Belvieu Splitter III contracts	53,000	(2,146)	50,855	(1,388)	51,612
Toca-Western natural gas processing contracts	11,187	(606)	10,581	(326)	10,861
Toca-Western NGL fractionation contracts	20,042	(1,085)	18,956	(585)	19,457
Venice contracts (a)	4,636		4,635		4,635
Total	$303,208	$(32,724)	$270,483	$(25,546)	$277,661

(a) Amortization scheduled to begin when contracted-volumes begin to be processed in 2003.

The following table shows amortization expense associated with our intangible assets for the three and six months ended June 30, 2003 and 2002:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Shell natural gas processing agreement	$ 2,762	$ 2,762	$ 5,524	$ 5,523
Mont Belvieu Storage II contracts	58	60	116	120
Mont Belvieu Splitter III contracts	379	379	758	631
Toca-Western natural gas processing contracts	140		280	
Toca-Western NGL fractionation contracts	250		500	
Total	$ 3,589	$ 3,201	$ 7,178	$ 6,274

Goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (at June 30, 2003 and December 31, 2002):

Mont Belvieu Splitter III acquisition	$ 73,690
MBA acquisition	7,857

	$ 81,547

Our goodwill amounts are recorded as part of the Fractionation segment since they are related to assets classified within this operating segment.

8. DEBT OBLIGATIONS

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

	June 30, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003		$ 1,022,000
364-Day Revolving Credit facility, variable rate, due November 2004		99,000
Multi-Year Revolving Credit facility, variable rate, due November 2005	$ 130,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	45,000
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	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	1,879,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,652	1,774
Less unamortized discount on:		
Senior Notes A	(62)	(81)
Senior Notes B	(215)	(230)
Senior Notes D	(5,768)	
Less current maturities of debt	(15,000)	(15,000)
Long-term debt	$ 1,859,607	$ 2,231,463

Letters of credit. At June 30, 2003 and December 31, 2002, we had $75 million of standby letter of credit capacity under our Multi-Year Revolving Credit facility. We had $1.5 million of letters of credit outstanding under this facility at June 30, 2003 and $2.4 million outstanding at December 31, 2002.

Covenants. We were in compliance with the various covenants of our debt agreements at June 30, 2003 and December 31, 2002.

Parent-Subsidiary guarantor relationships. Our parent (which is our Limited Partner) is the guarantor of certain of our consolidated debt obligations. This parent-subsidiary guaranty provision exists under all of our consolidated debt obligations, with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 78.4% of its ownership interests). If we were to default on any debt guaranteed by the Limited Partner, our Limited Partner would be responsible for full payment of that obligation.

New senior notes issued during first quarter of 2003

During the first quarter of 2003, we completed the issuance of $850 million of long-term senior notes (Senior Notes C and D). Senior Notes C and D are unsecured obligations and rank equally with our existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. Senior Notes C and D are guaranteed by our Limited Partner through an unsecured and unsubordinated guarantee that is non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right if we elect to call the debt prior to its scheduled maturity. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes C. In January 2003, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 1, 2013 (“Senior Notes C”), from which we received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, we exchanged 100% of the private placement Senior Notes C for publicly-registered Senior Notes C.

Senior Notes D. In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 1, 2033 (“Senior Notes D”), from which we received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit facility. The remaining proceeds were used for working capital purposes. In July 2003, we exchanged 100% of the private placement Senior Notes D for publicly-registered Senior Notes D.

Repayment of 364-Day Term Loan

In July 2002, we entered into the $1.2 billion senior unsecured 364-Day Term Loan to initially fund the acquisition of indirect interests in Mid-America and Seminole. We used $178.5 million of the $182.5 million in proceeds from our Limited Partner’s October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.2 million in proceeds from our Limited Partner’s January 2003 equity offering (see Note 9), $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our issuance of Senior Notes D to completely repay the 364-Day Term Loan by February 2003.

Revolving credit facilities

We used $60.0 million in proceeds from the issuance of Senior Notes D in February 2003 to reduce the balance outstanding under our 364-Day Revolving Credit facility. In addition, we applied $261.2 million in contributions related to our Limited Partner’s June 2003 equity offering (see Note 9) to reduce the balances then outstanding under our revolving credit facilities, of which $102 million was applied against the 364-Day Revolving Credit facility and $159.2 million against the Multi-Year Revolving Credit facility.

At June 30, 2003, we had $230 million of stand-alone borrowing capacity available under our 364-Day Revolving Credit facility, with no principal balance outstanding. In addition, we had $270 million in stand-alone borrowing capacity available under our Multi-Year Revolving Credit facility at June 30, 2003. We had $130 million of principal and $1.5 million in letters of credit outstanding under this facility at that date, with $138.5 million of unused capacity.

The credit line available under our 364-Day Revolving Credit facility expires in November 2003. In accordance with the terms of the credit agreement of this facility, we have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004). Management expects to refinance this facility in the fourth quarter of 2003.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations for the six months ended June 30, 2003:

	Range of interest rates paid	**Weighted- average interest rate paid**
364-Day Term Loan (a)	2.59% - 2.88%	2.85%
364-Day Revolving Credit facility	2.43% - 4.25%	2.52%
Multi-Year Revolving Credit facility	1.69% - 4.25%	1.96%

(a) This facility was repaid in February 2003.

9. CAPITAL STRUCTURE

We are owned 98.9899% by our Limited Partner and 1.0101% by our General Partner. The rights available to our partners are described in the *Amended and Restated Agreement of Limited Partnership.* We are managed by our General Partner.

In January 2003, our Limited Partner completed an equity offering from which we received a cash contribution of $258.2 million, which includes our General Partner's related capital contribution of $2.6 million. We used $252.8 million of the contribution to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of the contribution was used for working capital purposes.

In June 2003, our Limited Partner completed an equity offering from which we received a cash contribution of $261.2 million, which includes our General Partner's related capital contribution of $2.6 million. We used the proceeds from this contribution to reduce indebtedness outstanding under our revolving credit facilities.

10. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating accounts is as follows:

	For the Six Months Ended June 30,	
	2003	**2002**
(Increase) decrease in:		
Accounts and notes receivable	$ (37,563)	$ (38,151)
Inventories	31,467	(81,381)
Prepaid and other current assets	12,997	9,599
Other assets	235	(3,436)
Increase (decrease) in:		
Accounts payable	(15,803)	3,989
Accrued gas payable	(18,189)	76,948
Accrued expenses	(17,883)	(9,272)
Accrued interest	17,160	374
Other current liabilities	(10,551)	(4,219)
Other liabilities	(677)	(142)
Net effect of changes in operating accounts	$ (38,807)	$ (45,691)

During the first six months of 2003, we completed two minor business acquisitions and made adjustments to the purchase price allocation of the Mid-America and Seminole acquisitions. These acquisitions and adjustments affected various balance sheet accounts (see Note 3). The 2002 period primarily reflects our acquisition of Diamond-Koch's Mont Belvieu NGL and petrochemical storage business in January 2002 and their adjacent propylene fractionation business (Splitter III) in February 2002.

We record certain financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. For the six months ended June 30, 2002, we recognized a net $19.7 million in non-cash mark-to-market decreases in the fair value of these instruments, primarily in our commodity financial instruments portfolio. We had a limited number of such positions outstanding during the first six months of 2003, with the non-cash change in fair value of these instruments being an increase of $23 thousand.

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash held by a brokerage firm both as margin deposits associated with our financial instruments portfolio and cash deposits pertaining to physical natural gas purchase transactions we made on the NYMEX exchange. The restricted cash balance at June 30, 2003 and December 31, 2002 was $21.5 million and $8.8 million, respectively.

During the second quarter of 2003, we recognized a $6.7 million long-term receivable from a customer relating to the construction of certain pipeline equipment. Of this amount, $3.9 million relates to charges originally recorded as construction-in-progress and $2.8 million represents deferred revenue classified as a component of other liabilities. This receivable is expected to be collected over the next ten years and bears an effective annual interest rate of approximately 12%.

11. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions, primarily within our Processing segment. In general, the types of risks we attempt to hedge are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Commodity hedging financial instruments

During the first six months of 2002, we recognized a loss of $50.9 million from our Processing segment's commodity hedging activities that was recorded as an operating cost in our Statements of Consolidated Operations and Comprehensive Income. Of this loss, $5.8 million was recorded during the second quarter of 2002. In March 2002, the effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices whereby the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During the first six months of 2003, we utilized a limited number of commodity financial instruments from which we recorded a loss of $0.9 million. Of this loss amount, $28 thousand was recognized during the second quarter of 2003. The fair value of open positions at June 30, 2003 was a payable of approximately $2 thousand.

Interest rate hedging financial instruments

During the fourth quarter of 2002, we entered into seven treasury lock transactions. Each treasury lock transaction carried a maturity date of either January 31, 2003 or April 15, 2003. The purpose of these financial instruments was to hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of debt in early 2003 to refinance the Mid-America and Seminole acquisitions. The notional amounts of the treasury lock transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

These transactions were accounted for as cash flow hedges under SFAS No. 133. The fair value of these financial instruments at December 31, 2002 was a current liability of

$3.8 million offset by a current asset of $0.2 million. The net $3.6 million non-cash mark-to-market liability was recorded as a component of comprehensive income on that date, with no impact on 2002 net income.

We settled all of the treasury locks by early February 2003 in connection with our issuance of Senior Notes C and D (see Note 8). The settlement of these financial instruments resulted in our receipt of $5.4 million in cash. This amount was recorded as a gain in other comprehensive income during the first quarter of 2003 and represents the effective portion of the treasury locks.

Of the $5.4 million recorded in other comprehensive income during the first quarter of 2003, $4.0 million is attributable to our issuance of Senior Notes C and is being amortized to earnings as a reduction in interest expense over the 10-year term of this debt. The remaining $1.4 million is attributable to our issuance of Senior Notes D and is being amortized to earnings as a reduction in interest expense over the 10-year term of the anticipated transaction as required by SFAS No. 133. The estimated amount to be reclassified from accumulated other comprehensive income to earnings during 2003 is $0.4 million. As a result of settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 was reclassified out of accumulated other comprehensive income in Partners' Equity to offset the current asset and liability we recorded at December 31, 2002 with no impact on 2003 net income.

12. SEGMENT INFORMATION

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Our reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the CEO of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer-grade and chemical-grade propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. 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 intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This non-GAAP financial 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. The GAAP measure most directly comparable to total segment gross operating margin is operating income.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues (a)	$ 1,210,659	$ 786,257	$ 2,692,245	$ 1,448,311
Less operating costs and expenses (a)	(1,134,030)	(745,655)	(2,520,734)	(1,410,207)
Add equity in income (loss) of unconsolidated affiliates (b)	(228)	7,068	1,393	16,295
Subtotal	76,401	47,670	172,904	54,399
Add: Depreciation and amortization in operating costs and expenses (c)	27,844	16,963	55,502	34,199
Retained lease expense, net in operating expenses allocable to us (d)	2,274	2,273	4,547	4,578
Loss (gain) on sale of assets in operating costs and expenses (c)	(36)	(2)	(32)	12
Total segment gross operating margin	$ 106,483	$ 66,904	$ 232,921	$ 93,188

(a) These amounts represent both third-party and related party totals as shown on our Statements of Consolidated Operations and Comprehensive Income.
(b) This amount is taken directly from our Statements of Consolidated Operations and Comprehensive Income.
(c) This amount is taken directly from the operating activities section of our Statements of Consolidated Cash Flows.
(d) This non-cash amount represents the value of the operating leases contributed EPCO to us for which EPCO has retained the cash payment obligation (the "retained leases"). This amount is taken from the operating activities section ("Operating lease expense paid by EPCO" line item) of our Statements of Consolidated Cash Flows.

The following table reconciles GAAP operating income as shown on our Statements of Consolidated Operations and Comprehensive Income to total segment gross operating margin for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Operating income	$ 66,406	$ 39,855	$151,717	$ 38,798
Adjustments to reconcile operating income to total segment gross operating margin:				
Depreciation and amortization in operating costs and expenses	27,844	16,963	55,502	34,199
Retained lease expense, net in operating costs and expenses	2,274	2,273	4,547	4,578
Loss (gain) on sale of assets in operating costs and expenses	(36)	(2)	(32)	12
Selling, general and administrative costs	9,995	7,815	21,187	15,601
Total segment gross operating margin	$106,483	$ 66,904	$232,921	$ 93,188

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

	Operating Segments						
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	Adjs. and Elims.	Consol. Totals
Revenues from third parties:							
Three months ended June 30, 2003	$ 195,533	$ 180,383	$ 714,801		$ 591		$1,091,308
Three months ended June 30,	163,059	99,368	412,049		336		674,812

2002							
Six months ended June 30, 2003	400,023	382,276	1,656,487		1,304		2,440,090
Six months ended June 30, 2002	266,858	175,212	803,180		808		1,246,058
Revenues from related parties:							
Three months ended June 30, 2003	650	33,349	85,352				119,351
Three months ended June 30, 2002	6,286	39,221	65,892		46		111,445
Six months ended June 30, 2003	1,273	74,054	176,828				252,155
Six months ended June 30, 2002	11,909	62,458	127,795		91		202,253
Intersegment and intrasegment revenues:							
Three months ended June 30, 2003	57,427	67,963	151,020		101	$(276,511)	
Three months ended June 30, 2002	56,103	25,578	140,969		102	(222,752)	
Six months ended June 30, 2003	142,099	103,687	338,261		202	(584,249)	
Six months ended June 30, 2002	89,500	50,088	267,229		202	(407,019)	
Total revenues:							
Three months ended June 30, 2003	253,610	281,695	951,173		692	(276,511)	1,210,659
Three months ended June 30, 2002	225,448	164,167	618,910		484	(222,752)	786,257
Six months ended June 30, 2003	543,395	560,017	2,171,576		1,506	(584,249)	2,692,245
Six months ended June 30, 2002	368,267	287,758	1,198,204		1,101	(407,019)	1,448,311
Equity in income (loss) of unconsolidated affiliates:							
Three months ended June 30, 2003	579	2,421		$ (3,228)			(228)
Three months ended June 30, 2002	1,972	2,219		2,877			7,068
Six months ended June 30, 2003	863	7,199		(6,669)			1,393
Six months ended June 30, 2002	3,611	6,801		5,883			16,295
Gross operating margin by individual business segment and in total:							
Three months ended June 30, 2003	35,871	71,969	2,685	(3,228)	(814)		106,483
Three months ended June 30, 2002	33,853	32,190	(1,182)	2,877	(834)		66,904
Six months ended June 30, 2003	64,918	143,901	32,641	(6,669)	(1,870)		232,921
Six months ended June 30, 2002	58,230	64,858	(34,558)	5,883	(1,225)		93,188
Segment assets:							
At June 30, 2003	437,808	2,127,386	164,336		18,100	93,341	2,840,971
At December 31, 2002	444,016	2,166,524	134,237		16,825	49,237	2,810,839
Investments in and advances to unconsolidated affiliates:							
At June 30, 2003	96,213	207,651	33,000	48,467			385,331
At December 31, 2002	95,467	213,632	33,000	54,894			396,993
Intangible Assets:							
At June 30, 2003	69,811	7,779	192,893				270,483
At December 31, 2002	71,069	7,895	198,697				277,661
Goodwill:							
At June 30, 2003 and December 31, 2002	81,547						81,547

Our revenues are derived from a wide customer base. All consolidated revenues during the three and six months ended June 30, 2003 and 2002 were earned in the United States. The increase in period-to-period revenues is primarily due to acquisitions and higher NGL, propylene and natural gas prices, both of which offset the effects of lower volumes at many of our pipelines and facilities.

For the three months ended June 30, 2003 and 2002, total segment gross operating margin was $106.5 million and $66.9 million, respectively. For the six month periods ended June 30, 2003 and 2002, total segment gross operating margin was $232.9 million and $93.2 million, respectively. The primary reasons for the increase in total segment gross operating margin between the periods are (a) 2003 includes gross operating margin from Mid-America and Seminole (acquired in July 2002) and (b) 2002 includes significant commodity hedging losses (see Note 11). Mid-America and Seminole's gross operating margin is classified under our Pipelines segment while commodity hedging results are primarily a function of our Processing segment activities.

13. UNIT OPTION PLAN ACCOUNTING

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the "1998 Plan"). Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our Limited Partner's Common Units (the "Units") may be granted to EPCO's key employees who perform management, administrative or operational functions for us. The exercise price per Unit, vesting and expiration terms, and rights to receive distributions on Units granted are determined by EPCO for each grant. EPCO purchases the Units under the 1998 Plan at fair value either in the open market or from our Limited Partner (in the form of newly-issued Common Units). In general, our responsibility for reimbursing EPCO for the expense it incurs when these options are exercised is as follows:

- We pay EPCO for the costs attributable to equity-based awards granted to operations personnel it employs on our behalf.
- We pay EPCO for the costs attributable to equity-based awards granted to administrative and management personnel it hires in response to our expansion and business activities.
- We pay EPCO for our share of the costs attributable to equity-based awards granted to certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 who manage our business and affairs. These costs are reimbursed through the administrative service fees we pay EPCO. EPCO is responsible for the actual costs of such awards when these options are exercised.

We account for our share of the cost of these awards using the intrinsic value-based method in accordance with APB No. 25, "Accounting for Stock Issued to Employees." The exercise price of each option granted is equivalent to or greater than the market price of the Unit at the date of grant. Accordingly, no compensation expense related to Unit option grants is recognized in our Statements of Consolidated Operations and Comprehensive Income.

Accounting principles require us to illustrate the pro forma effect on our net income as if the fair value-based method of accounting (based on SFAS No. 123, "Accounting for Stock Based Compensation") had been applied to the 1998 Plan. The following table shows these pro forma effects for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Historical net income	$ 33,577	$ 22,447	$ 74,926	$ 5,296
Additional Unit option-based compensation expense estimated using the fair value-based method	(171)	(273)	(342)	(546)
Pro forma net income	$ 33,406	$ 22,174	$ 74,584	$ 4,750

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

For the three and six months ended June 30, 2003 and 2002.

Enterprise Products Partners L.P. is a publicly-traded limited partnership (NYSE, symbol "EPD") that conducts substantially all of its business through its 98.9899% owned subsidiary, *Enterprise Products Operating L.P.* (the "Operating Partnership"), the Operating Partnership's subsidiaries, and a number of investments with industry partners. Since the Operating Partnership owns substantially all of Enterprise Products Partners L.P.'s consolidated assets and conducts substantially all of its business and operations, the information set forth herein constitutes combined information for the two registrants. Unless the context requires otherwise, references to "we", "us", "our" or the "Company" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P., which includes Enterprise Products Operating L.P. and its subsidiaries.

The following discussion and analysis should be read in conjunction with the unaudited consolidated financial statements and notes thereto of the Company and Operating Partnership included under Part I of this quarterly report on Form 10-Q. Additionally, certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this report.

Our results of operations

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization and propylene fractionation. Processing includes our natural gas processing business and related NGL marketing activities. Octane Enhancement represents our equity interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income.

We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. 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 intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. 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, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For additional information regarding our business segments, see footnote 12 of our Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report on Form 10-Q.

The following table summarizes our consolidated revenues, costs and expenses, equity in income (loss) of unconsolidated affiliates and operating income for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues	$1,210,659	$ 786,257	$2,692,245	$ 1,448,311
Operating costs and expenses	1,134,030	745,655	2,520,734	1,410,207
Selling, general and administrative costs	10,053	7,740	21,524	15,702
Equity in income (loss) of unconsolidated affiliates	(228)	7,068	1,393	16,295
Operating income	66,348	39,930	151,380	38,697

The following table reconciles consolidated operating income to our measurement of total segment gross operating margin for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Operating income	$ 66,348	$ 39,930	$ 151,380	$ 38,697
Adjustments to reconcile operating income to total segment gross operating margin:				
Depreciation and amortization in operating costs and expenses	27,844	16,963	55,502	34,199
Retained lease expense, net in operating costs and expenses	2,274	2,273	4,547	4,578
Loss (gain) on sale of assets in operating costs and expenses	(36)	(2)	(32)	12
Selling, general and administrative costs	10,053	7,740	21,524	15,702
Total segment gross operating margin	$ 106,483	$ 66,904	$ 232,921	$ 93,188

EPCO subleases certain equipment to us located at our Mont Belvieu facility and 100 railroad tankcars for $1 dollar per year. These subleases (the “retained leases”) are part of the EPCO Agreement we executed with EPCO at our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. Operating costs and expenses (as shown in the Statements of Consolidated Operations and Comprehensive Income) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. 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. In addition, EPCO has assigned to us the purchase options associated with these leases. For additional information regarding the EPCO Agreement and the retained leases, see "*Related party transactions*" on page 54 and "*Capital spending*" on page 53 of this quarterly report.

Our gross operating margin amounts by segment were as follows for the periods indicated (dollars in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Gross operating margin by segment:				
Pipelines	$ 71,969	$ 32,190	$ 143,901	$ 64,858
Fractionation	35,871	33,853	64,918	58,230
Processing	2,685	(1,182)	32,641	(34,558)
Octane enhancement	(3,228)	2,877	(6,669)	5,883
Other	(814)	(834)	(1,870)	(1,225)
Total segment gross operating margin	$ 106,483	$ 66,904	$ 232,921	$ 93,188

Our significant pipeline throughput and plant production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
MBPD, net				
NGL and petrochemical pipelines	1,295	499	1,332	518
NGL fractionation	201	237	218	226
Propylene fractionation	58	58	59	55
Isomerization	82	86	81	80
Equity NGL production	47	74	51	78
Octane enhancement	3	6	3	5
BBtus per day, net				
Natural gas pipelines	1,033	1,300	1,033	1,262
Equivalent MBPD, net				
NGL, petrochemical and natural gas pipelines	1,567	841	1,604	850

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2002:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(a)	(b)	(a)	(a)	(a)	(a)	(a)	(a)
2002								
1st Quarter	$ 2.34	$ 21.41	$ 0.22	$ 0.30	$ 0.38	$ 0.44	$ 0.16	$ 0.12
2nd Quarter	$ 3.38	$ 26.26	$ 0.26	$ 0.40	$ 0.48	$ 0.51	$ 0.20	$ 0.17
3rd Quarter	$ 3.16	$ 28.30	$ 0.26	$ 0.42	$ 0.52	$ 0.58	$ 0.21	$ 0.16
4th Quarter	$ 3.99	$ 28.33	$ 0.31	$ 0.49	$ 0.60	$ 0.63	$ 0.20	$ 0.15
Average	$ 3.22	$ 26.08	$ 0.26	$ 0.40	$ 0.50	$ 0.54	$ 0.20	$ 0.15
2003								
1st Quarter	$ 6.58	$ 34.07	$ 0.43	$ 0.65	$ 0.76	$ 0.80	$ 0.24	$ 0.21
2nd Quarter	$ 5.40	$ 29.02	$ 0.39	$ 0.53	$ 0.58	$ 0.62	$ 0.25	$ 0.19
Average	$ 5.99	$ 31.55	$ 0.41	$ 0.59	$ 0.67	$ 0.71	$ 0.25	$ 0.20

(a) *Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI.*
(b) *Crude Oil price is representative of the index price for West Texas Intermediate.*

Three months ended June 30, 2003 compared to three months ended June 30, 2002

Revenues, costs and expenses and operating income and total segment gross operating margin.

Revenues for the three months ended June 30, 2003 increased $424.4 million over those recorded during the same period in 2002. Costs and expenses for the second quarter of 2003 increased $390.7 million over those of the second quarter of 2002. The increase in revenues and costs and expenses is primarily due to acquisitions and higher NGL, propylene and natural gas prices quarter-to-quarter, both of which offset the effects of lower volumes at many of our pipelines and facilities. Since the second quarter of 2002, we have completed several business acquisitions, the most significant of which was our $1.2 billion purchase of indirect interests in the Mid-America and Seminole pipeline systems in July 2002.

In general, higher NGL, propylene and natural gas prices result in increased revenues from our various marketing activities; however, these same higher prices also increase our cost of sales within those activities as feedstock and other purchase prices rise. In addition, higher natural gas prices during the second quarter of 2003 increased energy-related costs for many of our businesses when compared to the second quarter of 2002.

The combination of a decrease in demand for NGLs by the petrochemical industry, high natural gas prices relative to NGL prices and higher energy-related operating costs had the effect of lowering NGL extraction rates at most domestic gas processing facilities, which reduced NGL volumes available for downstream pipeline transportation and NGL fractionation. The majority of the operating margin earned by our natural gas processing facilities is based on the relative economic value of the mixed NGLs extracted by the gas plants compared to the costs of extracting the mixed NGLs (principally that of natural gas as a feedstock and as a fuel, plus plant operating expenses). The most significant determinant of the relative economic value of NGLs is demand by the petrochemical industry for use in manufacturing plastics and other chemicals. When compared to 2002, this industry has been operating at lower utilization rates during 2003 primarily due to a recession in the domestic manufacturing sector. As a result of the higher relative cost of NGLs, which are a function of higher natural gas prices, the petrochemical industry has been utilizing more crude-based alternatives such as naphtha and gas oil instead of NGLs. The resulting weak demand for NGLs by the petrochemical industry has reduced the value of NGLs to natural gas processors (by limiting NGL prices), which led to reduced NGL extraction rates during the 2003 period.

The increase in operating costs and expenses during the 2003 period was partially offset by $5.8 million in commodity hedging losses included in results for the second quarter of 2002, which were not repeated during the second quarter of 2003. Equity in income of unconsolidated affiliates decreased $7.3 million quarter-to-quarter primarily due to operating losses incurred by our BEF investment.

As a result of the items noted in the previous paragraphs, operating income for the second quarter of 2003 increased $26.4 million over that of the second quarter of 2002. Total segment gross operating margin increased $39.6 million quarter-to-quarter due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin. On a quarter-to-quarter basis, depreciation and amortization costs increased $10.9 million and selling, general and administrative costs increased $2.3 million primarily due to acquisitions and other business expansion activities.

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

Pipelines. Gross operating margin from our Pipelines segment was $72.0 million for the second quarter of 2003 compared to $32.2 million for the second quarter of 2002. On an energy-equivalent basis where 3.8 MMBtus of natural gas throughput are equivalent to one barrel of NGL throughput, net pipeline throughput was 1,567 MBPD during the second quarter of 2003 versus 841 MBPD during the same period in 2002. The increase in gross operating margin and throughput volume is primarily due to our acquisition of Mid-America and Seminole in July 2002. These two systems earned gross operating margin of $39.9 million on net volumes of 759 MBPD during the second quarter of 2003. Net pipeline transportation volumes on the Mid-America and Seminole systems were 11% lower than their historical volumes for the second quarter of 2002 generally due to lower NGL extraction rates at gas processing facilities served by these pipelines.

Excluding the contributions of Mid-America and Seminole, gross operating margin for the Pipelines segment was $32.1 million for the second quarter of 2003 versus $32.2 million for the same period in 2002. On an energy-equivalent basis (excluding these two pipeline systems), net pipeline throughput decreased to 808 MBPD during the 2003 period from 841 MBPD during the 2002 period. Higher margins and volumes from our NGL import terminal (and related HSC pipeline), Lou-Tex Propylene and Lou-Tex NGL pipelines nearly offset the effects of lower margins and volumes from our other Pipelines' segment operations, due in part to lower NGL extraction rates at regional gas processing facilities and demand for NGLs by industry.

Fractionation. Gross operating margin from our Fractionation segment was $35.9 million for the second quarter of 2003 compared to $33.9 million for the second quarter of 2002. Gross operating margin from NGL fractionation improved $4.2 million quarter-to-quarter. Net NGL fractionation volumes decreased to 201 MBPD during the second quarter of 2003 from 237 MBPD during the same period in 2002. The increase in NGL fractionation gross operating margin is primarily due to $6.8 million in net gains associated with the measurement of mixed NGLs in storage pending fractionation at our Mont Belvieu facility, which more than offset an overall decline in margins at our NGL fractionation facilities caused by lower fractionation volumes and reduced demand for NGLs by industry. The decrease in fractionation volumes is primarily due to lower NGL extraction rates at gas processing facilities.

Gross operating margin from propylene fractionation declined $3.7 million quarter-to-quarter primarily due to lower petrochemical marketing margins resulting from higher feedstock costs. Net propylene fractionation volumes were 58 MBPD for both quarterly periods.

Gross operating margin from isomerization increased $2.0 million quarter-to-quarter. Isomerization volumes decreased to 82 MBPD during the second quarter of 2003 from 86 MBPD during the second quarter of 2002. The increase in gross operating margin from isomerization is generally attributable to higher isomerization fees, which were partially offset by higher energy-related operating costs. Certain components of our isomerization fees are indexed to the price of natural gas, which was significantly higher during the second quarter of 2003 relative to the same period in 2002. The increase in isomerization fees more than offset the effect of lower isomerization volumes and higher operating costs.

Processing. Gross operating margin from our Processing segment was $2.7 million for the second quarter of 2003 compared to a loss of $1.2 million for the second quarter of 2002. The second quarter of 2002 includes $5.8 million in commodity hedging losses, the underlying strategies of which were discontinued in 2002. Our commodity hedging results for the second quarter of 2003 were negligible. Equity NGL production at our gas processing plants for the second quarter of 2003 was 47 MBPD versus 74 MBPD during the second quarter of 2002. The decrease in equity NGL production quarter-to-quarter is largely attributable to reduced demand for NGLs by industry and higher natural gas prices relative to NGL prices, which caused most natural gas processors to minimize the amount of NGLs extracted at their facilities.

Octane enhancement. Our equity earnings from BEF were a loss of $3.2 million for the second quarter of 2003 compared to income of $2.9 million for the second quarter of 2002. Net MTBE production from this facility decreased to 3 MBPD during the second quarter of 2003 versus 6 MBPD during the same period in 2002. MTBE sales margins were generally insufficient to cover operating expenses during the second quarter of 2003. The deterioration in margins is primarily due to reduced MTBE demand and high feedstock costs. The decrease in MTBE demand is attributable to certain states beginning to phase-out their MTBE use. In response to these low margins, the BEF facility was shutdown for the month of June 2003 for economic reasons (the facility restarted production in mid-July). For additional information regarding BEF's MTBE facility, see "*Other items*" on page 58.

Selling, general and administrative costs. These expenses were $10.1 million for the second quarter of 2003 versus $7.7 million for the same period in 2002. The increase is primarily due to additional staff and resources required to support expanded business activities resulting from acquisitions and other business development.

Interest expense. Interest expense increased to $33.3 million during the second quarter of 2003 from $19.0 million during the second quarter of 2002. The increase is primarily due to additional debt we incurred as a result of business acquisitions since the end of June 2002. Our weighted-average debt principal outstanding was $2.0 billion during the second quarter of 2003 compared to $1.2 billion during the second quarter of 2002.

Six months ended June 30, 2003 compared to six months ended June 30, 2002

Revenues, costs and expenses, operating income and total segment gross operating margin.

Revenues for the six months ended June 30, 2003 increased $1.2 billion over those recorded during the same period in 2002. Year-to-date costs and expenses for 2003 increased $1.1 billion over those of the first half of 2002. As with the quarter-to-quarter variances noted previously, the increase in year-to-date revenues and costs and expenses between the two six month periods is primarily due to acquisitions and higher NGL, propylene and natural gas prices, both of which offset the effects of lower volumes at many of our pipelines and facilities. In addition, costs and expenses for the six months ended June 30, 2002 includes a $50.9 million loss related to commodity

hedging activities, which was not repeated during the 2003 period. Equity in income of unconsolidated affiliates decreased $14.9 million period-to-period primarily due to operating losses incurred by our BEF investment.

As a result of the items noted in the previous paragraph, operating income for the first six months of 2003 increased $112.7 million over that of the first half of 2002. Total segment gross operating margin increased $139.7 million period-to-period due to the same general reasons underlying the increase in operating income. On a period-to-period basis, depreciation and amortization charges increased $21.3 million and selling, general and administrative costs increased $5.8 million primarily due to acquisitions and other business expansion activities.

The following information highlights the significant variances in gross operating margin by business segment between the six months ended June 30, 2003 and the same period in 2002:

Pipelines. Gross operating margin from our Pipelines segment was $143.9 million for the first six months of 2003 compared to $64.9 million for the same period during 2002. On an energy-equivalent basis, net pipeline throughput was 1,604 MBPD during the first half of 2003 versus 850 MBPD during the first half of 2002. The increase in gross operating margin and throughput volume is primarily due to our acquisition of Mid-America and Seminole. These two systems earned gross operating margin of $87.4 million on net volumes of 787 MBPD during the first six months of 2003. Net pipeline transportation volumes on the Mid-America and Seminole systems were 6% lower than their historical volumes for the first half of 2002 generally due to lower NGL extraction rates at gas processing facilities served by these pipelines.

Excluding the contributions of Mid-America and Seminole, gross operating margin for the Pipelines segment was $56.5 million for the first six months of 2003 versus $64.9 million for the same period in 2002. On an energy-equivalent basis (excluding these two pipeline systems), net pipeline throughput decreased to 817 MBPD during the 2003 period from 850 MBPD during the 2002 period. Higher margins and volumes from our NGL import terminal (and related HSC pipeline), Lou-Tex Propylene and Lou-Tex NGL pipelines were offset by the effect of lower margins and volumes from our other Pipelines' segment operations, due in part to lower NGL extraction rates at regional gas processing facilities and demand for NGLs by industry. In addition, 2003 gross operating margin from our NGL and petrochemical storage operations was $5.0 million lower period-to-period as a result of net charges associated with the measurement of liquids volumes held in storage.

Fractionation. Gross operating margin from our Fractionation segment was $64.9 million for the first six months of 2003 compared to $58.2 million for the same period in 2002. Gross operating margin from NGL fractionation improved $6.4 million period-to-period. Net NGL fractionation volumes decreased to 218 MBPD during the first half of 2003 from 226 MBPD during the same period in 2002. The increase in NGL fractionation gross operating margin is primarily due to (i) mixed NGL measurement gains we recognized during the second quarter of 2003 at our Mont Belvieu facility and (ii) higher in-kind fees at Norco during the 2003 period attributable to the general increase in NGL prices, both of which more than offset an overall decline in margins at our NGL fractionation facilities caused by lower fractionation volumes. The decrease in NGL fractionation volumes is primarily due to lower NGL extraction rates at gas processing facilities and reduced demand for NGLs by industry.

Gross operating margin from propylene fractionation declined $6.5 million period-to-period primarily due to lower petrochemical marketing margins resulting from higher feedstock and energy-related costs. Net propylene fractionation volumes were 59 MBPD for the first six months of 2003 compared to 55 MBPD for the same period during 2002.

Gross operating margin from isomerization increased $5.5 million period-to-period. Isomerization volumes increased to 81 MBPD during the first six months of 2003 from 80 MBPD during the first six months of 2002. The increase in gross operating margin from isomerization is generally attributable to higher isomerization fees and by-product revenues, which were partially offset by higher energy-related operating costs. Certain components of our isomerization fees are indexed to the price of natural gas, which was significantly higher during the first six months of 2003 relative to the same period in 2002.

Processing. Gross operating margin from our Processing segment was $32.6 million for the first six months of 2003 compared to a loss of $34.6 million for the same period in 2002. The first half of 2002 includes $50.9 million in commodity hedging losses, the underlying strategies of which were discontinued in 2002. Our commodity hedging

results for the first half of 2003 were a loss of $0.9 million. Equity NGL production at our gas processing plants during the first six months of 2003 was 51 MBPD compared to 78 MBPD during the first six months of 2002.

The decrease in equity NGL production period-to-period is largely attributable to reduced demand for NGLs by industry and higher natural gas prices relative to NGL prices, which caused most natural gas processors to minimize the amount of NGLs extracted at their facilities. In order to meet the natural gas processing needs of Shell (our largest natural gas processing customer) in this challenging business environment, we renegotiated certain aspects of the 20-year Shell natural gas processing agreement during the first quarter of 2003. For a general discussion of this amendment, see “*Related party transactions*” on page 54.

Octane enhancement. Our equity earnings from BEF were a loss of $6.7 million for the first six months of 2003 compared to income of $5.9 million for the same period during 2002. Net MTBE production from this facility decreased to 3 MBPD during the first half of 2003 versus 5 MBPD during the same period in 2002. The decrease in equity earnings from BEF is attributable to increased downtime during 2003 for maintenance and economic reasons and a general deterioration in MTBE margins. The deterioration in MTBE margins is primarily due to reduced MTBE demand and high feedstock costs. The decrease in MTBE demand is attributable to certain states beginning to phase-out their use of MTBE in gasoline. For additional information regarding BEF’s MTBE facility, see “*Other items*” on page 58.

Selling, general and administrative costs. These expenses were $21.5 million for the first six months of 2003 versus $15.7 million for the first six months of 2002. The increase is primarily due to additional staff and resources required to support expanded business activities resulting from acquisitions and other business development. The 2003 period includes a $2.0 million payment we made to Williams for general and administrative transition services related to our acquisition of the Mid-America and Seminole pipelines. These payments ceased in February 2003 when we began operating these two systems.

Interest expense. Interest expense increased to $75.2 million for the first six months of 2003 from $37.6 million for the same period in 2002. The increase is primarily due to additional debt we incurred as a result of business acquisitions since the end of June 2002. Our weighted-average debt principal outstanding was $2.0 billion during the first six months of 2003 compared to $1.2 billion during the first six months of 2002.

Interest expense for 2003 includes $11.3 million of loan cost amortization related to the 364-Day Term Loan, which was fully repaid in February 2003. For additional information regarding our debt obligations and changes therein since December 31, 2002, please see “*Our liquidity and capital resources – Our debt obligations*” beginning on page 51.

Outlook for remainder of 2003

Our outlook for the remainder of 2003 is largely dependent on demand for NGLs by the petrochemical industry and an overall recovery in the domestic manufacturing sector; improved natural gas processing economics both in the Rocky Mountains and along the Gulf Coast and new natural gas production from deepwater Gulf of Mexico developments. We are encouraged by the modest improvement in business conditions that we have seen in the early stages of the third quarter of 2003.

According to industry publications, petrochemical demand for various NGL products in July 2003 has increased from the lows of June 2003. In addition, natural gas processing economics have moderately improved along the Gulf Coast leading us to increase NGL extraction rates at our natural gas processing facilities above those of the second quarter of 2003. Many of the gas processing plants in the Rocky Mountains remain on a day-to-day basis for maximizing NGL extraction rates, particularly that of ethane. In terms of new natural gas production from deepwater developments in the Gulf of Mexico, we expect to see a modest increase in our equity NGL production over the balance of 2003 as the Princess, Medusa and Habanero natural gas developments begin production.

Our liquidity and capital resources

The following represents a combined discussion of our liquidity and capital resources and those of our Operating Partnership. Within this section, references to partnership equity pertains to limited partner interests issued by us, whereas references to debt pertains to those obligations entered into by our Operating Partnership or its subsidiaries.

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures (both sustaining and expansion-related), 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. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources including (either separately or in combination) cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional partnership equity and public or private placement debt. 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.

Operating cash flows primarily reflect the effects of net income adjusted for depreciation and amortization, equity income and cash distributions from unconsolidated affiliates, fluctuations in the fair value of financial instruments and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks. The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential, agricultural and commercial heating. Reduced demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products, increased competition from petroleum-based products due to pricing differences or other reasons, could have a negative impact on our earnings and thus the availability of cash from operating activities. Other risks include fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For a more complete discussion of these and other risk factors pertinent to our businesses, see "*Cautionary Statement regarding Forward-Looking Information and Risk Factors*" on page 59 of this quarterly report.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At June 30, 2003, we had approximately $1.9 billion in principal outstanding under various debt agreements. On that date, total borrowing capacity under our revolving commercial bank credit facilities was $500 million of which $368.5 million of capacity was available. For additional information regarding our debt, see "*Our debt obligations*" beginning on page 51.

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of up to $500 million of partnership equity or public debt obligations. In October 2002, we sold 9,800,000 Common Units under this shelf registration statement which generated $182.5 million of cash to us (including related capital contributions from our General Partner). In January 2003, we sold an additional 14,662,500 Common Units under this shelf registration which generated $258.2 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by these equity offerings to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. Also, in January and February 2003, we issued Senior Notes C ($350 million principal amount) and Senior Notes D ($500 million principal amount). For information regarding our application of cash generated by these debt offerings, please read the section titled "*Our debt obligations*" within this "*Our liquidity and capital resources*" discussion.

In January 2003, we filed a new $1.5 billion universal shelf registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In accordance with Rule 457(p) promulgated under the Securities Act of 1933, as amended, the registration fee associated with the unsold portion of the securities under the shelf registration statement filed in February 2001 was used to offset the registration fee due in connection with

our $1.5 billion universal shelf registration statement. When our new shelf registration was declared effective by the SEC in April 2003, the securities remaining under the shelf registration statement filed in February 2001 were deemed deregistered.

In June 2003, we sold 11,960,000 Common Units under the January 2003 shelf registration statement, which generated $261.2 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by this equity offering to reduce debt outstanding under our revolving credit facilities. As a result of meeting certain financial tests, the Subordination Period (as defined within our partnership agreement) ended on August 1, 2003. With the expiration of the Subordination Period, we may prudently issue an unlimited number of Units for general partnership purposes.

In July 2003, we filed a registration statement with the SEC regarding our Distribution Reinvestment Plan (the "Plan"), which was declared effective by the SEC on July 16, 2003. The Plan 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 in the purchase of additional Common Units. The registration statement covers the issuance of up to 5,000,000 Common Units under the Plan. A complete description of the Plan is included in our Form S-3 filed with the SEC on July 16, 2003.

Initial reinvestments under the Plan will occur in August 2003 for those Common Unitholders of record and beneficial owners on July 31, 2003 who elect to participate with regards to our declared distribution payable on August 11, 2003. As a result of any reinvestment proceeds, our General Partner will be required to make cash contributions to us and our Operating Partnership in order to maintain its ownership interests. We expect to use the cash generated from this reinvestment program for general partnership purposes.

If deemed necessary, we believe that additional financing arrangements can be obtained on reasonable terms. Furthermore, we believe that maintenance of our investment grade credit ratings combined with a 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.

Six months ended June 30, 2003 compared to six months ended June 30, 2002

The following discussion highlights significant period-to-period comparisons regarding our consolidated operating, investing and financing activities cash flows:

Operating activities cash flows. Cash flow from operating activities was an inflow of $133.0 million during the first six months of 2003 compared to an inflow of $45.2 million during the first six months of 2002. The following table summarizes the major components of operating activities cash flows for first six months of 2003 and 2002 (dollars in thousands):

	For the Six Months Ended June 30,	
	2003	**2002**
Net income	$ 73,610	$ 5,117
Adjustments to reconcile net income to cash flows provided by (used for) operating activities before changes in operating accounts:		
Depreciation and amortization	67,466	35,349
Equity in income of unconsolidated affiliates	(1,393)	(16,295)
Distributions received from unconsolidated affiliates	20,865	29,113
Changes in fair market value of financial instruments	(23)	19,702
Other	13,575	4,576
Cash flow from operating activities before net effect of changes in operating accounts	174,100	77,562
Net effect of changes in operating accounts	(41,067)	(32,379)
Operating activities cash flows	$ 133,033	$ 45,183

As shown in the table above, cash flow before the net effect of changes in operating accounts was an inflow of $174.1 million during the first six months of 2003 versus $77.6 million during the same period in 2002. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments. The $96.5 million increase in this element of our cash flows is primarily due to:

- earnings from acquired businesses present in the 2003 period but not in the 2002 period (particularly those of Mid-America and Seminole which we acquired in July 2002);
- the 2002 period including $50.9 million of commodity hedging losses versus $0.9 million of such losses during the 2003 period; offset by,
- higher interest costs associated with debt we incurred and issued since the first quarter of 2002 to finance acquisitions.

The $32.1 million increase in depreciation and amortization is primarily due to businesses we acquired since the first quarter of 2002. The net effect of changes in operating accounts are generally the result of timing of cash receipts from sales and cash payments for inventory, purchases and other expenses near the end of each period. For additional information regarding changes in operating accounts, please see footnote 10 in our Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Investing activities cash flows. During the first six months of 2003, we used $112.1 million in cash for investing activities compared to $431.7 million during the same period in 2002. We used $32.7 million and $394.8 million for business acquisitions during the first six months of 2003 and 2002, respectively. The 2003 period includes our acquisition of the Port Neches Pipeline and the remaining 50% ownership interest in EPIK. The 2002 period includes our acquisition of Diamond-Koch's Mont Belvieu NGL and petrochemical storage business and propylene fractionation business.

Our capital expenditures were $54.5 million during the first six months of 2003 and $26.8 million during the first six months of 2002. The $27.7 million increase in capital expenditures is primarily due to expansions of our Norco NGL fractionator and Neptune gas processing facility. In addition, we made investments in and advances to our unconsolidated affiliates of $25.1 million during the first six months of 2003 compared to $10.1 million during the first six months of 2002. This increase is primarily due to funding our share of the expansion projects of our Gulf of Mexico natural gas pipeline investments.

Financing activities cash flows. Our financing activities were a cash outflow of $15.7 million during the first six months of 2003 versus a cash inflow of $257.3 million during the first six months of 2002. During the 2003 period, we made net payments on our debt obligations of $371.8 million primarily resulting from the use of proceeds from our January and June equity offerings. The 2003 period reflects our issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount) and the final repayment of $1.0 billion that was outstanding under our 364-Day Term Loan. The 2002 period reflects borrowings under our revolving bank credit facilities to fund the $239 million acquisition of Diamond-Koch's propylene fractionation business and various working capital needs.

Proceeds from our January and June 2003 equity offerings totaled $514.3 million, which includes our General Partner's related $5.1 million contribution to us. Our General Partner also contributed $5.2 million to our Operating Partnership in connection with these offerings. Distributions to our partners and minority interests increased to $148.3 million during the first six months of 2003 from $100.0 million during the first six months of 2002. The $44.0 million increase in distributions to partners is primarily due to increases in both the declared quarterly distribution rates and the number of Units eligible for distributions.

Our debt obligations

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

	June 30, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003		$ 1,022,000
364-Day Revolving Credit facility, variable rate, due November 2004		99,000
Multi-Year Revolving Credit facility, variable rate, due November 2005	$ 130,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	45,000
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	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	1,879,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,652	1,774
Less unamortized discount on:		
Senior Notes A	(62)	(81)
Senior Notes B	(215)	(230)
Senior Notes D	(5,768)	
Less current maturities of debt	(15,000)	(15,000)
Long-term debt	$ 1,859,607	$ 2,231,463

Letters of credit. At June 30, 2003 and December 31, 2002, we had $75 million of standby letter of credit capacity under our Multi-Year Revolving Credit facility. We had $1.5 million of letters of credit outstanding under this facility at June 30, 2003 and $2.4 million outstanding at December 31, 2002.

Covenants. We were in compliance with the various covenants of our debt agreements at June 30, 2003 and December 31, 2002.

Parent-Subsidiary guarantor relationships. We act as guarantor of all of our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 78.4% of its ownership interests). If the Operating Partnership were to default on any of its debt we guarantee, we would be responsible for full payment of that obligation.

New senior notes issued during first quarter of 2003

During the first quarter of 2003, we completed the issuance of $850 million of long-term senior notes (Senior Notes C and D). Senior Notes C and D are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. We guarantee both Senior Notes C and D for our subsidiary through an unsecured and unsubordinated guarantee that is non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right if we elect to call the debt prior to its scheduled maturity. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes C. In January 2003, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 1, 2013 (“Senior Notes C”), from which we received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, we exchanged 100% of the private placement Senior Notes C for publicly-registered Senior Notes C.

Senior Notes D. In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 1, 2033 (“Senior Notes D”), from which we received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit facility. The remaining proceeds were used for working capital purposes. In July 2003, we exchanged 100% of the private placement Senior Notes D for publicly-registered Senior Notes D.

Repayment of 364-Day Term Loan

In July 2002, our Operating Partnership entered into the $1.2 billion senior unsecured 364-Day Term Loan to initially fund the acquisition of indirect interests in Mid-America and Seminole. We used $178.5 million of the $182.5 million in proceeds from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.2 million in proceeds from the January 2003 equity offering, $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our issuance of Senior Notes D to completely repay the 364-Day Term Loan by February 2003.

Revolving credit facilities

We used $60.0 million in proceeds from the issuance of Senior Notes D in February 2003 to reduce the balance outstanding under our 364-Day Revolving Credit facility. In addition, we applied $261.2 million of the net proceeds from our June 2003 equity offering to reduce the balances then outstanding under our revolving credit facilities, of which $102 million was applied against the 364-Day Revolving Credit facility and $159.2 million against the Multi-Year Revolving Credit facility.

At June 30, 2003, we had $230 million of stand-alone borrowing capacity available under our 364-Day Revolving Credit facility, with no principal balance outstanding. In addition, we had $270 million in stand-alone borrowing capacity available under our Multi-Year Revolving Credit facility at June 30, 2003. We had $130 million of principal and $1.5 million in letters of credit outstanding under this facility at that date, with $138.5 million of unused capacity.

The credit line available under our 364-Day Revolving Credit facility expires in November 2003. In accordance with the terms of the credit agreement of this facility, we have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004). Management expects to refinance this facility in the fourth quarter of 2003.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations for the six months ended June 30, 2003:

	Range of interest rates paid	**Weighted- average interest rate paid**
364-Day Term Loan (a)	2.59% - 2.88%	2.85%
364-Day Revolving Credit facility	2.43% - 4.25%	2.52%
Multi-Year Revolving Credit facility	1.69% - 4.25%	1.96%

(a) This facility was repaid in February 2003.

Credit ratings

Our current investment grade credit ratings are Baa2 by Moody’s Investor Service and BBB by Standard and Poors. Both agencies have affirmed that the outlook for our ratings is stable. We believe that the maintenance of an investment grade credit rating is important in managing our liquidity and capital resource requirements. We maintain regular communications with these ratings agencies which independently judge our creditworthiness based on a variety of quantitative and qualitative factors.

Capital spending

At June 30, 2003, we had $6.7 million in estimated outstanding purchase commitments attributable to capital projects. Of this amount, $6.5 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.2 million is associated with our share of the capital projects of unconsolidated affiliates which will be recorded as additional investments in these companies.

During the remainder of 2003, we expect capital spending on internal growth projects to approximate $84.7 million, of which $35.2 million is forecasted for various projects within our Pipelines segment; $26.8 million for the expansion of our Norco NGL fractionator and $8.7 million for the expansion of our Neptune gas processing facility. Our unconsolidated affiliates forecast a combined $38.3 million in capital expenditures for the remainder of 2003, the majority of which relate to expansion projects on our Gulf of Mexico natural gas pipeline systems. Our share of these forecasted capital expenditures is estimated at $14.1 million.

EPCO subleases to us all of the equipment it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, two cogeneration units and approximately 100 railcars for one dollar per year and has assigned to us its purchase option under such leases (the “retained leases”). EPCO remains liable for the lease payments associated with these items. We have notified the original lessor of the isomerization unit of our intent to exercise the purchase option assigned to us. The purchase price of this equipment is expected to be up to $23.1 million and be payable in 2004.

Material contractual obligations

There have been no significant changes in our material contractual obligations outside the ordinary course of business since December 31, 2002 except for the following:

- In February 2003, we completely repaid the $1.0 billion principal balance that was outstanding under the 364-Day Term Loan at December 31, 2002 using proceeds from debt and equity offerings we completed during the first quarter of 2003 (which included the issuance of our Senior Notes C and D discussed below).
- We issued our $350 million in principal amount Senior Notes C in January 2003. These notes mature in 2013.
- We issued our $500 million in principal amount Senior Notes D in February 2003. These notes mature in 2033.
- We used $60 million in proceeds from the issuance of Senior Notes D to repay a portion of indebtedness then outstanding under our 364-Day Revolving Credit facility.
- We used $261.2 million in proceeds and contributions related to our June 2003 equity offering to reduce indebtedness outstanding under our 364-Day Revolving Credit and Multi-Year Revolving Credit facilities.

The following table summarizes our updated material contractual obligations related to debt:

Contractual Obligations	Total	2003	2004 through 2005	2006 through 2007	After 2007
Principal payments to be made under debt obligations	$ 1,879,000	$ 15,000	$ 510,000		$ 1,354,000

Related party transactions

Relationship with EPCO and Its Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers of the General Partner are employees of EPCO. The principal business activity of our General Partner is to act as our managing partner. Collectively, EPCO and its affiliates owned 55.4% of our limited partnership interests and 70.0% of our General Partner at June 30, 2003.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO. We reimburse EPCO for the costs of its employees who perform operating functions for us. In addition, we reimburse EPCO for the costs of certain of employees who manage our business and affairs.

EPCO is the operator of certain facilities we own or have an equity interest in. We also have entered into an agreement with EPCO to provide trucking services for us pertaining to the loading and transportation of products. Lastly, in the normal course of business, we buy from and sell NGL products to EPCO’s Canadian affiliate. The following table shows our related party revenues and operating expenses attributable to EPCO for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues from consolidated operations	$ 996	$ 161	$ 1,559	$ 2,460

Operating costs and expenses	27,940	20,059	74,145	39,988
Selling, general and administrative expenses	6,957	5,835	13,341	11,788

Relationship with Shell

We have a commercial relationship with Shell as a partner, customer and vendor. At June 30, 2003, Shell owned approximately 19.1% of our limited partnership interests and 30.0% of our General Partner. Currently, three members of the Board of Directors of our General Partner (J.A. Berget, J.R. Eagan and A.Y. Noojin, III) are employees of Shell.

Shell and its affiliates are the Company's single largest customer. During the six months ended June 30, 2003 and 2002, they accounted for 6.0% and 9.8%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to them and the fees we charge them for pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from them.

The most significant contract affecting our natural gas processing business is the 20-year keepwhole Shell processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. The Shell processing agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019. This contract was amended effective March 1, 2003. In general, the amended contract includes the following rights and obligations:

- the exclusive right, but not the obligation in all cases, to process substantially all of Shell's Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation in all cases, to process all natural gas production from leases dedicated by Shell for the life of such leases; plus
- the right to all title, interest and ownership in the mixed NGL stream extracted by our gas processing plants from Shell's natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after any mixed NGLs are extracted.

As part of our natural gas processing obligations under this contract, we reimburse Shell for the energy value of (i) the NGLs we extract from the natural gas stream and (ii) the natural gas we remove from the stream and consume as fuel. This energy value is referred to as plant thermal reduction ("PTR") and is based on the energy content of the natural gas taken out of the stream (measured in Btus). The amended contract contains a mechanism (termed "Consideration Adjustment Outside of Normal Operations" or "CAONO") to adjust the value of the PTR we reimburse to Shell. The CAONO, in effect, protects us from processing Shell's natural gas at an economic loss when the value of the NGLs we extract is less than the sum of the cost of the PTR reimbursement, operating costs of the gas processing facility and other costs such as NGL fractionation and pipeline fees.

In general, the CAONO adjustment requires the comparison of our average net gas processing margin to an upper and lower limit (all as defined within the agreement). If our average net processing margin is below the lower limit, the PTR reimbursement payable to Shell is decreased by the product of the absolute value of the difference between our average net processing margin and the specified lower limit multiplied by the volume of NGLs extracted. To the extent our average net processing margin is higher than the upper limit, the PTR reimbursement payable to Shell is increased by the product of the difference between the average net gas processing margin and the specified upper limit multiplied by the volume of NGLs extracted. The underlying purpose of the CAONO mechanism is to provide Shell with relative assurance that its gas will continue to be processed during periods when natural gas prices are high relative to NGL prices (times when we would normally choose not to process a producer's natural gas stream) while continuing to protect us from processing Shell's gas at an economic loss.

The following table shows our related party revenues and operating expenses attributable to Shell for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues from consolidated operations	$ 79,216	$ 64,701	$ 161,436	$ 122,358
Operating costs and expenses	141,227	134,441	312,941	239,589

Shell is also a partner with us in the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. We also lease from Shell its 45.4% interest in our Splitter I propylene fractionation facility.

Recent accounting developments

SFAS No. 143, "Accounting for Asset Retirement Obligations." We adopted this standard as of January 1, 2003. This statement establishes accounting standards for the recognition and measurement of an asset retirement obligation ("ARO") liability and the associated asset retirement cost. Our adoption of this standard had no material impact on our financial statements. For a discussion regarding our implementation of this new standard, see footnote 5 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting literature to clarify its meaning, applicability and to make various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 146, "*Accounting for Costs Associated with Exit and Disposal Activities.*" We adopted this standard as of January 1, 2003. This statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of an entity's commitment to an exit or disposal plan. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure.*" We adopted this standard as of December 31, 2002. This statement provides alternative methods of transition from a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148

amends the disclosure requirements of SFAS No. 123 in both annual and interim financial statements. We have provided the information required by this statement under footnote 13 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report. Apart from this additional footnote disclosure, our adoption of this standard has had no material impact on our financial statements.

SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities.*" This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. This statement is effective for contracts entered into or modified after June 20, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. We are currently evaluating the effect that SFAS No. 149 will have on our financial statements.

SFAS No. 150, "*Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*." This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. The effective date of this standard for us was July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, "*Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others*." We implemented this FASB interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation on page 51 within our discussion of debt obligations.

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 as of January 31, 2003 has had no material effect on our financial statements.

Our 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.

There have been no significant changes in our critical accounting policies since December 31, 2002. For a detailed discussion of these policies, please see the section titled "*Our critical accounting policies*" under Item 7 of our annual report on Form 10-K/A for 2002. The following is a condensed discussion of our critical accounting policies and the estimates and assumptions underlying them.

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. We use the straight-line method to depreciate our property, plant and equipment. Our estimate of an asset's useful life is based on a number of assumptions including technological changes that may affect the asset's usefulness and the manner in which we intend to physically use the asset. If we subsequently change our assumptions regarding these factors, it would result in an increase or decrease in depreciation expense. Additionally, if we determine that an asset's undepreciated cost may not be recoverable due to impairment, this would result in a charge against earnings.

At June 30, 2003 and December 31, 2002, the net book value of our property, plant and equipment was $2.8 billion. See footnote 5 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our property, plant and equipment.

Amortization methods and estimated useful lives of qualifying intangible assets

Our recorded intangible assets primarily consist of the estimated value assigned to certain contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life. Our estimate of useful life is based on a number of factors including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors. If our underlying assumptions regarding the useful life of an intangible asset change, we then might need to adjust the amortization period of such asset which would increase or decrease amortization expense. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment, this would result in a charge against earnings.

At June 30, 2003 and December 31, 2002, the carrying value of our intangible asset portfolio was $270.5 million and $277.7 million. See footnote 7 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our intangible assets.

Methods we employ to measure the fair value of goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level annually, and more frequently, if circumstances warrant. This testing involves calculating the fair value of a reporting unit, which in turn is based on our assumptions regarding the future economic prospects of the reporting unit. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could impact the fair value of the reporting unit and result in a charge to earnings to reduce the carrying value of goodwill.

At June 30, 2003 and December 31, 2002, the carrying value of our goodwill was $81.5 million. See footnote 7 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our goodwill.

Our revenue recognition polices

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we use will not prove to be significantly different from actual amounts due to the routine nature of these estimates and the stability of our operations.

Mark-to-market accounting for certain financial instruments

Our earnings are also affected by use of the mark-to-market method of accounting for certain financial instruments. We use short-term, highly liquid financial instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our Processing segment. The use of mark-to-market accounting for financial instruments may cause our non-cash earnings to fluctuate based upon changes in underlying indexes, primarily those related to commodity prices. Fair value for the financial instruments we employ is determined using price data from highly liquid markets such as the NYMEX commodity exchange.

During the first six months of 2002, we recognized a loss of $50.9 million from our commodity hedging activities. Of this loss, $19.0 million was attributable to the change in fair value of the portfolio between December 31, 2001 and June 30, 2002. The fair value of open positions at June 30, 2002 was a payable of $11.1 million. In March 2002, the

effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices; therefore, the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During the first six months of 2003, we utilized a limited number of commodity financial instruments from which we recorded a loss of $0.9 million. The fair value of open positions at June 30, 2003 was a payable of approximately $2 thousand. See footnote 11 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our financial instruments.

Other items

Uncertainties regarding our investment in BEF

We own a 33.3% interest in BEF, which owns a facility that currently produces MTBE, a motor gasoline additive that enhances octane and is used in reformulated gasoline. At June 30, 2003, the carrying value of our equity investment in BEF was $48.5 million.

BEF's facility has advantages over several of its competitors. It is fully integrated into our Mont Belvieu complex, which supplies all of BEF's isobutane requirements. This integration also results in lower operational and administrative expenses as personnel are shared between our various Mont Belvieu operations. BEF's variable operating costs are generally lower than many of its peers since BEF recovers several by-products created in the manufacture of MTBE (hydrogen, mixed butanes and propane/propylene mix). In addition, BEF's facility is based on a more efficient design (the Oleflex process) than many of its older competitors.

The production of MTBE is primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. In recent years, MTBE has been detected in municipal and private water supplies (generally the result of leaking gasoline tanks) resulting in various legal actions. BEF has not been named in any MTBE legal action to date.

As a result of such environmental concerns, several states have enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. According to U.S. Energy Information Administration statistics, seventeen states had passed such restrictions on MTBE as of April 2003. Of these states, eleven had passed various forms of MTBE bans. California, the largest consumer of MTBE during 2002 at 31.7% of domestic consumption, has banned MTBE effective January 1, 2004. New York and Connecticut have also enacted similar bans on MTBE that would take effect on January 1, 2004. Together, New York and Connecticut represented 10.6% of domestic consumption during 2002. Based on 2002 consumption data, the remaining eight states with MTBE bans utilize minimal amounts of the oxygenate for their motor gasoline requirements.

In light of these continuing developments, we and the other two owners of BEF are actively compiling a feasibility study to convert the plant to an alternative purpose. At present, we believe the most likely use of the facility will be for the production of alkylate. We expect that this high-octane additive will be needed in greater quantities by the motor gasoline industry to offset the loss of MTBE’s octane content in gasoline and the deficiencies of ethanol use in gasoline.

The cost to convert the facility will depend on the manufacturing process employed and the level of production desired by the partnership. These costs could be significant in relation to our current investment in BEF. Several key components of the BEF facility can be utilized in the manufacture of alkylate; thus, our conversion costs are expected to be significantly lower than those of a third party attempting to build a completely new facility. We believe that operating margins from alkylate production will provide an attractive return on our BEF investment.

If a decision is made by the partnership to convert the facility to alkylate production, we anticipate that it would take approximately two and a half years before alkylate production would begin. During this transition period, BEF would continue to produce MTBE as market conditions warrant.

Conversion of EPCO Subordinated Units to Common Units

On May 1, 2003, 10,704,936 of EPCO’s Subordinated Units converted to Common Units as a result of our satisfying certain financial tests. The remaining 21,409,872 Subordinated Units converted to Common Units on August 1, 2003. These conversions have no impact upon our earnings per unit or distributions since Subordinated Units are already included in both the basic and fully-diluted earnings per unit calculations and are distribution-bearing.

Conversion of Shell Special Units to Common Units

On August 1, 2003, the last 10,000,000 of Shell’s non-distribution bearing Special Units converted to Common Units. The conversion will have an impact on basic earnings per Unit beginning with the third quarter of 2003. These units were already included in our fully-diluted earnings per Unit computations. Since Common Units are distribution-bearing, our limited partner cash distributions to Shell will increase beginning with the distribution we expect to make in the fourth quarter of 2003.

Cautionary Statement regarding Forward-Looking Information and Risk Factors

This quarterly report 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. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review our summarized “*Risk Factors*” below.

Risk Factors

Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

- A decrease in the difference between NGL product prices and natural gas prices results in lower margins on volumes processed, which would adversely affect our profitability.
- A reduction in demand for our products by the petrochemical, refining or heating industries could adversely affect our results of operations.
- A decline in the volume of NGLs delivered to our facilities could adversely affect our results of operations.
- Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.
- Acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.
- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our Unitholders and our ability to make payments on our debt securities.
- We have leverage that may restrict our future financial and operating flexibility.
- Terrorist attacks aimed at our facilities could adversely affect our business.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions, primarily within our Processing segment. In general, the types of risks we attempt to hedge are those relating to variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

There has been no material change in our commodity financial instruments portfolio since December 31, 2002. During the first quarter of 2003, we settled all interest rate-related financial instruments that were outstanding at December 31, 2002 (see the following discussion titled "*Interest rate-related financial instruments portfolio*"). For additional information regarding our financial instruments, see footnote 11 of our Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Commodity financial instruments portfolio

At December 31, 2002, the net fair value of this portfolio was a payable of $26 thousand, based entirely upon quoted market prices. At June 30, 2003, the net fair value of this portfolio was a payable of $2 thousand. We continue to have only a limited number of commodity financial instruments outstanding. The sensitivity of the fair value of our commodity financial instruments portfolio at June 30, 2003 to a hypothetical 10% movement in the underlying quoted market prices is negligible.

During the first six months of 2002, we recognized a loss of $50.9 million from our Processing segment's commodity hedging activities that was recorded as an operating cost in our Statements of Consolidated Operations and Comprehensive Income. In March 2002, the effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices; therefore, the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During the first six months of 2003, we recorded a loss of $0.9 million from our commodity hedging activities, of which $0.8 million is attributable to commodity hedging activities within the Pipelines segment and the remainder to those within the Processing segment.

Interest rate-related financial instruments portfolio

Interest rate swap agreements. At December 31, 2002, we had one interest rate swap outstanding having a notional amount of $54 million and a fair value at that date of $1.6 million. The counterparty elected to exercise its option to terminate this swap as of March 1, 2003 and we received $1.6 million associated with the final settlement of this swap on that date. The early termination of the swap had no impact on our earnings. At June 30, 2003, we have no interest rate swap agreements outstanding.

Treasury Locks. During the fourth quarter of 2002, we entered into seven treasury lock transactions, each with an original maturity of either January 31, 2003 or April 15, 2003. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific U.S. treasury security for an established period of time. The purpose of these financial instruments was to hedge the underlying treasury interest rate associated with our anticipated issuance of debt in early 2003 to partially refinance the Mid-America and Seminole acquisitions. Our treasury lock transactions are accounted for as cash flow hedges under SFAS No. 133. The notional amounts of the treasury lock transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

We elected to settle all of the treasury locks during the first quarter of 2003 in connection with our issuance of Senior Notes C and D (see "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Our liquidity and capital resources—Our debt obligations*" under Item 2 of this quarterly report). The settlement of the treasury locks resulted in our receipt of $5.4 million in cash.

The fair value of these instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The $3.6 million net liability was recorded as a component of comprehensive income on that date, with no impact on 2002 net income. As a result of settlement of the treasury locks, the $3.6 million net liability was reclassified out of accumulated other comprehensive income in Partners' Equity to offset the current asset and liabilities we recorded at December 31, 2002, with no impact on 2003 net income. For additional information regarding our treasury lock transactions, see our footnote 11 of our Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Item 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, the CEO and CFO of the General Partner of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively the "registrants") have evaluated the effectiveness of the registrants' disclosure controls and procedures, including internal control over financial reporting. These disclosure controls and procedures are those controls and other procedures we maintain, which are designed to provide reasonable assurance that all of the information required to be disclosed by the registrants in all of their combined and separate periodic reports filed with the SEC is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by the registrants in their reports filed or submitted under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including the CEO and CFO of the General Partner, as appropriate to allow those persons to make timely decisions regarding required disclosure.

In the course of their evaluation of the registrants' disclosure controls and procedures, the CEO and CFO noted no significant deficiencies or material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrants' ability to record, process, summarize and report financial information. In addition, no fraud, whether or not material, was detected involving management or other employees who have a significant role in the registrants' internal control over financial reporting. In addition, there has not been any change in the registrants' disclosure controls and procedures during the quarter that has materially affected, or is reasonably likely to materially affect, the registrants' internal control over financial reporting. Since no significant deficiencies or material weaknesses were detected in the registrants' disclosure controls and procedures, no corrective actions regarding these controls and procedures are currently warranted.

PART II. OTHER INFORMATION.
Item 6. EXHIBITS AND REPORTS ON FORM 8-K.

(a) Exhibits.

Exhibit No.	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).
3.1	First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to Form 8-K/A-l filed October 27, 1999).
3.2	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 19, 2002 (incorporated by reference to Exhibit 3.2 to Form 10-K filed March 31, 2003).
3.3	Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.4	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated August 7, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.5	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 17, 2002 (incorporated by reference to Exhibit 3.5 to Form 8-K filed December 17, 2002).
3.6	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (incorporated by reference to Exhibit 3.2 to Registration Statement on Form S-1/A filed July 21, 1998).
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 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 A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	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).
4.5	Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

4.6	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).
4.7	Rule 144A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.8	Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 10-K filed March 31, 2003).
4.9	Form of 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).
4.10	Registration Rights Agreement dated as of February 14, 2003, by and among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.10 to Form 10-K filed March 31, 2003).
4.11	Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12	Global Note representing $400 million principal amount of 7.50% Senior Notes due 2011. Global Note representing $50 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).
4.13	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).
4.14	$250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15	$150 Million 364-Day Revolving Credit Facility November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 24, 2001).
4.16	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.17	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $150 Million 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.5 to Form 8-K filed January 24, 2001).
4.18	First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.19	Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).
4.20	Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.21	Fourth Amendment to Multi-Year Revolving Credit Facility dated effective as of November 15, 2002 (incorporated by reference to Exhibit 4.19 to Form 10-Q filed November 13, 2002).
4.22	First Amendment to 364-Day Credit Facility dated November 6, 2001, effective as of November 16, 2001 (incorporated by reference to Exhibit 4.13 to Form 10-Q filed August 13, 2002).
4.23	Second Amendment to 364-Day Revolving Credit Facility dated April 24, 2002 (incorporated by reference to Exhibit 4.15 to Form 10-Q filed May 14, 2002).
4.24	Third Amendment to 364-Day Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.2 to Form 8-K filed August 12, 2002).

4.25	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.26	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.27	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
10.1**	Sixth Amendment to Conveyance of Gas Processing Rights, dated as of March 1, 2003 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company, Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 9, 2003).
10.2	Letter agreement dated April 9, 2003, relating to Sixth Amendment to Conveyance of Gas Processing Rights related to Exhibit 10.1 to this report (incorporated by reference to Exhibit 10.2 to Form 8-K filed May 9, 2003).
31.1#	Sarbanes-Oxley Section 302 certification of O.S. Andras for Enterprise Products Partners L.P. for the June 30, 2003 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of O.S. Andras for Enterprise Products Operating L.P. for the June 30, 2003 quarterly report on Form 10-Q.
31.3#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2003 quarterly report on Form 10-Q.
31.4#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Operating L.P. for the June 30, 2003 quarterly report on Form 10-Q.
32.1#	Sarbanes-Oxley Section 1350 certification of O.S. Andras for the June 30, 2003 quarterly report on Form 10-Q.
32.2#	Sarbanes-Oxley Section 1350 certification of Michael A. Creel for the June 30, 2003 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 and the Commission file number for Enterprise Products Operating L.P. is 333-93239-01.

** Portions of this Exhibit have been omitted pursuant to a request for confidential treatment.

\# Filed with this report.

(b) Reports on Form 8-K.

April 30, 2003 filing, Items 9 and 12. On April 30, 2003, we issued a press release regarding our financial results for the three months ended March 31, 2003 and 2002. A copy of the earnings press release was furnished as an exhibit.

May 9, 2003 filing, Item 5. (1) We refiled various historical audited and unaudited financial statements of Mid-America and Seminole so that they would be incorporated by reference into recently filed registration statements. (2) We filed updated pro forma financial information for fiscal 2002 reflecting various acquisitions and capital transactions. (3) We filed contractual information relating to an amendment of the Shell Processing Agreement.

June 2, 2003 filing, Item 5. On May 29, 2003, we entered into an underwriting agreement related to our June 2003 equity offering. A copy of the underwriting agreement was filed as an exhibit to this current report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this combined quarterly report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on August 13, 2003.

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

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

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P.

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Operating L.P., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Operating L.P.;

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ O.S. Andras

Name: O.S. Andras
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

EXHIBIT 31.3

SARBANES-OXLEY SECTION 302 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

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

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

EXHIBIT 31.4

SARBANES-OXLEY SECTION 302 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P.

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Operating L.P., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Operating L.P.;

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF O.S. ANDRAS, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P. AND ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this combined quarterly report of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively, the “Registrants”) on Form 10-Q for the quarterly period ending June 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, O.S. Andras, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrants, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

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

/s/ O.S. Andras

Name: O.S. Andras
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Operating L.P. and
Enterprise Products Partners L.P.

Date: August 13, 2003

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

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P. AND ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this combined quarterly report of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively, the "Registrants") on Form 10-Q for the quarterly period ending June 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrants, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

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

/s/ Michael A. Creel

Name:	Michael A. Creel
Title:	Chief Financial Officer of Enterprise Products GP, LLC on behalf of Enterprise Products Operating L.P. and Enterprise Products Partners L.P.
Date:	August 13, 2003

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

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

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

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ O.S. Andras

Name: O.S. Andras
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC