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

FORM 10-Q

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

For the quarterly period ended September 30, 2002

[ ] 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)

Registrant's 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 [ ]

Limited Partner interests (e.g. Common Units) of Enterprise Products Partners L.P. trade on the New York Stock Exchange under symbol "EPD". As of November 13, 2002, 141,694,766 Common Units were outstanding (excluding those Common Units held in treasury). Enterprise Products Operating L.P. is owned 98.9899% by Enterprise Products Partners L.P. and 1.0101% by the General Partner of both registrants, Enterprise Products GP, LLC. No common equity securities of Enterprise Products Operating L.P. are publicly traded.

EXPLANATORY NOTE

This report constitutes a combined report 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
BBtu	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
BP	BP PLC and affiliates
BPD	Barrels per day
BRF	Baton Rouge Fractionators LLC, an equity investment of EPOLP
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment of EPOLP
Burlington	Burlington Resources Inc. and affiliates
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronTexaco	ChevronTexaco Corp., its subsidiaries and affiliates
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
ConocoPhillips	ConocoPhillips Petroleum Company and affiliates
CPG	Cents per gallon
Diamond-Koch	Refers to affiliates of Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity investment of EPOLP
Duke	Duke Energy Corporation and its affiliates
E-Oaktree	E-Oaktree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
EBITDA	Earnings before interest, taxes, depreciation and amortization
EPCO	Enterprise Products Company, 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
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
EPU	Earnings per Unit
Equistar	A joint venture of Lyondell Chemical Company, Millenium Chemicals, Inc. and Occidental Petroleum Corporation
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment of EPOLP
FASB	Financial Accounting Standards Board
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles of the United States of America
General Partner	Enterprise Products GP, LLC, the general partner of the Company and the Operating Partnership
HSC	Denotes our Houston Ship Channel pipeline system
IPO	Refers to our initial public offering in July 1998
Kinder Morgan	Kinder Morgan Operating LP "A"
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment of EPOLP
LIBOR	London interbank offering rate
Mapletree	Mapletree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
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

Glossary (continued)

Mid-America	Mid-America Pipeline Company, LLC
MMcf/d	Million cubic feet per day
MMBtu/d	Million British thermal units per day, a measure of heating value
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
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)
NYSE	New York Stock Exchange
Ocean Breeze	Ocean Breeze Pipeline Company, LLC, an equity investment of EPOLP (merged into Neptune during fourth quarter of 2001)
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
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
S and P	Standard and Poor's Rating Services
Starfish	Starfish Pipeline Company LLC, an equity investment of EPOLP
TNGL acquisition	Refers to the acquisition of Tejas Natural Gas Liquids, LLC, an affiliate of

	Shell, in 1999
Tri-States	Tri-States NGL Pipeline LLC, an equity investment of EPOLP
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

Enterprise Products Partners L.P.
Consolidated Balance Sheets
(Dollars in thousands)

ASSETS	September 30, 2002 (unaudited)	December 31, 2001
Current Assets		
Cash and cash equivalents (includes restricted cash of $7,273 at September 30, 2002 and $5,752 at December 31, 2001)	$ 61,976	$ 137,823
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,039 at September 30, 2002 and $20,642 at December 31, 2001	322,441	256,927
Accounts receivable - affiliates	319	4,375
Inventories	227,058	62,942
Prepaid and other current assets	46,221	50,207
Total current assets	658,015	512,274
Property, Plant and Equipment, Net	2,823,249	1,306,790
Investments in and Advances to Unconsolidated Affiliates	401,088	398,201
Intangible assets, net of accumulated amortization of $21,955 at September 30, 2002 and $13,084 at December 31, 2001	281,279	202,226
Goodwill	81,547	
Other Assets	9,776	5,201
Total	$4,254,954	$2,424,692
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$1,215,000	
Accounts payable - trade	85,972	$54,269
Accounts payable - affiliates	52,380	29,885
Accrued gas payables	397,442	227,035
Accrued expenses	24,766	22,460
Accrued interest	15,491	24,302
Other current liabilities	45,025	44,764
Total current liabilities	1,836,076	402,715
Long-Term Debt	1,313,507	855,278
Other Long-Term Liabilities	8,020	8,061
Minority Interest	67,142	11,716
Commitments and Contingencies		
Partners' Equity		
Common Units (131,894,766 Units outstanding at September 30, 2002 and 102,721,830 at December 31, 2001)	731,876	651,872
Subordinated Units (32,114,804 Units outstanding at September 30, 2002 and 42,819,740 at December 31, 2001)	161,735	193,107
Special Units (10,000,000 Units outstanding at September 30, 2002 and 29,000,000 Units at December 31, 2001)	143,926	296,634
Treasury Units, at cost (859,200 Common Units outstanding at September 30, 2002 and 327,200 at December 31, 2001)	(17,808)	(6,222)
General Partner	10,480	11,531
Total Partners' Equity	1,030,209	1,146,922
Total	$4,254,954	$2,424,692

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Operations
(Dollars in thousands, except per Unit amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
REVENUES				
Revenues from consolidated operations	$943,313	$723,329	$2,391,624	$2,519,041
Equity income in unconsolidated affiliates	5,963	6,289	22,258	17,350
Total	949,276	729,618	2,413,882	2,536,391
COST AND EXPENSES				
Operating costs and expenses	868,631	634,496	2,278,675	2,263,876

Selling, general and administrative	12,289	7,716	27,991	21,621
Total	880,920	642,212	2,306,666	2,285,497
OPERATING INCOME	68,356	87,406	107,216	250,894
OTHER INCOME (EXPENSE)				
Interest expense	(30,690)	(12,610)	(68,235)	(35,928)
Interest income from unconsolidated affiliates	28		120	31
Dividend income from unconsolidated affiliates		392	2,196	2,024
Interest income - other	434	861	2,009	6,338
Other, net	74	(275)	43	(806)
Other income (expense)	(30,154)	(11,632)	(63,867)	(28,341)
INCOME BEFORE PROVISION FOR TAXES AND MINORITY INTEREST	38,202	75,774	43,349	222,553
PROVISION FOR TAXES	(2,056)		(2,056)	
INCOME BEFORE MINORITY INTEREST	36,146	75,774	41,293	222,553
MINORITY INTEREST	(1,296)	(767)	(1,326)	(2,245)
NET INCOME	$ 34,850	$ 75,007	$ 39,967	$ 220,308
ALLOCATION OF NET INCOME TO:				
Limited partners	$ 32,076	$ 73,408	$ 33,299	$ 216,339
General partner	$ 2,774	$ 1,599	$ 6,668	$ 3,969
BASIC EARNINGS PER UNIT				
Income before minority interest	$ 0.21	$ 0.53	$ 0.23	$ 1.59
Net income per Common and Subordinated unit	$ 0.20	$ 0.52	$ 0.22	$ 1.58
DILUTED EARNINGS PER UNIT				
Income before minority interest	$ 0.19	$ 0.43	$ 0.20	$ 1.29
Net income per Common, Subordinated and Special unit	$ 0.18	$ 0.43	$ 0.19	$ 1.28

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Cash Flows
(Dollars in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2002	2001
OPERATING ACTIVITIES		
Net income	$ 39,967	$220,308
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization	62,907	37,245
Equity in income of unconsolidated affiliates	(22,258)	(17,350)
Distributions received from unconsolidated affiliates	40,114	30,602
Leases paid by EPCO	6,782	7,900
Minority interest	1,326	2,245
Loss (gain) on sale of assets	6	(392)
Deferred income tax expense	529	
Changes in fair market value of financial instruments	12,830	(39,430)
Net effect of changes in operating accounts	27,906	(116,362)
Operating activities cash flows	170,109	124,766
INVESTING ACTIVITIES		
Capital expenditures	(46,958)	(92,641)
Proceeds from sale of assets	18	567
Business acquisitions, net of cash received	(1,615,298)	(225,665)
Acquisition of intangible asset	(2,000)	
Investments in and advances to unconsolidated affiliates	(13,193)	(119,865)
Investing activities cash flows	(1,677,431)	(437,604)
FINANCING ACTIVITIES		
Long-term debt borrowings	1,883,000	449,717
Long-term debt repayments	(270,000)	
Debt issuance costs	(16,522)	(3,125)
Cash dividends paid to partners	(150,674)	(117,125)
Cash dividends paid to minority interest by Operating Partnership	(1,650)	(1,203)
Cash contributions from minority interest	109	80
Treasury Units purchased	(12,788)	(8,839)
Increase in restricted cash associated with commodity hedging activities	(1,521)	(9,032)
Financing activities cash flows	1,429,954	310,473

NET CHANGE IN CASH AND CASH EQUIVALENTS	(77,368)	(2,365)
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	60,409
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 54,703	$ 58,044

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 September 30, 2002 and consolidated results of operations and cash flows for the three and nine months ended September 30, 2002 and 2001. 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 report on Form 10-Q. We own 98.9899% of the Operating Partnership and act as guarantor of certain debt obligations of the Operating Partnership. 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 generally accepted accounting principles 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 (File No. 1-14323) for the year ended December 31, 2001.

The results of operations for the three and nine months ended September 30, 2002 are not necessarily indicative of the results to be expected for the full year.

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

Certain abbreviated entity names and other capitalized terms are described 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.

Two-for-one split of Limited Partner Units

On February 27, 2002, the General Partner approved a two-for-one split for each class of our partnership Units. The partnership Unit split was accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document reflect the Unit split, unless otherwise indicated.

Provision for taxes

As a result of our acquisition of Seminole on July 31, 2002 (see Note 2), we now recognize income tax expense related to this entity's operations. Our provision for taxes is computed using the liability method and is provided on all temporary differences between the financial basis and the tax basis of Seminole's assets and liabilities.

2. BUSINESS ACQUISITIONS

Acquisition of Mid-America and Seminole in July 2002

On July 31, 2002, we acquired equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America," formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole"). The purchase price of the acquisitions was approximately $1.2 billion (subject to certain post-closing purchase price adjustments).

The acquisition of Mid-America and Seminole significantly enhances our existing asset base by:

|X| accessing NGL-rich natural gas production in major North American natural gas producing regions;
|X| expanding our integrated natural gas and NGL network;
|X| providing access to new end markets for NGL products; and
|X| increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The combination of these assets with our existing assets also creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States, and provides additional access to new end markets for NGL products.

The acquisitions include a 98% ownership interest in Mapletree, LLC, which is the sole owner of Mid-America and certain propane terminals and storage facilities. Mid-America owns a major NGL pipeline system consisting of three NGL pipelines, with 7,226 miles of pipeline. Mid-America's 2,548-mile Rocky Mountain system transports mixed NGLs from the Rocky Mountain Overthrust and San Juan basin areas to the Hobbs hub located on the Texas-New Mexico border. Its 2,740-mile Conway North segment links the large NGL hub at Conway, Kansas to the upper Midwest; its 1,938-mile Conway South system connects the Conway hub with Kansas refineries and transports mixed NGLs from Conway, Kansas to the Hobbs hub. We also acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole. The Seminole pipeline consists of a 1,281-mile pipeline which transports mixed NGLs and NGL products from the Hobbs hub and the Permian basin to Mont Belvieu, Texas.

The funding of these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"; see Note 8 for a description of this debt). Our plans for permanent financing of these acquisitions include the issuance of equity and debt in amounts which are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet. The post-closing purchase price adjustments are expected to be completed during the fourth quarter of 2002. These acquisitions did not require any material governmental approvals.

Acquisition of Diamond-Koch propylene fractionation business in February 2002

In February 2002, we purchased various propylene fractionation assets and certain inventories of refinery grade propylene, propane, and polymer grade propylene from Diamond-Koch. These include a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas (the "Splitter III" facility), a 50% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas, and varying interests in several supporting distribution pipelines and related equipment. Splitter III has the capacity to produce approximately 41 MBPD of polymer grade propylene. These assets are part of our Mont Belvieu propylene fractionation operations, which is part of the Fractionation segment. The purchase price of $239.0 million was funded by a drawdown on our Multi-Year and 364-Day Revolving Credit facilities (see Note 8).

Acquisition of Diamond-Koch storage business in January 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facilities consist of 30 salt dome storage caverns with a useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities

provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene, polymer grade propylene, chemical grade propylene and refinery grade propylene).

The facilities are located in Mont Belvieu, Texas and serve the largest petrochemical and refinery complex in the United States. Collectively, these facilities represent the largest underground storage operation of its kind in the world. The size and location of the business provide it with a competitive position to increase its services to expanding Gulf Coast petrochemical complexes. These assets are part of our Mont Belvieu storage operations, which is part of the Pipelines segment. The purchase price of $129.6 million was funded by utilizing cash on hand.

Other minor acquisitions completed during 2002

We completed the purchase of an additional interest in our Mont Belvieu NGL fractionator from ChevronTexaco and the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources during the second quarter of 2002. Due to the immaterial nature of these two transactions, our discussion of each is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. In September 2002, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. ChevronTexaco was required to sell its 12.5% interest in a consent order by the FTC as a condition of approving the merger between Chevron and Texaco. The effective date of the purchase was June 1, 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. Effective June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant. The transaction was finalized in September 2002 with the expiration of certain preferential purchase rights to the facility held by third-parties.

Acadian Gas post-closing adjustments completed in April 2002

In April 2002, we finalized the post-closing purchase price adjustment associated with our April 2001 acquisition of Acadian Gas. Acadian Gas was acquired from an affiliate of Shell and is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. As a result, we paid Shell $18.0 million for various working capital items, of which the majority were related to natural gas inventories.

Allocation of amounts paid during 2002

The acquisitions and post-closing adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	D-K Storage	D-K Propylene Fractionation	Mid-America and Seminole	Other	Total
Accounts and notes receivable			$ 11,777		$ 11,777
Accounts receivable - affiliates			7,799		7,799
Inventories		$ 4,994	14,376		19,370
Prepaids and other current assets	$890	3,148	8,445		12,483
Property, plant and equipment	120,571	96,772	1,284,337	$19,043	1,520,723
Investments in unconsolidated affiliates		7,550			7,550
Intangible assets	8,127	53,000		31,137	92,264
Goodwill		73,691			73,691
Other assets			2,396		2,396
Accounts payable - affiliates			(7,799)		(7,799)
Accrued expenses			(5,733)	(2,457)	(8,190)
Accrued interest			(667)		(667)
Other current liabilities		(107)	(11,254)	10,993	(368)
Long-term debt			(60,000)		(60,000)
Other long-term liabilities			(90)		(90)
Minority interest			(55,641)		(55,641)
Total purchase price	$129,588	$239,048	$1,187,946	$58,716	$1,615,298

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The fair value estimates for the D-K storage; D-K propylene fractionation; Mid-America and Seminole; and Toca-Western acquisitions were developed by independent appraisers using recognized business valuation techniques. The allocation of the D-K storage purchase price is preliminary pending the results of a repermitting process expected to be complete during the fourth quarter of 2002. Also, the Mid-America and Seminole allocations are preliminary pending completion of a final review of these businesses which is expected to be completed during the first quarter of 2003. The purchase price allocations related to the Acadian Gas post-closing adjustment and the acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator are based on previously issued fair value reports.

The purchase price paid for the propylene fractionation business resulted in $73.7 million in goodwill. The goodwill primarily represents the value management has attached to future earnings improvements and to the strategic location of the assets. Earnings from the propylene business are expected to improve substantially from the last few years with the years 2003 and 2004 projected to be peak years in the petrochemical business cycle.

The propylene fractionation assets are located in Mont Belvieu, Texas on the Gulf Coast, the largest natural gas liquids and petrochemical marketplace in the U.S. The assets have access to substantial supply from major Gulf Coast and central U.S. producers of refinery grade propylene. The polymer grade products produced at the facility have competitive advantages because of distribution direct to customers via affiliated pipelines and through an affiliated export facility.

Combined pro forma effect of Mid-America, Seminole, Diamond-Koch and Acadian Gas business acquisitions

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the following acquired businesses:

|X| D-K storage (acquired January 1, 2002) and propylene fractionation (acquired February 1, 2002);
|X| Mid-America and Seminole (both acquired July 31, 2002); and
|X| Acadian Gas (acquired April 1, 2001).

Our historical Statements of Consolidated Operations reflect the operations of each acquired business since their respective acquisition dates.

The following pro forma information have been prepared as if the acquisitions had been completed on January 1 of the respective periods presented as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available to and certain estimates and assumptions made by management and, as a result, are not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
PRO FORMA EARNINGS DATA				
Revenues	$988,512	$870,448	$2,595,587	$3,196,252
Operating income	82,667	113,634	186,973	315,907
Net income	$ 42,583	$ 77,950	$ 74,529	$ 220,442
Income before minority interest	$ 44,418	$ 80,008	$ 79,227	$ 225,774
Less: General partner interest	(2,851)	(1,628)	(7,014)	(3,971)
Net income before minority interest available to Limited Partners	41,567	79,380	72,213	221,803
Less: Minority interest	(1,835)	(2,059)	(4,698)	(5,332)
Net income available to Limited Partners	$ 39,732	$ 76,321	$ 67,515	$ 216,471
PRO FORMA BASIC EARNINGS PER UNIT				
Numerator:				
Net income before minority interest available to Limited Partners	$ 41,567	$ 78,380	$ 72,213	$ 221,803
Net income available to Limited Partners	$ 39,732	$ 76,321	$ 67,515	$ 216,471
Denominator, weighted-average Units outstanding	157,617	141,814	149,519	135,334
Pro forma basic earnings per Unit:				
Net income before minority interest available to Limited Partners	$0.26	$0.55	$ 0.48	$ 1.64
Net income available to Limited Partners	$0.25	$0.54	$ 0.45	$ 1.60
PRO FORMA DILUTED EARNINGS PER UNIT				
Numerator:				
Net income before minority interest available to Limited Partners	$ 41,567	$ 78,380	$ 72,213	$ 221,803
Net income available to Limited Partners	$ 39,732	$ 76,321	$ 67,515	$ 216,471
Denominator, weighted-average Units outstanding	174,019	172,206	174,274	169,638
Pro forma basic earnings per Unit:				
Net income before minority interest available to Limited Partners	$ 0.24	$ 0.46	$ 0.41	$ 1.31
Net income available to Limited Partners	$ 0.23	$ 0.44	$ 0.39	$ 1.28

Pro forma net income for each period includes (among other pro forma adjustments) the impact of interest expense associated with the $1.2 billion 364-Day Term Loan related to the Mid-America and Seminole acquisitions. The pro forma earnings data assume that the entire $1.2 billion 364-Day Term Loan is outstanding during all periods presented. To the extent that we refinance the Mid-America and Seminole acquisitions using equity offerings, interest expense will be reduced as the proceeds from such offerings are applied against outstanding debt. In October 2002, we completed an equity offering of 9.8 million Common Units which generated proceeds of approximately $180 million after expenses (see Note 14 for a description of this subsequent event). The proceeds from this offering were used to partially repay debt. Neither pro forma interest expense nor earnings per Unit reflect the impact of the October 2002 equity offering.

Total pro forma interest expense for the three months ending September 30, 2002 and 2001 was $35.8 million and $31.5 million, respectively. Included in these amounts is the effect of the one-year amortization of the debt issuance costs we incurred to secure the 364-Day Term Loan ($1.2 million in pro forma amortization expense for the 2002 period and $3.8 million for the 2001 period). Additionally, the pro forma interest expense adjustment directly attributable to the 364-Day Term Loan was $3.2 million for the third quarter of 2002 and $9.6 million for the third quarter of 2001. Our historical results for the third quarter of 2002 already include the effects of the 364-Day Term Loan for two months (August and September).

Total pro forma interest expense for the nine months ending September 30, 2002 and 2001 was $103.0 million and $91.1 million, respectively. The pro forma adjustment relating to the amortization of the debt issuance costs was $8.8 million for the 2002 period and $11.3 million for the 2001 period. The pro forma interest expense adjustment directly attributable to the 364-Day Term Loan was $22.4 million for the 2002 period and $28.8 million for the 2001 period.

3. INVENTORIES

Our inventories were as follows at the dates indicated:

	September 30, 2002	December 31, 2001
Working inventory	$153,802	$29,393
Forward-sales inventory	51,732	33,549
Peak Season inventory	21,524	
Inventory	$227,058	$62,942

A description of each inventory is as follows:

- Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemicals that are available for sale. This inventory is valued at the lower of average cost or market, with "market" being determined by spot-market related prices.
- The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with "market" being defined as the weighted-average of the sales prices of the forward sales contracts.
- The peak season inventory is comprised of segregated NGL volumes that are expected to be sold outside of the current summer-winter season and is valued at the lower of average cost or market, with "market" being determined by spot-market related prices. These volumes are generally expected to be sold within the next twelve months, but may be held for longer periods depending on market conditions.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost 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 and generally affect our segment operating results in the following manner:

- NGL inventory write downs are recorded as a cost of the Processing segment's merchant activities;
- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and
- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's propylene fractionation business.

For the third quarter of 2002 and 2001, we recognized $1.5 million and $9.7 million, respectively, of LCM adjustments primarily against NGL inventories. For the first nine months of 2002 and 2001, we recognized LCM adjustments of $6.2 million and $37.5 million, respectively, primarily against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or in some cases, offset). See Note 12 for a description of our commodity hedging activities.

4. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Life in Years	September 30, 2002	December 31, 2001
Plants and pipelines	5-35	$2,892,092	$1,398,843
Underground and other storage facilities	5-35	252,487	127,900
Transportation equipment	3-35	3,902	3,736
Land		20,313	15,517
Construction in progress		40,467	98,844
Total		3,209,261	1,644,840
Less accumulated depreciation		386,012	338,050
Property, plant and equipment, net		$2,823,249	$1,306,790

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts, and any gain or loss on disposition is included in income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to the

Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

Depreciation expense for the three months ended September 30, 2002 and 2001 was $20.6 million and $11.5 million, respectively. For the nine months ended September 30, 2002 and 2001, it was $48.6 million and $31.8 million, respectively.

5. 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 method. The investments in and advances to these unconsolidated affiliates are grouped according the operating segment to which they relate. For a general discussion of our operating segments, see Note 13.

We acquired three equity method unconsolidated affiliates as part of our acquisition of Diamond-Koch's propylene fractionation business (see Note 2). We purchased an aggregate 50% interest in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C. (collectively, "La Porte") which together own a private polymer grade propylene pipeline extending from Mont Belvieu to La Porte, Texas. In addition, we acquired 50% of the outstanding capital stock of Olefins Terminal Corporation ("OTC") which owns a polymer grade propylene storage facility and related dock infrastructure (located on the Houston Ship Channel) for loading waterborne propylene vessels. Both the La Porte and OTC investments are considered an integral part of our Splitter III propylene fractionation operations. These investments are classified as part of our Fractionation operating segment. The following table shows the

aggregate amount of investments in and advances to (and our ownership percentages in) unconsolidated affiliates at September 30, 2002 and December 31, 2001:

	Ownership Percentages	September 30, 2002	December 31, 2001
Accounted for on equity basis:			
Pipelines	19.88% to 50%	$212,834	$216,029
Fractionation	30% to 50%	97,952	93,329
Octane Enhancement	33.33%	57,302	55,843
Accounted for on cost basis:			
Processing	13.10%	33,000	33,000
Total		$401,088	$398,201

The following table shows equity in income (loss) of unconsolidated affiliates for the three and nine months ended September 30, 2002 and 2001:

	Ownership	Three Months Ended September 30,		Nine Months Ended September 30,	
	Percentages	2002	2001	2002	2001
Pipelines	19.88% to 50%	$2,705	$3,432	$ 9,506	$ 6,838
Fractionation	30% to 50%	2,103	1,948	5,714	4,201
Octane Enhancement	33.33%	1,155	909	7,038	6,311
Total		$5,963	$6,289	$22,258	$17,350

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 ("excess cost"). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. The excess cost amounts related to Promix, La Porte and Nemo are attributable to the tangible plant and pipeline assets of each entity, and are amortized against equity earnings from these entities in a manner similar to depreciation. The excess cost of Dixie includes amounts attributable to both goodwill and tangible pipeline assets, with that portion assigned to the pipeline assets being amortized in a manner similar to depreciation. The goodwill inherent in Dixie's excess cost is subject to periodic impairment testing and is not amortized. The following table summarizes our excess cost information:

	Initial Excess Cost	Unamortized balance at September 30, 2002	Unamortized balance at December 31, 2001	Amortization Charged to Equity Earnings during 2002	Amortization Period
Fractionation segment:					
Promix	$7,955	$6,695	$7,083	$298	20 years
La Porte	873	844	n/a	29	35 years
Pipelines segment:					
Dixie					
Attributable to pipeline assets	28,448	26,277	26,887	610	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,130	12,404	274	35 years
Nemo	727	703	718	16	35 years

The following tables present summarized income statement information for our unconsolidated investments accounted for under the equity method (for the periods indicated on a 100% basis).

Summarized Income Statement Data for the Three Months Ended

September 30, 2002			September 30, 2001		
Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income

Pipelines	$79,903	$12,379	$10,277	$77,884	$16,843	$13,556
Fractionation	21,180	6,874	6,842	19,363	6,213	6,283
Octane Enhancement	61,501	3,393	3,466	54,955	2,060	2,725
Total	$162,584	$22,646	$20,585	$152,202	$25,116	$22,564

	Summarized Income Statement Data for the Nine Months Ended					
	September 30, 2002			September 30, 2002		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Pipelines	$210,789	$36,569	$29,987	$187,197	$37,134	$28,854
Fractionation	60,360	18,719	18,686	55,364	13,633	13,944
Octane Enhancement	167,562	20,940	21,113	168,873	17,982	18,932
Total	$438,711	$76,228	$69,786	$411,434	$68,749	$61,730

Uncertainties regarding our investment in BEF

We have a 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. MTBE has come under scrutiny by various governmental agencies and environmental groups over the last few years because underground storage tanks filled with motor gasoline containing MTBE have leaked contaminating water supplies. Certain states, primarily California, have moved to ban or reduce MTBE use due to these concerns. The California ban takes effect during the first quarter of 2004. In addition, the U.S. Senate, in April 2002, passed an energy bill that includes a total ban on the use of MTBE, which if ultimately adopted would be effective in four years. The Senate bill is now in a conference committee with the U.S. House of Representatives for resolution. The U.S. House of Representatives energy bill, which passed in August 2001, contains no such ban. We can give no assurance as to whether the federal government or individual states will ultimately adopt legislation banning the use of MTBE.

In April 2002, a jury in California found three energy companies liable for polluting Lake Tahoe's drinking water with MTBE. While this decision sets no legal precedent, this was the first time that a jury has defined gasoline containing MTBE to be a "defective product". This development has no direct impact on BEF since our customer uses the MTBE we produce in its eastern U.S. operations.

In light of these developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently leaning towards a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical quality of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of the first quarter of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

6. RECENTLY ISSUED ACCOUNTING STANDARDS AFFECTING US

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interests method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001.

There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 was effective for our fiscal year that began January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized.

At December 31, 2001, our intangible assets were comprised of the values associated with the Shell natural gas processing agreement and the goodwill related to the 1999 MBA acquisition. In accordance with SFAS No. 141, we reclassified the MBA goodwill to a separate line item on our consolidated balance sheet apart from the Shell contract. The value of the Shell natural gas processing agreement will continue to be amortized over its remaining contract term of approximately 18 years; however, amortization of the MBA goodwill will cease. The MBA goodwill will be subject to periodic impairment testing in accordance with SFAS No. 142 due to its indefinite life. For additional information regarding our intangible assets and goodwill (including significant additions to both classes of assets as a result of the Diamond-Koch acquisitions), see Note 7.

In accordance with the transition provisions of SFAS No. 142, we have completed an impairment review of the December 31, 2001 MBA goodwill balance. Professionals in the business valuation industry were consulted regarding the assumptions and techniques used in our analysis. As a result of this review, no impairment loss was indicated. Any subsequent impairment losses stemming from future goodwill impairment studies will be reflected as a component of operating income in the Statements of Consolidated Operations.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In April 2002, the FASB issued SFAS No. 145, "Rescission of SFAS Statements No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." The purpose of this statement is to update, clarify and simplify existing accounting standards. We adopted this statement effective April 30, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31,

2002. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our intangible assets at September 30, 2002 and December 31, 2001:

		At September 30, 2002		At December 31, 2001	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$206,331	$(20,252)	$186,079	$(11,962)	$194,369
Mont Belvieu Storage II contracts	8,127	(174)	7,953		
Mont Belvieu Splitter III contracts	53,000	(1,010)	51,990		
Toca-Western natural gas processing contracts	11,096	(185)	10,911		
Toca-Western NGL fractionation contracts	20,041	(334)	19,707		
Venice contracts (a)	4,639		4,639		
MBA acquisition goodwill (b)	8,979			(1,122)	7,857
Total	$312,213	$(21,955)	$281,279	$(13,084)	$202,226

Notes:
(a) Amortization scheduled to begin when contracted-volumes begin to be processed in 2003.
(b) Amount reclassified to Goodwill on January 1, 2002 per transition provisions of SFAS 142.

At September 30, 2002, our intangible assets consisted of:

- the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999;
- certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002;
- certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002; and
- certain NGL-related contracts (the "Venice contracts") we acquired during the third quarter of 2002.

Our recorded intangible assets are comprised of the estimated values assigned to contract rights we own arising from agreements with customers. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of the entity. It is based on an analysis of all pertinent factors including (a) the expected use of the asset by the entity, (b) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (c) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause substantial costs or modifications to existing agreements, (d) the effects of obsolescence, demand, competition, and other economic factors and (e) the level of maintenance required to obtain the expected future cash flows.

The following table shows amortization expense associated with our intangible assets for the three and nine months ended September 30, 2002 and 2001:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Shell natural gas processing agreement	$2,763	$2,222	$8,290	$4,497
Mont Belvieu Storage II contracts	58		174	
Mont Belvieu Splitter III contracts	379		1,010	
Toca-Western natural gas processing contracts	185		185	
Toca-Western NGL fractionation contracts	334		334	
MBA acquisition goodwill (a)		112		337
Total	$3,719	$2,334	$9,993	$4,834

Notes:
(a) Effective January 1, 2002, goodwill is no longer subject to amortization under SFAS 142 guidelines.

The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term (currently $11.1 million annually from 2002 through 2019). The values of the propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized over the expected 20-year remaining life of the assets to which they relate.

The initial $4.6 million value of the Venice contracts will be amortized over 14 years beginning in the third quarter of 2003. The value of these contracts will increase to $6.6 million during the third quarter of 2003 when a counterparty to one of the contracts completes certain pipeline modifications.

For 2002, amortization expense attributable to intangible assets is currently estimated at $13.7 million. Based on information currently available, we expect that amortization expense relating to existing intangibles will increase to $14.8 million during each of the years 2003 through 2007.

Goodwill

At September 30, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (values as of September 30, 2002):

- $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,
- $7.9 million related to the July 1999 purchase of an additional ownership interest in MBA, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

At December 31, 2001, the goodwill associated with the MBA acquisition was recorded as part of our intangible assets.

Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized but will be annually assessed for recoverability. In addition, we will periodically review the reporting units to which the goodwill amounts relate if impairment indicators are evident. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, will be calculated and compared to its combined book value. Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment.

If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value.

Pro Forma impact of discontinuation of amortization of goodwill

The following table discloses the unaudited pro forma impact on earnings of discontinuing amortization of the MBA goodwill for the periods indicated:

	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2001
Reported net income	$75,007	$220,308
Discontinue goodwill amortization	111	333
Adjust minority interest expense	(1)	(3)
Adjusted net income	$75,117	$220,638

On a pro forma basis, earnings per Unit (both basic and diluted) were not affected by the discontinuation of goodwill amortization due to the immaterial nature of the pro forma adjustment.

8. DEBT OBLIGATIONS

Our debt consisted of the following at:

	September 30, 2002	December 31, 2001
Borrowings under:		
364-Day Term Loan, variable-rate, $150 million due December 2002, $450 million due March 2003 and $600 million due July 2003	$1,200,000	
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	$450,000
Senior Notes A, 8.25% fixed-rate, due March 2005	350,000	350,000
Multi-Year Revolving Credit facility, variable-rate, due November 2005	240,000	
364-Day Revolving Credit facility, variable-rate, due November 2003 (see Note 14)	173,000	
MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed-rate, $15 million due each December, 2002 through 2005	60,000	
Total principal amount	2,527,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,834	1,653
Less unamortized discount on:		
Senior Notes A	(90)	(117)
Senior Notes B	(237)	(258)
Less current maturities of debt	(1,215,000)	
Long-term debt	$1,313,507	$855,278

364-Day Term Loan and Seminole Notes

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day variable-rate term loan to fund the acquisition of Mid-America and Seminole from Williams on July 31, 2002. The term loan will generally bear interest at either (as defined within the loan agreement):

|X| the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent; or
|X| a Eurodollar Rate, with any rate in effect being increased by an appropriate applicable margin.

For the period in which this debt was outstanding, the weighted-average interest rate charged was 3.41%. We applied approximately $180 million in proceeds from our October 2002 equity offering to partially repay this Term Loan (see Note 14).

Seminole Notes. On July 31, 2002, Seminole had $60 million in 6.67% fixed-rate senior unsecured notes outstanding. The notes amortize by $15 million each December 1 through 2005. In accordance with generally accepted accounting principles, this debt is consolidated on our balance sheet because of our 78.4% ownership interest in Seminole.

Significant amendments to Multi-Year and 364-Day Revolving Credit facilities

The following significant amendments to the Multi-Year and 364-Day Revolving Credit facilities have been made during 2002:

|X| In April 2002, our total borrowing capacity under these two facilities was increased to $500 million, of which $87 million

was outstanding at September 30, 2002. The amount that we can borrow under the Multi-Year Revolving Credit facility was

increased by $20 million to $270 million. Likewise, the amount that we can borrow under the 364-Day Revolving Credit facility was increased by $80 million to $230 million.

|X| In April 2002, our debt covenants under these facilities were amended to allow us to exclude up to $50.0 million in commodity hedging losses we incurred during the first four months of 2002 from the calculation of Consolidated EBITDA (as defined in the revolving credit agreements). The amendment also increased the ratio of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities for certain periods.

|X| In July 2002, we amended our Multi-Year and 364-Day Revolving Credit facility to allow us to incur additional indebtedness for the interim financing of the Mid-America and Seminole pipeline systems. This amendment provided for an increase in the amount of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities. In addition, the negative covenant on Indebtedness (as defined in the revolving credit agreements) was amended to permit the Seminole Notes.

See Note 14 for description of an amendment executed in November 2002 whereby the maturity of the 364-Day Revolving Credit agreement was extended from November 15, 2002 to November 14, 2003.

During the first nine months of 2002, the range of interest rates paid on the Multi-Year and 364-Day Revolving Credit facilities was 2.32% to 2.59%. The weighted-average interest rates paid on Multi-Year and 364-Day Revolving Credit facilities during the period was 2.31% and 2.46%, respectively.

Guarantor relationships

Enterprise Products Partners L.P. acts as guarantor of certain of the Operating Partnership's debt obligations. This parent-subsidiary guaranty provision exists under our 364-Day Term Loan; Senior Notes A and B; MBFC Loan; and the Multi-Year and 364-Day Revolving Credit facilities.

Letters of Credit

At September 30, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility of which $2.4 million was outstanding.

Other

The indentures under which Senior Notes A and B and the MBFC Loan were issued contain various restrictive covenants. We were in compliance with these covenants at September 30, 2002.

The 364-Day Term Loan, Multi-Year Revolving Credit facility, and 364-Day Revolving Credit facility contain various affirmative and negative covenants applicable to the Operating Partnership. The covenants of the 364-Day Term Loan are similar to those required under the Multi-Year and 364-Day Revolving Credit facilities. As such, the 364-Day Term Loan agreement contains covenants related to our ability to incur certain indebtedness, grant certain liens, enter into certain merger or consolidation transactions, and make certain investments. In addition, the 364-Day Term Loan requires us to satisfy certain financial covenants at the end of each fiscal quarter. We were in compliance with the covenants of these three debt agreements at September 30, 2002.

The Seminole Note agreements contain various restrictive covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at September 30, 2002.

9. CAPITAL STRUCTURE

Conversion of EPCO Subordinated Units to Common Units

As a result of the Company satisfying certain financial tests, 10,704,936 (or 25%) of EPCO's Subordinated Units converted to Common Units on May 1, 2002. Should the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25%

of the Subordinated Units would undergo an early conversion to Common Units on May 1, 2003. The remaining 50% of Subordinated Units would convert on August 1, 2003 should the balance of the conversion requirements be met. The conversion(s) will have no impact upon our earnings per unit since the Subordinated Units are already included in both the basic and fully diluted EPU calculations.

Conversion of Shell Special Units to Common Units

In accordance with existing agreements with Shell, 19.0 million of Shell's non-distribution bearing Special Units converted to distribution-bearing Common Units on August 1, 2002. The remaining 10.0 million Special Units will convert to Common Units on a one-for-one basis in August 2003. These conversions have a dilutive impact on basic EPU.

Treasury Units

During the first quarter of 1999, the Operating Partnership established the EPOLP 1999 Grantor Trust (the "Trust") to fund future obligations under EPCO's long-term incentive plan (through the exercise of Common Unit options granted to directors of the General Partner and EPCO employees who participate in the business of the Operating Partnership). The Common Units purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. At September 30, 2002, the Trust held 427,200 Common Units that are classified as Treasury Units. The Trust purchased 100,000 Common Units during the first nine months of 2002 at a cost of $2.4 million.

Beginning in July 2000 and later modified in September 2001, the General Partner authorized the Company (specifically, "Enterprise Products Partners L.P." in this context) and the Trust to repurchase up to 2.0 million of our publicly-held Common Units (the "Buy-Back Program"). The repurchases will be made during periods of temporary market weakness at price levels that would be accretive to our remaining Unitholders. Under the terms of the original Buy-Back Program, Common Units repurchased by the Company were to be retired and Common Units repurchased by the Trust were to remain outstanding and be accounted for as Treasury Units.

In April 2002, management modified the Buy-Back Program to treat Common Units repurchased by the Company as Treasury Units. For accounting purposes, Units repurchased by the Company will be held in treasury to fund future obligations under EPCO's long-term incentive plan (i.e, used for the same intent as that contemplated for the Common Units repurchased by the Trust). The Company purchased 432,000 Common Units during the first nine months of 2002 at a cost of $10.3 million. At September 30, 2002, an additional 618,400 Common Units could be repurchased under the Buy-Back Program.

During the second quarter of 2002, 51,959 Common Units were reissued from the Company's Treasury Units at their weighted-average cost of $1.2 million to fulfill our obligations under certain employee Unit option agreements of EPCO.

Comprehensive Income

We report comprehensive income or loss in our Statements of Consolidated Partners' Equity and Comprehensive Income. For the nine months ended September 30, 2001, the cumulative transition adjustment resulting from the adoption of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted, was the only item of other comprehensive income for us and reduced Comprehensive Income by $2.3 million.

10. 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 the 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 the period. In a period of operating losses, the Special Units are excluded from the calculation of diluted earnings per Unit due to their antidilutive effect. 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 nine months ended September 30, 2002 and 2001.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Income before minority interest	$36,146	$75,774	$41,293	$222,553
General partner interest	(2,774)	(1,599)	(6,668)	(3,969)
Income before minority interest available to Limited Partners	33,372	74,175	34,625	218,584
Minority interest	(1,296)	(767)	(1,326)	(2,245)
Net income available to Limited Partners	$32,076	$73,408	$33,299	$216,339
BASIC EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$33,372	$74,175	$34,625	$218,584
Net income available to Limited Partners	$32,076	$73,408	$33,299	$216,339
Denominator				
Common Units outstanding	125,502	98,994	112,699	94,698
Subordinated Units outstanding	32,115	42,820	36,820	42,820
Total	157,617	141,814	149,519	137,518
Basic Earnings per Unit				
Income before minority interest available to Limited Partners	$ 0.21	$ 0.52	$ 0.23	$ 1.59
Net income available to Limited Partners	$ 0.20	$ 0.52	$ 0.22	$ 1.57
DILUTED EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$33,372	$74,175	$34,625	$218,584
Net income available to Limited Partners	$32,076	$73,408	$33,299	$216,339
Denominator				
Common Units outstanding	125,502	98,994	112,699	94,698
Subordinated Units outstanding	32,115	42,820	36,820	42,820
Special Units outstanding	16,402	30,392	24,755	32,120
Total	174,019	172,206	174,274	169,638
Diluted Earnings per Unit				
Income before minority interest available to Limited Partners	$ 0.19	$ 0.43	$ 0.20	$ 1.29
Net income available to Limited Partners	$ 0.18	$ 0.43	$ 0.19	$ 1.28

11. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows:

	Nine Months Ended September 30,	
	2002	2001
(Increase) decrease in:		
Accounts and notes receivable	$(49,675)	$ 153,224
Inventories	(144,746)	(44,755)
Prepaid and other current assets	16,183	(8,732)
Other assets	(3,326)	(122)
Increase (decrease) in:		
Accounts payable	54,198	(79,413)
Accrued gas payable	170,407	(153,039)
Accrued expenses	(5,884)	(6,500)
Accrued interest	(9,478)	9,311
Other current liabilities	372	13,540
Other liabilities	(145)	124
Net effect of changes in operating accounts	$ 27,906	$(116,362)

During the first nine months of 2002, we completed $1.6 billion in business acquisitions of which the purchase price allocations of each affected various balance sheet accounts. See Note 2 for information regarding the allocation of the purchase price for these acquisitions.

We record various financial instruments relating to commodity positions and interest rate swaps at their respective fair values using mark-to-market accounting. For the nine months ended September 30, 2002, we recognized a net $12.8 million in non-cash mark-to-market losses related to decreases in the fair value of these financial instruments, primarily in our commodity financial instruments portfolio. For the nine months ended September 30, 2001, we recognized a net $39.4 million in non-cash mark-to-market income from our financial instruments portfolio.

During the third quarter of 2002, we made the first of two cash payments to acquire certain processing-related contract rights connected to the Venice gas processing facility. Of the initial $4.6 million value of this intangible asset group, $2.6 million was reclassified from construction-in-progress and $2.0 million represented the actual cash payment made to the third-party. The amount spent on construction-in-progress was reclassified due to the direct linkage between the capital expenditures made and the successful negotiation of the Venice contracts. The remaining $2.0 million is scheduled to be paid during the third quarter of 2003.

Cash and cash equivalents at September 30, 2002, per the Statements of Consolidated Cash Flows, excludes $7.3 million of restricted cash. This restricted cash represents amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the NYMEX exchange.

12. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in our Processing segment. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Commodity financial instruments

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities (or hedging strategies) is to hedge exposure to price risks associated with natural gas, NGL inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in our Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price we charge certain of our customers for natural gas.

We have adopted a financial commodity and commercial policy to manage our exposure to the risks of our natural gas and NGL businesses. The objective of these policies is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. Under these policies, we enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than one month) and long-term basis, generally not to exceed 24 months. The General Partner oversees our hedging strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policies (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policies.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. When financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these ineffective instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices.

We recognized a loss of $52.3 million in the first nine months of 2002 from our commodity hedging activities, of which $45.1 million was attributable to the first quarter of 2002. These losses are treated as an increase in operating costs and expenses in our Statements of Consolidated Operations. Of this amount, $41.7 million has been realized (e.g., paid out to counterparties). The remaining $10.6 million represents the negative change in value of the open positions between December 31, 2001 and September 30, 2002 (based on market prices at those dates). The market value of our open positions at September 30, 2002 was $2.7 million payable (a loss).

For the first nine months of 2001, we recognized income of $118.6 million from these activities of which $5.6 million was recorded in the first quarter; $64.7 million in the second quarter; and $48.3 million in the third quarter. Of the $118.6 million in commodity hedging income recorded during the first nine months of 2001, $34.6 million was attributable to the market value of open positions at September 30, 2001.

Interest rate swaps

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the Company's Senior Notes and MBFC Loan. We manage a portion of our exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding interest rate swaps is to manage debt service costs by converting a portion of fixed-rate debt into

variable-rate debt or a portion of variable-rate debt into fixed-rate debt. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount.

The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements. At December 31, 2001 and September 30, 2002, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010. Under this agreement, we exchanged a fixed-rate of 8.70% for a market-based variable-rate. If it elects to do so, the counterparty may terminate this swap in March 2003.

We recognized income of $0.8 million during the first nine months of 2002 from our interest rate swap that is treated as a reduction of interest expense (with $0.1 million recorded in the third quarter of 2002). The market value of the interest rate swap at September 30, 2002 was $1.6 million. During the first nine months of 2001, we were party to several interest rate swaps having a variety of terms and notional amounts. We recognized $13.2 million in income from these instruments during the first nine months of 2001.

13. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

We have five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. The 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 Chief Executive Officer of the General Partner. Pipelines consists of both liquids and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Processing includes the natural gas processing business and its related merchant activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and other plant support functions.

We evaluate segment performance based on gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

Gross operating margin by segment includes intersegment and intrasegment revenues (offset by corresponding intersegment and intrasegment expenses within the segments), which are generally based on transactions made at market-related rates. Our intersegment and intrasegment activities include, but are not limited to, the following types of transactions:

- NGL fractionation revenues from separating our NGL raw-make inventories into distinct NGL products using our fractionation plants for our merchant activities group (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);
- liquids pipeline revenues from transporting our merchant volumes from the gas processing plants on our pipelines to our NGL fractionation facilities (an intersegment revenue of Pipelines offset by an intersegment expense of Processing); and,
- the sale of our NGL equity production extracted by our gas processing plants to our merchant activities group (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany (both intersegment and intrasegment) accounts and transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. Our equity investments with industry partners are a vital component of our business strategy and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. 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 example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our merchant businesses. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States.
Most of our plant-based operations are located primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. Our merchant businesses are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

A reconciliation of segment gross operating margin to consolidated income before provision for taxes and minority interest follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Total segment gross operating margin	$107,205	$110,849	$200,556	$314,997
Depreciation and amortization	(24,292)	(13,071)	(58,491)	(34,893)
Retained lease expense, net	(2,274)	(2,660)	(6,852)	(7,980)
(Gain) loss on sale of assets	6	4	(6)	391
Selling, general and administrative	(12,289)	(7,716)	(27,991)	(21,621)
Consolidated operating income	68,356	87,406	107,216	250,894
Interest expense	(30,690)	(12,610)	(68,235)	(35,928)
Interest income from unconsolidated affiliates	28		120	31
Dividend income from unconsolidated affiliates		392	2,196	2,024
Interest income-other	434	861	2,009	6,338
Other,net	74	(275)	43	(806)
Consolidated income before taxes and minority interest	$ 38,202	$ 75,774	$ 43,349	$222,553

Information by operating 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 external customers:							
Three months ended Sept. 30, 2002	$179,781	$174,303	$588,828		$401		$943,313
Three months ended Sept. 30, 2001	75,842	127,687	519,165		635		723,329
Nine months ended Sept. 30, 2002	458,548	411,973	1,519,803		1,300		2,391,624
Nine months ended Sept. 30, 2001	252,087	313,832	1,951,176		1,946		2,519,041
Intersegment and intrasegment revenues:							
Three months ended Sept. 30, 2002	59,737	27,469	123,049		100	$(210,355)	
Three months ended Sept. 30, 2001	41,273	22,464	244,145		99	(307,981)	
Nine months ended Sept. 30, 2002	149,237	77,557	390,278		302	(617,374)	
Nine months ended Sept. 30, 2001	127,058	67,874	486,111		290	(681,333)	
Equity income in unconsolidated affiliates:							
Three months ended Sept. 30, 2002	2,102	2,705		$1,156			5,963
Three months ended Sept. 30, 2001	1,948	3,432		909			6,289
Nine months ended Sept. 30, 2002	5,714	9,506		7,038			22,258
Nine months ended Sept. 30, 2001	4,201	6,838		6,311			17,350
Total revenues:							
Three months ended Sept. 30, 2002	241,620	204,477	711,877	1,156	501	(210,355)	949,276
Three months ended Sept. 30, 2001	119,063	153,583	763,310	909	734	(307,981)	729,618
Nine months ended Sept. 30, 2002	613,499	499,036	1,910,081	7,038	1,602	(617,374)	2,413,882
Nine months ended Sept. 30, 2001	383,346	388,544	2,437,287	6,311	2,236	(681,333)	2,536,391
Total gross operating margin by segment:							
Three months ended Sept. 30, 2002	34,585	63,887	8,417	1,156	(840)		107,205
Three months ended Sept. 30, 2001	35,189	22,415	52,026	909	310		110,849
Nine months ended Sept. 30, 2002	92,815	128,745	(26,141)	7,038	(1,901)		200,556
Nine months ended Sept. 30, 2001	93,660	65,234	148,536	6,311	1,256		314,997
Segment assets:							
At September 30, 2002	437,362	2,198,230	137,699		9,491	40,467	2,823,249
At December 31, 2001	357,122	717,348	124,555		8,921	98,844	1,306,790
Investments in and advances to unconsolidated affiliates:							
At September 30, 2002	97,952	212,834	33,000	57,302			401,088
At December 31, 2001	93,329	216,029	33,000	55,843			398,201
Intangible Assets:							
At September 30, 2002	71,697	7,953	201,629				281,279
At December 31, 2001	7,857		194,369				202,226
Goodwill:							
At September 30, 2002	81,547						81,547

Consolidated revenues for the third quarter of 2002 increased $219.7 million over those of the third quarter of 2001. The increase is primarily due to businesses we have acquired during 2002 such as Splitter III, Mid-America and Seminole (see Note 2). Consolidated revenues for the first nine months of 2002 decreased $122.5 million from those recorded during the same period in 2001. The decrease in year-to-date revenues is primarily due to lower NGL prices which negatively affected Processing revenues offset by the positive effect of revenues from businesses acquired during 2002.

Gross operating margin for the third quarter of 2002 decreased $3.6 million compared to the third quarter of 2001.

The decrease was primarily due to a $43.6 million decline in gross operating margin from Processing offset by a $41.5 million increase in margin from our Pipelines segment. The quarter-to-quarter gross operating margin variance in Processing is primarily

attributable to a $49.7 million negative change in commodity hedging results between the periods: the 2001 period includes $48.3 million of income from these activities whereas the 2002 period includes a loss of $1.4 million. The $41.5 million positive change in gross operating margin from the Pipelines segment is primarily due to the acquisition of Mid-America and Seminole (which added $30.1 million in gross operating margin to our third quarter of 2002 results) and increased earnings from our Mont Belvieu storage facilities (including those we acquired in January 2002 from Diamond-Koch).

Gross operating margin for the nine months ended September 30, 2002 decreased $114.4 million compared to the same period during 2001. The decrease in year-to-date gross operating margin is principally due to a $174.7 million decrease in our Processing segment offset by a $63.5 million increase from our Pipelines segment. The largest contributing factor to the decline in Processing was a $170.9 million negative change in commodity hedging results between the periods. We recorded $118.6 million in income from certain natural-gas based commodity hedging strategies during the first nine months of 2001. These strategies did not perform as anticipated during the first quarter of 2002, leading us to exit many of these strategies. We recorded a loss of $52.3 million from our commodity hedging activities during the first nine months of 2002, of which $45.1 million was recognized during the first quarter, $5.8 million during the second quarter and $1.4 million during the third quarter. The increase in earnings from our Pipelines segment is primarily due to the positive effect of businesses we have acquired over the last two years (Mid-America, Seminole, Acadian Gas and Mont Belvieu storage operations).

Since January 1, 2002, segment assets have increased $1.5 billion primarily due to acquisitions completed during the year (see Note 2). Intangible assets increased $79.1 million since January 1, 2002 primarily the result of the contract-based intangible assets we acquired from Diamond-Koch and Toca-Western (see Note 7). Goodwill was $81.5 million at September 30, 2002 due to the goodwill we added as a result of the Diamond-Koch acquisition and the reclassification of the goodwill associated with the 1999 MBA acquisition (see Note 7).

14. SUBSEQUENT EVENTS

Common Unit offering in October 2002

On October 3, 2002, we completed a public offering of 9.8 million Common Units. The Common Units were priced at $18.99 per Unit, based on the closing price of our Common Units on the NYSE on October 2, 2002. We granted the underwriters an option to purchase up to 1.47 million additional Common Units to cover over-allotments. The net proceeds from the offering of approximately $180 million were used to repay a portion of the debt incurred to finance the Mid-America and Seminole acquisitions. The application of these proceeds met the payment required under the 364-Day Term Loan scheduled for December 2002.

Amendment of 364-Day Revolving Credit Agreement

On October 28, 2002, our Operating Partnership completed an amendment which refinanced its 364-Day Revolving Credit facility. The amendment, which has an effective date of November 15, 2002, extends the maturity of the current unsecured 364-Day Revolving Credit facility from November 15, 2002 to November 14, 2003.

PART I. FINANCIAL INFORMATION.

Item 1B. CONSOLIDATED FINANCIAL STATEMENTS.

Enterprise Products Operating L.P.
Consolidated Balance Sheets
(Dollars in thousands)

ASSETS	September 30, 2002 (unaudited)	December 31, 2001
Current Assets		
Cash and cash equivalents (includes restricted cash of $7,273 at September 30, 2002 and $5,752 at December 31, 2001)	$ 61,835	$ 137,823
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,039 at September 30, 2002 and $20,642 at December 31, 2001	322,441	256,927
Accounts receivable - affiliates	1,622	4,405
Inventories	227,058	62,942
Prepaid and other current assets	46,221	50,207
Total current assets	659,177	512,304
Property, Plant and Equipment, Net	2,823,249	1,306,790
Investments in and Advances to Unconsolidated Affiliates	401,088	398,201
Intangible assets, net of accumulated amortization of $21,955 at September 30, 2002 and $13,084 at December 31, 2001	281,279	202,226
Goodwill	81,547	
Other Assets	9,776	5,201
Total	$4,256,116	$2,424,722
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$1,215,000	
Accounts payable - trade	85,972	$54,269
Accounts payable - affiliate	52,381	33,691
Accrued gas payables	397,442	227,035
Accrued expenses	24,766	22,233
Accrued interest	15,491	24,302
Other current liabilities	45,028	44,767
Total current liabilities	1,836,080	406,297

Long-Term Debt	1,313,507	855,278
Other Long-Term Liabilities	8,020	8,061
Minority Interest	59,334	1,468
Commitments and Contingencies		
Partners' Equity		
Limited Partner	1,037,251	1,148,124
General Partner	10,584	11,716
Parent's Units acquired by Trust	(8,660)	(6,222)
Total Partners' Equity	1,039,175	1,153,618
Total	$4,256,116	$2,424,722

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Operating L.P.
Statements of Consolidated Operations
(Dollars in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
REVENUES				
Revenues from consolidated operations	$943,313	$723,329	$2,391,624	$2,519,041
Equity income in unconsolidated affiliates	5,963	6,289	22,258	17,350
Total	949,276	729,618	2,413,882	2,536,391
COST AND EXPENSES				
Operating costs and expenses	868,631	634,496	2,278,675	2,263,876
Selling, general and administrative	12,271	7,644	27,872	22,230
Total	880,902	642,140	2,306,547	2,286,106
OPERATING INCOME	68,374	87,478	107,335	250,285
OTHER INCOME (EXPENSE)				
Interest expense	(30,689)	(12,610)	(68,234)	(35,928)
Interest income from unconsolidated affiliates	28		120	15
Dividend income from unconsolidated affiliates		392	2,196	2,024
Interest income - other	576	1,018	2,396	6,789
Other, net	74	(275)	(68)	(806)
Other income (expense)	(30,011)	(11,475)	(63,590)	(27,906)
INCOME BEFORE PROVISION FOR TAXES AND MINORITY INTEREST	38,363	76,003	43,745	222,379
PROVISION FOR TAXES	(2,056)		(2,056)	
INCOME BEFORE MINORITY INTEREST	36,307	76,003	41,689	222,379
MINORITY INTEREST	(988)	(46)	(1,074)	(113)
NET INCOME	$ 35,319	$ 75,957	$ 40,615	$ 222,266

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Operating L.P.
Statements of Consolidated Cash Flows
(Dollars in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2002	2001
OPERATING ACTIVITIES		
Net income	$ 40,615	$222,266
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization	62,907	37,245
Equity in income of unconsolidated affiliates	(22,258)	(17,350)
Distributions received from unconsolidated affiliates	40,114	30,602
Leases paid by EPCO	6,852	7,980
Minority interest	1,074	113
Loss (gain) on sale of assets	6	(392)
Deferred income tax expense	529	
Changes in fair market value of financial instruments	12,830	(39,429)
Net effect of changes in operating accounts	23,055	(117,669)
Operating activities cash flows	165,724	123,366

INVESTING ACTIVITIES		
Capital expenditures	(46,958)	(92,641)
Proceeds from sale of assets	18	567
Business acquisitions, net of cash acquired	(1,615,298)	(225,665)
Acquisition of intangible asset	(2,000)	
Investments in and advances to unconsolidated affiliates	(13,193)	(119,865)
Investing activities cash flows	(1,677,431)	(437,604)
FINANCING ACTIVITIES		
Long-term debt borrowings	1,883,000	449,716
Long-term debt repayments	(270,000)	
Debt issuance costs	(16,522)	(3,126)
Cash distributions to partners	(159,510)	(119,084)
Cash distributions to minority interest	(173)	(58)
Cash contribution from General Partner	39	
Cash contributions from minority interest	1,324	134
Parent's Units acquired by consolidated Trust	(2,439)	(8,838)
Increase in restricted cash associated with commodity hedging activities	(1,521)	(9,032)
Financing activities cash flows	1,434,198	309,712
CASH CONTRIBUTION FROM EPCO		
NET CHANGE IN CASH AND CASH EQUIVALENTS	(77,509)	(4,526)
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	58,446
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 54,562	$ 53,920

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 September 30, 2002 and consolidated results of operations and cash flows for the three and nine months ended September 30, 2002 and 2001. 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 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 generally accepted accounting principles 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 (File No. 333-93239-01) for the year ended December 31, 2001.

The results of operations for the three and nine months ended September 30, 2002 are not necessarily indicative of the results to be expected for the full year.

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

Certain abbreviated entity names and other capitalized terms are described 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.

Provision for taxes

As a result of our acquisition of Seminole on July 31, 2002 (see Note 2), we now recognize income tax expense related to this entity's operations. Our provision for taxes is computed using the liability method and is provided on all temporary differences between the financial basis and the tax basis of Seminole's assets and liabilities.

2. BUSINESS ACQUISITIONS

Acquisition of Mid-America and Seminole in July 2002

On July 31, 2002, we acquired equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America," formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole"). The purchase price of the acquisitions was approximately $1.2 billion (subject to certain post-closing purchase price adjustments) .

The acquisition of Mid-America and Seminole significantly enhances our existing asset base by:

|X| accessing NGL-rich natural gas production in major North American natural gas producing regions;
|X| expanding our integrated natural gas and NGL network;
|X| providing access to new end markets for NGL products; and
|X| increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The combination of these assets with our existing assets also creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States, and provides additional access to new end markets for NGL products.

The acquisitions include a 98% ownership interest in Mapletree, LLC, which is the sole owner of Mid-America and certain propane terminals and storage facilities. Mid-America owns a major NGL pipeline system consisting of three NGL pipelines, with 7,226 miles of pipeline. Mid-America's 2,548-mile Rocky Mountain system transports mixed NGLs from the Rocky Mountain Overthrust and San Juan basin areas to the Hobbs hub located on the Texas-New Mexico border. Its 2,740-mile Conway North segment links the large NGL hub at Conway, Kansas to the upper Midwest; its 1,938-mile Conway South system connects the Conway hub with Kansas refineries and transports mixed NGLs from Conway, Kansas to the Hobbs hub. We also acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole. The Seminole pipeline consists of a 1,281-mile pipeline which transports mixed NGLs and NGL products from the Hobbs hub and the Permian basin to Mont Belvieu, Texas.

The funding of these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"; see Note 8 for a description of this debt). Our plans for permanent financing of these acquisitions include the issuance of equity (by our Limited Partner) and debt in amounts which are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet. The post-closing purchase price adjustments are expected to be completed during the fourth quarter of 2002. These acquisitions did not require any material governmental approvals.

Acquisition of Diamond-Koch propylene fractionation business in February 2002

In February 2002, we purchased various propylene fractionation assets and certain inventories of refinery grade propylene, propane, and polymer grade propylene from Diamond-Koch. These include a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas (the "Splitter III" facility), a 50% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas, and varying interests in several supporting distribution pipelines and related equipment. Splitter III has the capacity to produce approximately 41 MBPD of polymer grade propylene. These assets are part of our Mont Belvieu propylene fractionation operations, which is part of the Fractionation segment. The purchase price of $239.0 million was funded by a drawdown on our Multi-Year and 364-Day Revolving Credit facilities (see Note 8).

Acquisition of Diamond-Koch storage business in January 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facilities consist of 30 salt dome storage caverns with a useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene, polymer grade propylene, chemical grade propylene and refinery grade propylene).

The facilities are located in Mont Belvieu, Texas and serve the largest petrochemical and refinery complex in the United States. Collectively, these facilities represent the largest underground storage operation of its kind in the world. The size and location of the business provide it with a competitive position to increase its services to expanding Gulf Coast petrochemical complexes. These assets are part of our Mont Belvieu storage operations, which is part of the Pipelines segment. The purchase price of $129.6 million was funded by utilizing cash on hand.

Other minor acquisitions completed during 2002

We completed the purchase of an additional interest in our Mont Belvieu NGL fractionator from ChevronTexaco and the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources during the second quarter of 2002. Due to the immaterial nature of these two transactions, our discussion of each is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. In September 2002, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. ChevronTexaco was required to sell its 12.5% interest in a consent order by the FTC as a condition of approving the merger between Chevron and Texaco. The effective date of the purchase was June 1, 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. In June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant. The transaction was finalized in September 2002 with the expiration of certain preferential purchase rights to the facility held by third-parties.

Acadian Gas post-closing adjustments completed in April 2002

In April 2002, we finalized the post-closing purchase price adjustment associated with our April 2001 acquisition of Acadian Gas. Acadian Gas was acquired from an affiliate of Shell and is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. As a result, we paid Shell $18.0 million for various working capital items, of which the majority were related to natural gas inventories.

Allocation of amounts paid during 2002

The acquisitions and post-closing adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	D-K Storage	D-K Propylene Fractionation	Mid-America and Seminole	Other	Total
Accounts and notes receivable			$ 11,777		$ 11,777
Accounts receivable - affiliates			7,799		7,799
Inventories		$ 4,994	14,376		19,370
Prepaids and other current assets	$890	3,148	8,445		12,483
Property, plant and equipment	120,571	96,772	1,284,337	$19,043	1,520,723
Investments in unconsolidated affiliates		7,550			7,550
Intangible assets	8,127	53,000		31,137	92,264
Goodwill		73,691			73,691
Other assets			2,396		2,396
Accounts payable - affiliates			(7,799)		(7,799)
Accrued expenses			(5,733)	(2,457)	(8,190)
Accrued interest			(667)		(667)
Other current liabilities		(107)	(11,254)	10,993	(368)

Long-term debt			(60,000)		(60,000)
Other long-term liabilities			(90)		(90)
Minority interest			(55,641)		(55,641)
Total purchase price	$129,588	$239,048	$1,187,946	$58,716	$1,615,298

The fair value estimates for the D-K storage; D-K propylene fractionation; Mid-America and Seminole; and Toca-Western acquisitions were developed by independent appraisers using recognized business valuation techniques. The allocation of the D-K storage purchase price is preliminary pending the results of a repermitting process expected to be complete during the fourth quarter of 2002. Also, the Mid-America and Seminole allocations are preliminary pending completion of a final review of these businesses which is expected to be completed during the first quarter of 2003. The purchase price allocations related to the Acadian Gas post-closing adjustment and the acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator are based on previously issued fair value reports.

The purchase price paid for the propylene fractionation business resulted in $73.7 million in goodwill. The goodwill primarily represents the value management has attached to future earnings improvements and to the strategic location of the assets. Earnings from the propylene business are expected to improve substantially from the last few years with the years 2003 and 2004 projected to be peak years in the petrochemical business cycle.

The propylene fractionation assets are located in Mont Belvieu, Texas on the Gulf Coast, the largest natural gas liquids and petrochemical marketplace in the U.S. The assets have access to substantial supply from major Gulf Coast and central U.S. producers of refinery grade propylene. The polymer grade products produced at the facility have competitive advantages because of distribution direct to customers via affiliated pipelines and through an affiliated export facility.

Combined pro forma effect of Mid-America, Seminole, Diamond-Koch and Acadian Gas business acquisitions

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the following acquired businesses:

|X| D-K storage (acquired January 1, 2002) and propylene fractionation (acquired February 1, 2002);
|X| Mid-America and Seminole (both acquired July 31, 2002); and
|X| Acadian Gas (acquired April 1, 2001).

Our historical Statements of Consolidated Operations reflect the operations of each acquired business since their respective acquisition dates.

The following pro forma information have been prepared as if the acquisitions had been completed on January 1 of the respective periods presented as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available to and certain estimates and assumptions made by management and, as a result, are not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
PRO FORMA EARNINGS DATA				
Revenues	$988,512	$870,448	$2,595,587	$3,196,252
Operating income	82,685	113,706	187,092	315,298
Net income	$ 43,052	$ 78,900	$ 75,177	$ 222,400

Pro forma net income for each period includes (among other pro forma adjustments) the impact of interest expense associated with the $1.2 billion 364-Day Term Loan related to the Mid-America and Seminole acquisitions. The pro forma earnings data assume that the entire $1.2 billion 364-Day Term Loan is outstanding during all periods presented. To the extent that we refinance the Mid-America and Seminole acquisitions using equity offerings, interest expense will be reduced as the proceeds from such offerings are contributed to us and applied against outstanding debt. In October 2002, our Limited Partner completed an equity offering of 9.8 million Common Units which generated proceeds of approximately $180 million after expenses. The proceeds from this offering were contributed to us and used to partially repay debt. Pro forma interest expense does not reflect the impact of the Limited Partner's October 2002 contribution.

Total pro forma interest expense for the three months ending September 30, 2002 and 2001 was $35.8 million and $31.5 million, respectively. Included in these amounts is the effect of the one-year amortization of the debt issuance costs we incurred to secure the 364-Day Term Loan ($1.2 million in pro forma amortization expense for the 2002 period and $3.8 million for the 2001 period).

Additionally, the pro forma interest expense adjustment directly attributable to the 364-Day Term Loan was $3.2 million for the third quarter of 2002 and $9.6 million for the third quarter of 2001. Our historical results for the third quarter of 2002 already include the effects of the 364-Day Term Loan for two months (August and September).

Total pro forma interest expense for the nine months ending September 30, 2002 and 2001 was $103.0 million and $91.1 million, respectively. The pro forma adjustment relating to the amortization of the debt issuance costs was $8.8 million for the 2002 period and $11.3 million for the 2001 period. The pro forma interest expense adjustment directly attributable to the 364-Day Term Loan was $22.4 million for the 2002 period and $28.8 million for the 2001 period.

3. INVENTORIES

Our inventories were as follows at the dates indicated:

	September 30, 2002	December 31, 2001

Working inventory	$153,802	$29,393
Forward-sales inventory	51,732	33,549
Peak Season inventory	21,524	
Inventory	$227,058	$62,942

A description of each inventory is as follows:

- Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemicals that are available for sale. This inventory is valued at the lower of average cost or market, with "market" being determined by spot-market related prices.
- The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with "market" being defined as the weighted-average of the sales prices of the forward sales contracts.
- The peak season inventory is comprised of segregated NGL volumes that are expected to be sold outside of the current summer-winter season and is valued at the lower of average cost or market, with "market" being determined by spot-market related prices. These volumes are generally expected to be sold within the next twelve months, but may be held for longer periods depending on market conditions.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost 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 and generally affect our segment operating results in the following manner:

- NGL inventory write downs are recorded as a cost of the Processing segment's merchant activities;
- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and
- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's propylene fractionation business.

For the third quarter of 2002 and 2001, we recognized $1.5 million and $9.7 million, respectively, of LCM adjustments primarily against NGL inventories. For the first nine months of 2002 and 2001, we recognized LCM adjustments of $6.2 million and $37.5 million, respectively, primarily against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or in some cases, offset). See Note 11 for a description of our commodity hedging activities.

4. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Life in Years	September 30, 2002	December 31, 2001
Plants and pipelines	5-35	$2,892,092	$1,398,843
Underground and other storage facilities	5-35	252,487	127,900
Transportation equipment	3-35	3,902	3,736
Land		20,313	15,517
Construction in progress		40,467	98,844
Total		3,209,261	1,644,840
Less accumulated depreciation		386,012	338,050
Property, plant and equipment, net		$2,823,249	$1,306,790

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts, and any gain or loss on disposition is included in income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to the Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

Depreciation expense for the three months ended September 30, 2002 and 2001 was $20.6 million and $11.5 million, respectively. For the nine months ended September 30, 2002 and 2001, it was $48.6 million and $31.8 million, respectively.

5. 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 method. The investments in and advances to these unconsolidated affiliates are grouped according the operating segment to which they relate. For a general discussion of our operating segments, see Note 12.

We acquired three equity method unconsolidated affiliates as part of our acquisition of Diamond-Koch's propylene fractionation business (see Note 2). We purchased an aggregate 50% interest in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C. (collectively, "La Porte") which together own a private polymer grade propylene pipeline extending from Mont Belvieu to La Porte, Texas. In addition, we acquired 50% of the outstanding capital stock of Olefins Terminal Corporation ("OTC") which owns a polymer grade propylene storage facility and related dock infrastructure (located on the Houston Ship Channel) for loading waterborne propylene vessels. Both the La Porte and OTC investments are considered an integral part of our Splitter III propylene fractionation operations. These investments are classified as part of our Fractionation operating segment.

The following table shows the aggregate amount of investments in and advances to (and our ownership percentages in) unconsolidated affiliates at September 30, 2002 and December 31, 2001:

	Ownership Percentages	September 30, 2002	December 31, 2001
Accounted for on equity basis:			
Pipelines	19.88% to 50%	$212,834	$216,029
Fractionation	30% to 50%	97,952	93,329
Octane Enhancement	33.33%	57,302	55,843
Accounted for on cost basis:			
Processing	13.10%	33,000	33,000
Total		$401,088	$398,201

The following table shows equity in income (loss) of unconsolidated affiliates for the three and nine months ended September 30, 2002 and 2001:

	Ownership	Three Months Ended September 30,		Nine Months Ended September 30,	
	Percentages	2002	2001	2002	2001
Pipelines	19.88% to 50%	$2,705	$3,432	$9,506	$6,838
Fractionation	30% to 50%	2,103	1,948	5,714	4,201
Octane Enhancement	33.33%	1,155	909	7,038	6,311
Total		$5,963	$6,289	$22,258	$17,350

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 ("excess cost"). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. The excess cost amounts related to Promix, La Porte and Nemo are attributable to the tangible plant and pipeline assets of each entity, and are amortized against equity earnings from these entities in a manner similar to depreciation. The excess cost of Dixie includes amounts attributable to both goodwill and tangible pipeline assets, with that portion assigned to the pipeline assets being amortized in a manner similar to depreciation. The goodwill inherent in Dixie's excess cost is subject to periodic impairment testing and is not amortized. The following table summarizes our excess cost information:

	Initial Excess Cost	Unamortized balance at September 30, 2002	Unamortized balance at December 31, 2001	Amortization Charged to Equity Earnings during 2002	Amortization Period
Fractionation segment:					
Promix	$7,955	$6,695	$7,083	$298	20 years
La Porte	873	844	n/a	29	35 years
Pipelines segment:					
Dixie					
Attributable to pipeline assets	28,448	26,277	26,887	610	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,130	12,404	274	35 years
Nemo	727	703	718	16	35 years

The following tables present summarized income statement information for our unconsolidated investments accounted for under the equity method (for the periods indicated on a 100% basis).

Summarized Income Statement Data for the Three Months Ended

	September 30, 2002			September 30, 2001		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Pipelines	$ 79,903	$12,379	$10,277	$ 77,884	$16,843	$13,556
Fractionation	21,180	6,874	6,842	19,363	6,213	6,283
Octane Enhancement	61,501	3,393	3,466	54,955	2,060	2,725
Total	$162,584	$22,646	$20,585	$152,202	$25,116	$22,564

Summarized Income Statement Data for the Nine Months Ended

	September 30, 2002			September 30, 2002		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Pipelines	$210,789	$36,569	$29,987	$187,197	$37,134	$28,854
Fractionation	60,360	18,719	18,686	55,364	13,633	13,944
Octane Enhancement	167,562	20,940	21,113	168,873	17,982	18,932
Total	$438,711	$76,228	$69,786	$411,434	$68,749	$61,730

Uncertainties regarding our investment in BEF

We have a 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. MTBE has come under scrutiny by various governmental agencies and environmental groups over the last few years because underground storage tanks filled with motor gasoline containing MTBE have leaked contaminating water supplies. Certain states, primarily California, have moved to ban or reduce MTBE use due to these concerns. The California ban takes effect during the first quarter of 2004. In addition, the U.S. Senate, in April

2002, passed an energy bill that includes a total ban on the use of MTBE, which if ultimately adopted would be effective in four years. The Senate bill is now in a conference committee with the U.S. House of Representatives for resolution. The U.S. House of Representatives energy bill, which passed in August 2001, contains no such ban. We can give no assurance as to whether the federal government or individual states will ultimately adopt legislation banning the use of MTBE.

In April 2002, a jury in California found three energy companies liable for polluting Lake Tahoe's drinking water with MTBE. While this decision sets no legal precedent, this was the first time that a jury has defined gasoline containing MTBE to be a "defective product". This development has no direct impact on BEF since our customer uses the MTBE we produce in its eastern U.S. operations.

In light of these developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently leaning towards a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical quality of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of the first quarter of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

6. RECENTLY ISSUED ACCOUNTING STANDARDS AFFECTING US

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interests method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001.

There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 was effective for our fiscal year that began January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized.

At December 31, 2001, our intangible assets were comprised of the values associated with the Shell natural gas processing agreement and the goodwill related to the 1999 MBA acquisition. In accordance with SFAS No. 141, we reclassified the MBA goodwill to a separate line item on our consolidated balance sheet apart from the Shell contract. The value of the Shell natural gas processing agreement will continue to be amortized over its remaining contract term of approximately 18 years; however, amortization of the MBA goodwill will cease. The MBA goodwill will be subject to periodic impairment testing in accordance with SFAS No. 142 due to its indefinite life. For additional information regarding our intangible assets and goodwill (including significant additions to both classes of assets as a result of the Diamond-Koch acquisitions), see Note 7.

In accordance with the transition provisions of SFAS No. 142, we have completed an impairment review of the December 31, 2001 MBA goodwill balance. Professionals in the business valuation industry were consulted regarding the assumptions and techniques used in our analysis. As a result of this review, no impairment loss was indicated. Any subsequent impairment losses stemming from future goodwill impairment studies will be reflected as a component of operating income in the Statements of Consolidated Operations.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In April 2002, the FASB issued SFAS No. 145, "Rescission of SFAS Statements No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." The purpose of this statement is to update, clarify and simplify existing accounting standards. We adopted this statement effective April 30, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our intangible assets at September 30, 2002 and December 31, 2001:

		At September 30, 2002		At December 31, 2001	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$206,331	$(20,252)	$186,079	$(11,962)	$194,369
Mont Belvieu Storage II contracts	8,127	(174)	7,953		
Mont Belvieu Splitter III contracts	53,000	(1,010)	51,990		
Toca-Western natural gas processing contracts	11,096	(185)	10,911		
Toca-Western NGL fractionation contracts	20,041	(334)	19,707		
Venice contracts (a)	4,639		4,639		
MBA acquisition goodwill (b)	8,979			(1,122)	7,857

Total	$312,213	$(21,955)	$281,279	$(13,084)	$202,226

Notes:
(a) Amortization scheduled to begin when contracted-volumes begin to be processed in 2003.
(b) Amount reclassified to Goodwill on January 1, 2002 per transition provisions of SFAS 142.

At September 30, 2002, our intangible assets consisted of:

- the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999;
- certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002;
- certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002; and
- certain NGL-related contracts (the "Venice contracts") we acquired during the third quarter of 2002.

Our recorded intangible assets are comprised of the estimated values assigned to contract rights we own arising from agreements with customers. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of the entity. It is based on an analysis of all pertinent factors including (a) the expected use of the asset by the entity, (b) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (c) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause substantial costs or modifications to existing agreements, (d) the effects of obsolescence, demand, competition, and other economic factors and (e) the level of maintenance required to obtain the expected future cash flows.

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The approach to the valuation of each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

The following table shows amortization expense associated with our intangible assets for the three and nine months ended September 30, 2002 and 2001:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Shell natural gas processing agreement	$2,763	$2,222	$8,290	$4,497
Mont Belvieu Storage II contracts	58		174	
Mont Belvieu Splitter III contracts	379		1,010	
Toca-Western natural gas processing contracts	185		185	
Toca-Western NGL fractionation contracts	334		334	
MBA acquisition goodwill (a)		112		337
Total	$3,719	$2,334	$9,993	$4,834

Notes:
(a) Effective January 1, 2002, goodwill is no longer subject to amortization under SFAS 142 guidelines.

The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term (currently $11.1 million annually from 2002 through 2019). The values of the propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized over the expected 20-year remaining life of the assets to which they relate.

The initial $4.6 million value of the Venice contracts will be amortized over 14 years beginning in the third quarter of 2003. The value of these contracts will increase to $6.6 million during the third quarter of 2003 when a counterparty to one of the contracts completes certain pipeline modifications.

For 2002, amortization expense attributable to intangible assets is currently estimated at $13.7 million. Based on information currently available, we expect that amortization expense relating to existing intangibles will increase to $14.8 million during each of the years 2003 through 2007.

Goodwill

At September 30, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (values as of September 30, 2002):

- $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,
- $7.9 million related to the July 1999 purchase of an additional ownership interest in MBA, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

At December 31, 2001, the goodwill associated with the MBA acquisition was recorded as part of our intangible assets.

Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized but will be annually assessed for recoverability. In addition, we will periodically review the reporting units to which the goodwill amounts relate if impairment indicators are evident. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, will be calculated and compared to its combined book value. Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment.

If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value.

Pro Forma impact of discontinuation of amortization of goodwill

The following table discloses the unaudited pro forma impact on earnings of discontinuing amortization of the MBA goodwill for the periods indicated:

	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2001
Reported net income	$75,957	$222,266
Discontinue goodwill amortization	111	333
Adjusted net income	$76,068	$222,599

8. DEBT OBLIGATIONS

Our debt consisted of the following at:

	September 30, 2002	December 31, 2001
Borrowings under:		
364-Day Term Loan, variable-rate, $150 million due December 2002, $450 million due March 2003 and $600 million due July 2003	$1,200,000	
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	$450,000
Senior Notes A, 8.25% fixed-rate, due March 2005	350,000	350,000
Multi-Year Revolving Credit facility, variable-rate, due November 2005	240,000	
364-Day Revolving Credit facility, variable-rate, due November 2003 (see Note 13)	173,000	
MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed-rate, $15 million due each December, 2002 through 2005	60,000	
Total principal amount	2,527,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,834	1,653
Less unamortized discount on:		
Senior Notes A	(90)	(117)
Senior Notes B	(237)	(258)
Less current maturities of debt	(1,215,000)	
Long-term debt	$1,313,507	$855,278

364-Day Term Loan and Seminole Notes

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day variable-rate term loan to fund the acquisition of Mid-America and Seminole from Williams on July 31, 2002. The term loan will generally bear interest at either (as defined within the loan agreement):

|X| the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent; or
|X| a Eurodollar Rate, with any rate in effect being increased by an appropriate applicable margin.

For the period in which this debt was outstanding, the weighted-average interest rate charged was 3.41%. We applied approximately $180 million in proceeds from our Limited Partner's October 2002 equity offering to partially repay this Term Loan (see Note 13).

Seminole Notes. On July 31, 2002, Seminole had $60 million in 6.67% fixed-rate senior unsecured notes outstanding. The notes amortize by $15 million each December 1 through 2005. In accordance with generally accepted accounting principles, this debt is consolidated on our balance sheet because of our 78.4% ownership interest in Seminole.

Significant amendments to Multi-Year and 364-Day Revolving Credit facilities

The following significant amendments to the Multi-Year and 364-Day Revolving Credit facilities have been made during 2002:

|X| In April 2002, our total borrowing capacity under these two facilities was increased to $500 million, of which $87 million was outstanding at September 30, 2002. The amount that we can borrow under the Multi-Year Revolving Credit facility was increased by $20 million to $270 million. Likewise, the amount that we can borrow under the 364-Day Revolving Credit facility was increased by $80 million to $230 million.

|X| In April 2002, our debt covenants under these facilities were amended to allow us to exclude up to $50.0 million in commodity hedging losses we incurred during the first four months of 2002 from the calculation of Consolidated EBITDA (as defined in the revolving credit agreements). The amendment also increased the ratio of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities for certain periods.

|X| In July 2002, we amended our Multi-Year and 364-Day Revolving Credit facility to allow us to incur additional indebtedness fro the interim financing of the Mid-America and Seminole pipeline systems. This amendment provided for an increase in the amount of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities. In addition, the negative covenant on Indebtedness (as defined in the revolving credit agreements) was amended to permit the Seminole Notes.

See Note 13 for description of an amendment executed in November 2002 whereby the maturity of the 364-Day Revolving Credit agreement was extended from November 15, 2002 to November 14, 2003.

During the first nine months of 2002, the range of interest rates paid on the Multi-Year and 364-Day Revolving Credit facilities was 2.32% to 2.59%. The weighted-average interest rates paid on Multi-Year and 364-Day Revolving Credit facilities during the period was 2.31% and 2.46%, respectively.

Guarantor relationships

Enterprise Products Partners L.P. acts as guarantor of certain of the Operating Partnership's debt obligations. This parent-subsidiary guaranty provision exists under our 364-Day Term Loan; Senior Notes A and B; MBFC Loan; and the Multi-Year and 364-Day Revolving Credit facilities.

Letters of Credit

At September 30, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility of which $2.4 million was outstanding.

Other

The indentures under which Senior Notes A and B and the MBFC Loan were issued contain various restrictive covenants. We were in compliance with these covenants at September 30, 2002.

The 364-Day Term Loan, Multi-Year Revolving Credit facility, and 364-Day Revolving Credit facility contain various affirmative and negative covenants applicable to the Operating Partnership. The covenants of the 364-Day Term Loan are similar to those required under the Multi-Year and 364-Day Revolving Credit facilities. As such, the 364-Day Term Loan agreement contains covenants related to our ability to incur certain indebtedness, grant certain liens, enter into certain merger or consolidation transactions, and make certain investments. In addition, the 364-Day Term Loan requires us to satisfy certain financial covenants at the end of each fiscal quarter. We were in compliance with the covenants of these three debt agreements at September 30, 2002.

The Seminole Note agreements contain various restrictive covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at September 30, 2002.

9. CAPITAL STRUCTURE

Parent's Units acquired by Trust

During the first quarter of 1999, we established the EPOLP 1999 Grantor Trust (the "Trust") to fund potential future obligations under EPCO's long-term incentive plan (through the exercise of Common Unit options granted to directors of the General Partner and EPCO employees who participate in our business). The Common Units of our parent purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. At September 30, 2002, the Trust held 427,200 Common Units. The Trust purchased 100,000 Common Units during the first nine months of 2002 at a cost of $2.4 million.

The Trust is a party to our parent's Unit Buy-Back Program under which the Trust and our parent can repurchase up to 2.0 million Common Units. The Common Unit purchases made during the first nine months of 2002 were under this program. At September 30, 2002, an additional 618,400 Common Units could be repurchased under this program by the Trust or our parent separately or in combination. Purchases made by our parent will be funded by intercompany loans between us and our parent that will be settled on a quarterly basis.

The Unit totals noted above reflect a two-for-one split of our Parent's Units that occurred in May 2002.

Comprehensive Income

We report comprehensive income or loss in our Statements of Consolidated Partners' Equity and Comprehensive Income. For the nine months ended September 30, 2001, the cumulative transition adjustment resulting from the adoption of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted, was the only item of other comprehensive income for us and reduced Comprehensive Income by $2.3 million.

10. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows:

	Nine Months Ended September 30,	
	2002	2001
(Increase) decrease in:		
Accounts and notes receivable	$(50,948)	$ 151,246
Inventories	(144,746)	(44,755)
Prepaid and other current assets	16,183	(8,732)
Other assets	(3,326)	(121)
Increase (decrease) in:		
Accounts payable	50,393	(79,424)
Accrued gas payable	170,407	(153,039)
Accrued expenses	(5,657)	(5,818)
Accrued interest	(9,478)	
Other current liabilities	372	22,850
Other liabilities	(145)	124
Net effect of changes in operating accounts	$ 23,055	$(117,669)

During the first nine months of 2002, we completed $1.6 billion in business acquisitions of which the purchase price allocations of each affected various balance sheet accounts. See Note 2 for information regarding the allocation of the purchase price for these acquisitions.

We record various financial instruments relating to commodity positions and interest rate swaps at their respective fair values using mark-to-market accounting. For the nine months ended September 30, 2002, we recognized a net $12.8 million in non-cash mark-to-market losses related to decreases in the fair value of these financial instruments, primarily in our commodity financial instruments portfolio. For the nine months ended September 30, 2001, we recognized a net $39.4 million in non-cash mark-to-market income from our financial instruments portfolio.

During the third quarter of 2002, we made the first of two cash payments to acquire certain processing-related contract rights connected to the Venice gas processing facility. Of the initial $4.6 million value of this intangible asset group, $2.6 million was reclassified from construction-in-progress and $2.0 million represented the actual cash payment made to the third-party. The amount spent on construction-in-progress was reclassified due to the direct linkage between the capital expenditures made and the successful negotiation of the Venice contracts. The remaining $2.0 million is scheduled to be paid during the third quarter of 2003.

Cash and cash equivalents at September 30, 2002, per the Statements of Consolidated Cash Flows, excludes $7.3 million of restricted cash. This restricted cash represents amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the NYMEX exchange.

11. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in our Processing segment. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Commodity financial instruments

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities (or hedging strategies) is to hedge exposure to price risks associated with natural gas, NGL inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in our Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price we charge certain of our customers for natural gas.

We have adopted a financial commodity and commercial policy to manage our exposure to the risks of our natural gas and NGL businesses. The objective of these policies is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. Under these policies, we enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than one month) and long-term basis, generally not to exceed 24 months. The General Partner oversees our hedging strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policies (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policies.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. When financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these ineffective instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices.

We recognized a loss of $52.3 million in the first nine months of 2002 from our commodity hedging activities, of which $45.1 million was attributable to the first quarter of 2002. These losses are treated as an increase in operating costs and expenses in our Statements of Consolidated Operations. Of this amount, $41.7 million has been realized (e.g., paid out to counterparties). The remaining $10.6 million represents the negative change in value of the open positions between December 31, 2001 and September 30, 2002 (based on market prices at those dates). The market value of our open positions at September 30, 2002 was $2.7 million payable (a loss).

For the first nine months of 2001, we recognized income of $118.6 million from these activities of which $5.6 million was recorded in the first quarter; $64.7 million in the second quarter; and $48.3 million in the third quarter. Of the $118.6 million in commodity hedging income recorded during the first nine months of 2001, $34.6 million was attributable to the market value of open positions at September 30, 2001.

Interest rate swaps

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the Company's Senior Notes and MBFC Loan. We manage a portion of our exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding interest rate swaps is to manage debt service costs by converting a portion of fixed-rate debt into variable-rate debt or a portion of variable-rate debt into fixed-rate debt. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount.

The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements. At December 31, 2001 and September 30, 2002, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010. Under this agreement, we exchanged a fixed-rate of 8.70% for a market-based variable-rate. If it elects to do so, the counterparty may terminate this swap in March 2003.

We recognized income of $0.8 million during the first nine months of 2002 from our interest rate swap that is treated as a reduction of interest expense (with $0.1 million recorded in the third quarter of 2002). The market value of the interest rate swap at September 30, 2002 was $1.6 million. During the first nine months of 2001, we were party to several interest rate swaps having a variety of terms and notional amounts. We recognized $13.2 million in income from these instruments during the first nine months of 2001.

12. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

We have five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. The 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 Chief Executive Officer of the General Partner. Pipelines consists of both liquids and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Processing includes the natural gas processing business and its related merchant activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and other plant support functions.

We evaluate segment performance based on gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

Gross operating margin by segment includes intersegment and intrasegment revenues (offset by corresponding intersegment and intrasegment expenses within the segments), which are generally based on transactions made at market-related rates. Our intersegment and intrasegment activities include, but are not limited to, the following types of transactions:

- o NGL fractionation revenues from separating our NGL raw-make inventories into distinct NGL products using our fractionation plants for our merchant activities group (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);
- o liquids pipeline revenues from transporting our merchant volumes from the gas processing plants on our pipelines to our NGL fractionation facilities (an intersegment revenue of Pipelines offset by an intersegment expense of Processing); and,
- o the sale of our NGL equity production extracted by our gas processing plants to our merchant activities group (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany (both intersegment and intrasegment) accounts and transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. Our equity investments with industry partners are a vital component of our business strategy and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. 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 example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our merchant businesses. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States.
Most of our plant-based operations are located primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. Our merchant businesses are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

A reconciliation of segment gross operating margin to consolidated income before provision for taxes and minority interest follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Total segment gross operating margin	$107,205	$110,849	$200,556	$314,997
Depreciation and amortization	(24,292)	(13,071)	(58,491)	(34,893)
Retained lease expense, net	(2,274)	(2,660)	(6,852)	(7,980)
(Gain) loss on sale of assets	6	4	(6)	391
Selling, general and administrative	(12,271)	(7,644)	(27,872)	(22,230)
Consolidated operating income	68,374	87,478	107,335	250,285
Interest expense	(30,689)	(12,610)	(68,234)	(35,928)
Interest income from unconsolidated affiliates	28		120	15
Dividend income from unconsolidated affiliates		392	2,196	2,024
Interest income-other	576	1,018	2,396	6,789
Other,net	74	(275)	(68)	(806)

Consolidated income before provision for taxes and minority interest	$ 38,363	$ 76,003	$ 43,745	$222,379

Information by operating 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 external customers:							
Three months ended Sept. 30, 2002	$179,781	$174,303	$588,828		$401		$943,313
Three months ended Sept. 30, 2001	75,842	127,687	519,165		635		723,329
Nine months ended Sept. 30, 2002	458,548	411,973	1,519,803		1,300		2,391,624
Nine months ended Sept. 30, 2001	252,087	313,832	1,951,176		1,946		2,519,041
Intersegment and intrasegment revenues:							
Three months ended Sept. 30, 2002	59,737	27,469	123,049		100	$(210,355)	
Three months ended Sept. 30, 2001	41,273	22,464	244,145		99	(307,981)	
Nine months ended Sept. 30, 2002	149,237	77,557	390,278		302	(617,374)	
Nine months ended Sept. 30, 2001	127,058	67,874	486,111		290	(681,333)	
Equity income in unconsolidated affiliates:							
Three months ended Sept. 30, 2002	2,102	2,705		$1,156			5,963
Three months ended Sept. 30, 2001	1,948	3,432		909			6,289
Nine months ended Sept. 30, 2002	5,714	9,506		7,038			22,258
Nine months ended Sept. 30, 2001	4,201	6,838		6,311			17,350
Total revenues:							
Three months ended Sept. 30, 2002	241,620	204,477	711,877	1,156	501	(210,355)	949,276
Three months ended Sept. 30, 2001	119,063	153,583	763,310	909	734	(307,981)	729,618
Nine months ended Sept. 30, 2002	613,499	499,036	1,910,081	7,038	1,602	(617,374)	2,413,882
Nine months ended Sept. 30, 2001	383,346	388,544	2,437,287	6,311	2,236	(681,333)	2,536,391
Total gross operating margin by segment:							
Three months ended Sept. 30, 2002	34,585	63,887	8,417	1,156	(840)		107,205
Three months ended Sept. 30, 2001	35,189	22,415	52,026	909	310		110,849
Nine months ended Sept. 30, 2002	92,815	128,745	(26,141)	7,038	(1,901)		200,556
Nine months ended Sept. 30, 2001	93,660	65,234	148,536	6,311	1,256		314,997
Segment assets:							
At September 30, 2002	437,362	2,198,230	137,699		9,491	40,467	2,823,249
At December 31, 2001	357,122	717,348	124,555		8,921	98,844	1,306,790
Investments in and advances to unconsolidated affiliates:							
At September 30, 2002	97,952	212,834	33,000	57,302			401,088
At December 31, 2001	93,329	216,029	33,000	55,843			398,201
Intangible Assets:							
At September 30, 2002	71,697	7,953	201,629				281,279
At December 31, 2001	7,857		194,369				202,226
Goodwill:							
At September 30, 2002	81,547						81,547

Consolidated revenues for the third quarter of 2002 increased $219.7 million over those of the third quarter of 2001. The increase is primarily due to businesses we have acquired during 2002 such as Splitter III, Mid-America and Seminole (see Note 2). Consolidated revenues for the first nine months of 2002 decreased $122.5 million from those recorded during the same period in 2001. The decrease in year-to-date revenues is primarily due to lower NGL prices which negatively affected Processing revenues offset by the positive effect of revenues from businesses acquired during 2002.

Gross operating margin for the third quarter of 2002 decreased $3.6 million compared to the third quarter of 2001. The decrease was primarily due to a $43.6 million decline in gross operating margin from Processing offset by a $41.5 million increase in margin from our Pipelines segment. The quarter-to-quarter gross operating margin variance in Processing is primarily

attributable to a $49.7 million negative change in commodity hedging results between the periods: the 2001 period includes $48.3 million of income from these activities whereas the 2002 period includes a loss of $1.4 million. The $41.5 million positive change in gross operating margin from the Pipelines segment is primarily due to the acquisition of Mid-America and Seminole (which added $30.1 million in gross operating margin to our third quarter of 2002 results) and increased earnings from our Mont Belvieu storage facilities (including those we acquired in January 2002 from Diamond-Koch).

Gross operating margin for the nine months ended September 30, 2002 decreased $114.4 million compared to the same period during 2001. The decrease in year-to-date gross operating margin is principally due to a $174.7 million decrease in our Processing segment offset by a $63.5 million increase from our Pipelines segment. The largest contributing factor to the decline in Processing was a $170.9 million negative change in commodity hedging results between the periods. We recorded $118.6 million in income from certain natural-gas based commodity hedging strategies during the first nine months of 2001. These strategies did not perform as anticipated during the first quarter of 2002, leading us to exit many of these strategies. We recorded a loss of $52.3 million from our commodity hedging activities during the first nine months of 2002, of which $45.1 million was recognized during the first quarter, $5.8 million during the second quarter and $1.4 million during the third quarter. The increase in earnings from our

Pipelines segment is primarily due to the positive effect of businesses we have acquired over the last two years (Mid-America, Seminole, Acadian Gas and Mont Belvieu storage operations).

Since January 1, 2002, segment assets have increased $1.5 billion primarily due to acquisitions completed during the year (see Note 2). Intangible assets increased $79.1 million since January 1, 2002 primarily the result of the contract-based intangible assets we acquired from Diamond-Koch and Toca-Western (see Note 7). Goodwill was $81.5 million at September 30, 2002 due to the goodwill we added as a result of the Diamond-Koch acquisition and the reclassification of the goodwill associated with the 1999 MBA acquisition (see Note 7).

13. SUBSEQUENT EVENTS

Limited Partner contribution in October 2002

On October 3, 2002, our Limited Partner completed a public offering of 9.8 million Common Units. The Common Units were priced at $18.99 per Unit, based on the closing price of its Common Units on the NYSE on October 2, 2002. The net proceeds from the offering of approximately $180 million were contributed to us by the Limited Partner and were used to repay a portion of the debt we incurred to finance the Mid-America and Seminole acquisitions. The application of these proceeds met the payment required under the 364-Day Term Loan scheduled for December 2002.

Amendment of 364-Day Revolving Credit Agreement

On October 28, 2002, we completed an amendment which refinanced our 364-Day Revolving Credit facility. The amendment, which has an effective date of November 15, 2002, extends the maturity of the current unsecured 364-Day Revolving Credit facility from November 15, 2002 to November 14, 2003.

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

For the interim periods ended September 30, 2002 and 2001.

Enterprise Products Partners L.P. is a publicly-traded master 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 in Part I of this report on Form 10-Q.

CEO and CFO certification of our SEC filings

As a result of new regulations, the CEO and CFO of our General Partner are required to submit various certificates to the SEC related to our filings. In June 2002, the SEC ordered that the CEO and CFO of certain publicly-traded companies file sworn written statements regarding recent filings that they had made with the SEC (Order 4-460). We filed these certificates in conjunction with our second quarter of 2002 Form 10-Q. The SEC also posted these certificates on its website, www.sec.gov.

In July 2002, the Sarbanes-Oxley Act was signed into law. This act requires ongoing certifications to be filed by a CEO and CFO in connection with certain periodic reports filed with the SEC. We file with the SEC, as correspondence to our periodic reports, the certificates required under Section 906 of the Sarbanes-Oxley Act. We have included the certificates required under Section 302 of the Sarbanes-Oxley Act as part of this Form 10-Q.

The various certificates completed by the CEO and CFO of our General Partner can be viewed on our website, www.epplp.com. For additional items required in response to the Sarbanes-Oxley Act, see Item 4 of this Form 10-Q.

General

Our Company was formed in April 1998 to acquire, own and operate substantially all of the natural gas liquid ("NGL") processing and distribution assets of Enterprise Products Company ("EPCO"). We are a leading North American midstream energy company that provides a wide range of services to producers and consumers of natural gas and NGLs. NGLs are used by the petrochemical and refining industries to produce plastics, motor gasoline and other industrial and consumer products and also are used as residential, agricultural and industrial fuels. Our asset platform in the Gulf Coast region, combined with our recently acquired Mid-America and Seminole pipeline systems, creates the only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America. Our services include the:

- gathering and transmission of raw natural gas from both onshore and offshore Gulf of Mexico developments;
- processing of raw natural gas into a marketable product that meets industry quality specifications by removing mixed NGLs and impurities;
- purchase of natural gas for delivery to our industrial, utility and municipal customers;
- transportation of mixed NGLs to fractionation facilities by pipeline;
- fractionation of mixed NGLs produced as by-products of crude oil refining and natural gas production into component NGL products: ethane, propane, isobutane, normal butane and natural gasoline;
- transportation of NGL products to end-users by pipeline, railcar and truck;

- import and export of NGL products and petrochemical products through our dock facilities;
- fractionation of refinery-sourced propane/propylene mix into high purity propylene, propane and mixed butane;
- transportation of high purity propylene to end-users by pipeline;
- storage of natural gas, mixed NGLs, NGL products and petrochemical products;
- conversion of normal butane to isobutane through the process of isomerization;
- production of high-octane additives for motor gasoline from isobutane; and
- sale of NGL and petrochemical products we produce and/or purchase for resale on a merchant basis.

Our General Partner, Enterprise Products GP, LLC, owns a 1.0% general partner interest in the Company and a 1.0101% general partner interest in the Operating Partnership. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008-1038 and our telephone number is 713-880-6500.

Cautionary Statement regarding Forward-Looking Information and Risk Factors

This quarterly report on Form 10-Q contains various forward-looking statements and information that are based on our beliefs and those of the General Partner, as well as assumptions made by and information currently available to us. When used in this document, words such as "anticipate", "project", "expect", "plan", "forecast", "intend", "could", "believe", "may", and similar expressions and statements regarding the plans and objectives of the Company for future operations, are intended to identify forward-looking statements. Although we and the General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor the General Partner can give any assurance that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those we anticipated, estimated, projected or expected.

An investment in our debt or equity securities involves a degree of risk. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- fluctuations in oil, natural gas and NGL prices and production due to weather and other natural and economic forces;
- competitive practices in the industries in which we compete;
- operational and systems risks;
- environmental liabilities that are not covered by indemnity or insurance;
- the impact of current and future laws and governmental regulations (including environmental regulations) affecting the midstream energy industry in general and our NGL, MTBE and natural gas operations in particular;
- the loss of a significant customer;
- the use of financial instruments to hedge commodity and other risks which prove to be economically ineffective; and
- the failure to complete one or more new projects on time or within budget.

The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. These factors include the level of domestic oil, natural gas and NGL production and development, the availability of imported oil and natural gas, actions taken by foreign oil and natural gas producing nations and companies, the availability of transportation systems with adequate capacity, the availability of competitive fuels and products, fluctuating and seasonal demand for oil, natural gas and NGLs, and conservation and the extent of governmental regulation of production and the overall economic environment.

In addition we must obtain access to new natural gas volumes for our processing business in order to maintain or increase gas plant throughput levels to offset natural declines in field reserves. The number of wells drilled by third parties to obtain new volumes will depend on, among other factors, the price of gas and oil, the energy policy of the federal government and the availability of foreign oil and gas, none of which is in our control.

The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing and in the production of motor gasoline and as fuel for residential and commercial heating. A reduction in demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, governmental regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could have a negative impact on our results of operation. A material decrease in natural gas production or crude oil refining, as a result of depressed commodity prices or otherwise, or a decrease in imports of mixed butanes, could result in a decline in volumes processed and sold by us.

We have incurred significant additional indebtedness to finance the Mid-America and Seminole acquisitions, which may restrict our future financial and operating flexibility. 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. Debt service obligations, restrictive covenants and maturities resulting from this leverage may effect our ability to finance future operations, pursue acquisitions, fund other capital needs and pay distributions to Unitholders, and may make our results of operations more susceptible to adverse economic or operating conditions.

We currently expect to meet our anticipated future cash requirements, including scheduled debt repayments, through operating cash flow, and the proceeds of one or more future equity and debt offerings. However, our ability to access the capital markets for future offerings may be limited by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties which are difficult to predict and beyond our control. If we were unable to access the capital markets for future offerings, we might be forced to seek extensions for some of our short-term maturities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit could be more onerous than those contained in our existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility.

Our expectations regarding future capital expenditures are only forecasts regarding these matters. These forecasts may be substantially different from actual results due to various uncertainties including the following key factors: (a) the accuracy of our estimates regarding capital spending requirements, (b) the occurrence of any unanticipated acquisition opportunities, (c) the need to replace unanticipated losses in capital assets, (d) changes in our strategic direction and (e) unanticipated legal, regulatory and contractual impediments with regards to our construction projects.

Lastly, terrorists attacks aimed at our facilities could adversely affect our business. Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have an effect on our business.

For a description of the tax and other risks of owning our Common Units or the Operating Partnership's debt securities, see our registration documents (together with any amendments or supplements thereto) filed with the SEC on Forms S-1 and S-3. Our SEC File number is 1-14323 and our Operating Partnership's SEC File number is 333-93239-01.

Recent acquisitions and other investments

Acquisitions of Mid-America and Seminole Pipeline Systems. On July 31, 2002, we completed the acquisition of the Mid-America and Seminole pipeline systems from Williams for approximately $1.2 billion in cash. The acquisition included:

- the purchase of a 98% ownership interest in Mapletree, LLC, which owns 100% of the Mid-America pipeline system and indirectly owns 16 propane terminals and over 1.5 million barrels of storage capacity; and
- the purchase of a 98% ownership interest in E-Oaktree, LLC, which owns an 80% equity interest in the Seminole pipeline system.

Mid-America is a 7,226-mile NGL pipeline system connecting the Hobbs hub located on the Texas-New Mexico border with supply regions in the Rocky Mountains and with supply regions and markets in the Midwest. The Mid-America pipeline system is comprised of three major segments: the Conway North pipeline, the Conway South pipeline and the Rocky Mountain pipeline. Seminole is a 1,281-mile pipeline system that interconnects with the Mid-America pipeline system and transports mixed NGLs and NGL products from the Hobbs hub and the Permian basin to Mont Belvieu, Texas. Major customers utilizing the Mid-America and Seminole pipeline systems include BP, Burlington, ConocoPhillips, Duke, Equistar and Williams.

The acquisition of the Mid-America and Seminole pipeline systems significantly enhances our existing asset base by:

- accessing NGL-rich natural gas production in major North American natural gas producing regions;
- expanding our integrated natural gas and NGL network;
- providing access to new end markets for NGL products; and
- increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. In addition to access to supply, the combination of these assets with our existing assets creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States, and provides additional access to new end markets for NGL products. The Conway South segment of the Mid-America pipeline system connects the Conway hub with refineries in Kansas and transports mixed NGLs from Conway to Hobbs and from Hobbs to Mont Belvieu. The 2,740-mile Conway North pipeline links the market hub in Conway with petrochemical and refining customers and propane markets in the upper Midwest.

The funding of these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"). Our plans for permanent financing of these acquisitions include the issuance of equity and debt in amounts which are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet. The post-closing purchase price adjustments are expected to be completed during the fourth quarter of 2002. These acquisitions did not require any material governmental approvals.

Acquisition of Propylene Fractionation Business ("Splitter III"). In February 2002, we completed the purchase of various propylene fractionation assets and certain inventories of propylene and propane from Diamond-Koch for approximately $239 million in cash. The acquisition includes a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50% interest in a polymer grade propylene export terminal located in the Houston Ship Channel and varying interests in several supporting distribution pipelines and related equipment. This Mont Belvieu facility has the capacity to produce approximately 41 MBPD of polymer grade propylene.

Acquisition of Storage Business. In January 2002, we completed the purchase of various NGL and petrochemical storage assets from Diamond-Koch for approximately $130 million in cash. These storage facilities consist of 30 salt dome storage caverns located in Mont Belvieu, Texas with a useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed NGL products and olefins, such as ethylene and propylene. The facilities, together with our existing storage facilities, serve the largest concentration of petrochemical and refinery facilities in the United States, and represent the largest NGL and petrochemical underground storage operation in the world.

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. In September 2002, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. ChevronTexaco was required to sell its 12.5% interest in a consent order by the FTC as a condition of approving the merger between Chevron and Texaco. The effective date of the purchase was June 1, 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. Effective June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas

Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant.

Acquisition of NGL terminals from CornerStone Propane Partners, L.P. In November 2002, we purchased four NGL terminals, certain supply and sales contracts and existing propane inventories from an affiliate of CornerStone Propane Partners, L.P. for approximately $11.5 million. The terminals are located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama. The storage facilities related to these terminals will handle approximately 0.1 million barrels. The Bakersfield, Rocklin and Reno terminals support fee-based logistical services we provide to several west coast refiners, including Shell. As part of the agreement, we will acquire certain wholesale NGL supply and sales contracts that utilize the acquired terminals as well as those of the Mid-America pipeline system and the Dixie pipeline system. The effective date of the purchase was November 1, 2002.

For additional information regarding our acquisitions (including pro forma data), see Note 2 to our Unaudited Consolidated Financial Statements included elsewhere in this report on Form 10-Q.

Our 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 the 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 should the underlying assumptions prove to be incorrect. Examples of these estimates and assumptions include depreciation methods and estimated lives of property, plant and equipment, amortization methods and estimated lives of qualifying intangible assets, methods employed to measure the fair value of goodwill, revenue recognition policies and mark-to-market accounting procedures. The following describes the estimation risk in each of these significant financial statement items:

- *Property, plant and equipment.* Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Our plants, pipelines and storage facilities have estimated useful lives of five to 35 years. Our miscellaneous transportation equipment have estimated useful lives of three to 35 years. Depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being incurred evenly over the life of the asset. The determination of an asset's estimated useful life must take a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and 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 economic obsolescence, the business climate, legal or other factors, we would review the asset for impairment and record any necessary reduction in the asset's value as a charge against earnings. At September 30, 2002 and December 31, 2001, the net book value of our property, plant and equipment was $2.8 billion and $1.3 billion, respectively.

o *Intangible assets.* The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The approach to the valuation of each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our recorded intangible assets primarily include the estimated value assigned to certain contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of the entity. It is based on an analysis of all pertinent factors including (a) the expected use of the asset by the entity, (b) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (c) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause substantial costs or modifications to existing agreements, (d) the effects of obsolescence, demand, competition, and other economic factors and (e) the level of maintenance required to obtain the expected future cash flows.

At September 30, 2002, our significant intangible assets consisted of the following (along with unamortized balances of each group at that date):

o the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999 ($186.1 million);
o certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002 ($60.0 million); and
o certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002 ($30.6 million).

The Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term. The propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The Toca-Western NGL fractionation contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate. If the underlying assumptions governing the amortization of any of these intangible assets were later determined to have significantly changed or to be impaired, then we might need to reduce the amortization period of such asset to less than that currently being used. Such a change would increase the annual amortization charge at that time.

o *Goodwill.* At September 30, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is primarily comprised of the $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002. Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized. Instead, goodwill is tested at a reporting unit level annually, and more frequently, if certain circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, is calculated and compared to its combined book value. Currently, all of our goodwill is recorded as part of the Fractionation operating segment (based on the assets to which the goodwill relates).

If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value.

o *Revenue recognition.*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 might 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.
Of the contracts that we enter into with customers, the majority fall within five main categories as described below:

o Tolling (or throughput) arrangements where we process or transport customer volumes for a cash fee (usually on a per gallon or other unit of measurement basis);
o Merchant contracts where we sell products to customers at market-related prices for cash;
o Storage agreements where we store volumes or reserve storage capacity for customers for a cash fee; and

o Fee-based marketing services where we market volumes for customers for either a percentage of the final cash sales price or a cash fee per gallon handled.

A number of tolling (or throughput) arrangements are utilized in our Fractionation and Pipeline segments. Examples include NGL fractionation, isomerization and pipeline transportation agreements. Typically, we recognize revenue from tolling arrangements once contract services have been performed. At times, the tolling fees we or our affiliates charge for pipeline transportation services are regulated by such governmental agencies as the FERC. A special type of tolling arrangement, an "in-kind" contract, is utilized by various customers at our Norco and Toca Western NGL fractionation facilities. An in-kind processing contract allows us to retain a contractually-determined percentage of NGL products produced for the customer in lieu of a cash tolling fee per gallon. Revenue is recognized from these "in-kind" contracts when we sell (at market-related prices) and deliver the fractionated NGLs that we retained using merchant contracts.

Our Processing segment businesses employ tolling and merchant contracts. If a customer pays us a cash tolling fee for our natural gas processing services, we record revenue to the extent that natural gas volumes have been processed and sent back to the producer. If we retain mixed NGLs as our fee for natural gas processing services, we record revenue when the NGLs (in mixed and/or fractionated product form) are sold and delivered to customers using merchant contracts. In addition to the Processing segment, merchant contracts are utilized in the Fractionation segment to record revenues from the sale of propylene volumes and in the Pipelines segment to record revenues from the sale of natural gas. Our merchant contracts are generally based on market-related prices as determined by the individual agreements.

We have established an allowance for doubtful accounts to cover potential bad debts from customers. Our allowance amount is generally determined as a percentage of revenues for the last twelve months. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing financial uncertainties. We routinely review our estimates in this area to ascertain that we have recorded ample reserves to cover forecasted losses. If unanticipated financial difficulties were to occur with a significant customer or customers, there is the possibility that the allowance for doubtful accounts would need to be increased to bring the allowance up to an appropriate level based on the new information obtained. Our allowance for doubtful accounts was $21.0 million at September 30, 2002 and $20.6 million at December 31, 2001.

o *Fair value accounting for financial instruments.* Our earnings are also affected by use of the mark-to-market method of accounting required under GAAP 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. As of September 30, 2002, none of these financial instruments qualify for hedge accounting treatment and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. 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 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.

For the nine months ended September 30, 2002, we recognized losses from our commodity hedging activities of $52.3 million. Of this loss, $10.6 million is attributable to the negative change in market value of the commodity hedging portfolio since December 31, 2001 using the mark-to-market method of accounting for our financial instruments. For additional information regarding our use of financial instruments to manage risk and the earnings sensitivity of these instruments to changes in underlying commodity prices, see the Processing segment discussion under "Our results of operations" and Item 3 of this report.

Additional information regarding our financial statements and those of the Operating Partnership can be found in the Notes to Unaudited Consolidated Financial Statements of each entity included elsewhere in this report on Form 10-Q.

Our results of operations

Revenues, costs and expenses and operating income

The following table shows our consolidated revenues, costs and expenses, and operating income for the three and nine month periods ended September 30, 2002 and 2001 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Revenues	$949,276	$729,618	$2,413,882	$2,536,391
Costs and expenses	$880,920	$642,212	$2,306,666	$2,285,497
Operating income	$ 68,356	$ 87,406	$ 107,216	$ 250,894

Three months ended September 30, 2002 and 2001. Revenues for the third quarter of 2002 increased $219.7 million over those of the third quarter of 2001. The increase is primarily due to businesses we have acquired during 2002 such as Splitter III, Mid-America and Seminole. Costs and expenses increased $238.7 million quarter-to-quarter primarily due to (i) the addition of costs and expenses of acquired businesses and (ii) higher NGL and natural gas prices and (iii) a negative change in our commodity hedging activities which increased the costs of our merchant activities. Operating income fell $19.1 million quarter-to-quarter as a result of the aforementioned reasons.

In general, NGL prices approximated a weighted-average of 42 CPG during the third quarter of 2002 and 40 CPG during the third quarter of 2001. The price of natural gas averaged $3.16 per MMBtu during the 2002 quarter versus $2.90 per MMBtu during the 2001 quarter.

Nine months ended September 30, 2002 and 2001. Revenues for the first nine months of 2002 decreased $122.5 million from those recorded during the same period in 2001. The year-to-year decrease in revenues is primarily due to lower NGL prices which reduced revenues from our merchant activities offset by the positive effect of revenues from businesses acquired during 2002. Costs and expenses for the nine months ended September 30, 2002 increased $21.2 million when compared to the same period in 2001. The year-to-year increase is primarily due to the addition of costs and expenses of acquired businesses offset by a decrease in NGL and natural gas prices (which affected energy-related expenses at our facilities and the costs of our merchant activities). As a result of the change in revenues and costs and expenses between the two periods, operating income decreased $143.7 million. In general, NGL prices approximated a weighted-average of 36 CPG during the first nine months of 2002 compared to 50 CPG during the same period in 2001. The price of natural gas averaged $2.86 per MMBtu during the 2002 period versus $4.87 per MMBtu during the 2001 period.

The following table illustrates selected average quarterly prices for natural gas, crude oil, selected NGL products and polymer grade propylene since January 2001:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Polymer Grade Propylene, $/pound
	(a)	(b)	(a)	(a)	(a)	(a)	(a)
Fiscal 2001:							
First quarter (c)	$7.05	$28.77	$0.49	$0.63	$0.70	$0.74	$0.23
Second quarter	$4.65	$27.86	$0.37	$0.50	$0.56	$0.66	$0.19
Third quarter	$2.90	$26.64	$0.27	$0.41	$0.49	$0.49	$0.16
Fourth quarter	$2.43	$21.04	$0.21	$0.34	$0.40	$0.39	$0.18
Fiscal 2002:							
First quarter	$2.34	$21.41	$0.22	$0.30	$0.38	$0.44	$0.16
Second quarter	$3.38	$26.26	$0.26	$0.40	$0.48	$0.51	$0.20

Third quarter	$3.16	$28.30	$0.26	$0.42	$0.52	$0.58	$0.21

(a) Natural gas, NGL and polymer grade propylene prices represent an average of index prices
(b) Crude Oil price is representative of West Texas Intermediate
(c) Natural gas prices peaked at approximately $10 per MMBtu in January 2001

Gross operating margin. Our management evaluates segment performance based on gross operating margin (or "margin"). Gross operating margin for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and selling, general and administrative expenses. Segment gross operating margin is exclusive of interest expense, interest income amounts, dividend income, minority interest, extraordinary charges and other income and expense transactions.

We have five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of liquids 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 merchant activities. Octane Enhancement represents our interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment primarily consists of fee-based marketing services.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. 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 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.

Our gross operating margin amounts by segment (in thousands of dollars) along with a reconciliation to consolidated operating income were as follows for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Gross Operating Margin by segment:				
Pipelines	$63,887	$22,415	$128,745	$ 65,234
Fractionation	34,585	35,189	92,815	93,660
Processing	8,417	52,026	(26,141)	148,536
Octane enhancement	1,156	909	7,038	6,311
Other	(840)	310	(1,901)	1,256
Gross Operating margin total	107,205	110,849	200,556	314,997
Depreciation and amortization	24,292	13,071	58,491	34,893
Retained lease expense, net	2,274	2,660	6,852	7,980
Loss (gain) on sale of assets	(6)	(4)	6	(391)
Selling, general and administrative expenses	12,289	7,716	27,991	21,621
Consolidated operating income	$68,356	$87,406	$107,216	$250,894

Our significant plant production and other volumetric data were as follows for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
MBPD, Net				
Major NGL and Petrochemical Pipelines	1,353	479	1,375	452
NGL Fractionation	247	224	233	198
Isomerization	88	81	82	82
Propylene Fractionation	55	34	55	31
Equity NGL Production	78	62	78	57
Octane Enhancement	5	5	5	4
MMBtu/D, Net				
Natural Gas Pipelines	1,250,241	1,426,463	1,258,364	1,342,104

The following discussions highlight the significant quarterly and year-to-date comparisons in gross operating margin and volumes by operating segment.

Pipelines

Our Pipelines segment consists of natural gas, NGL and petrochemical liquids transportation and distribution pipelines. Our natural gas pipeline systems provide for the gathering, transmission and storage of natural gas from both onshore and offshore Louisiana developments. Our liquids pipelines transport mixed NGLs and hydrocarbons to NGL fractionation plants and distribute NGL and petrochemical products to petrochemical plants, refineries and propane markets.

Three months ended September 30, 2002 and 2001. Our Pipelines segment posted a record $63.9 million in gross operating margin for the third quarter of 2002 compared to $22.4 million for the third quarter of 2001. Net pipeline volumes for the third quarter of 2002 were 1,682 MBPD compared to 854 MBPD for the same quarter during 2001. The Mid-America and Seminole pipeline systems (which we acquired on July 31, 2002) accounted for 868 MBPD of the increase in net pipeline volumes between the two periods. These volumes are on an energy equivalent basis where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Of the $41.5 million increase in margin quarter-to-quarter, $30.1 million is attributable to Mid-America and Seminole (which we acquired on July 31, 2002) and $6.5 million is attributable to an increase in earnings from our Mont Belvieu storage business. The primary reason for the increase in Mont Belvieu storage margins is the acquisition of storage assets from Diamond-Koch in January 2002. The remaining $4.9 million net increase in margin is attributable to increases in volumes transported or handled, decreases in operating expenses, and an increase in take-or-pay fees offset by a decrease in volumes inclusive of the effect of Tropical Storm Isidore on our other pipeline assets.

Tropical Storm Isidore came onshore in south Louisiana during the last week of September 2002. The storm negatively affected offshore natural gas production activities and onshore natural gas processing, NGL fractionation and pipeline operations. We estimate that the storm lowered earnings from our Gulf of Mexico natural gas pipelines by $0.2 million and from our NGL liquids pipelines by $0.1 million during the third quarter of 2002.

Nine months ended September 30, 2002 and 2001. From a year-to-date perspective, our Pipelines segment recognized $128.7 million in gross operating margin for the first nine months of 2002 compared to $65.2 million during the same period in 2001. Net pipeline volumes (on an energy equivalent basis) were 1,706 MBPD during the 2002 period versus 805 MBPD during the 2001 period. As in the quarter-to-quarter discussion above, the largest contributing factor in the growth of our pipeline margins is acquisitions. Of the $63.5 million increase in margin period-to-period, $30.1 million is attributable to Mid-America and Seminole and $14.8 million is attributable to an increase in earnings from our Mont Belvieu storage business. The primary reason for the increase in Mont Belvieu storage margins is the acquisition of storage assets from Diamond-Koch in January 2002. The remaining $18.6 million net increase in margin is attributable to increases in volumes transported or handled, decreases in operating expenses, and an increase in take-or-pay fees offset by a decrease in volumes inclusive of the effect of Tropical Storm Isidore on our other pipeline assets.

Fractionation

Our Fractionation segment includes eight NGL fractionators, an isomerization complex and four propylene fractionation facilities. NGL fractionators separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Our isomerization unit converts normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. In general, our propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane.

Three months ended September 30, 2002 and 2001. On a quarterly basis, gross operating margin was $34.6 million for the third quarter of 2002 compared to $35.2 million for the same period in 2001. NGL fractionation margin decreased $4.8 million for the third quarter of 2002 when compared to the third quarter of 2001. NGL fractionation net volumes improved to 247 MBPD during the 2002 period versus 224 MBPD during the 2001 period. The decrease in NGL fractionation margin is primarily due to lower tolling revenues at our Mont Belvieu NGL fractionator due to competition at this industry hub and lower volumes at our Norco facility partially offset by margins from our newly acquired Toca-Western NGL fractionator. Margins from our Louisiana-based NGL fractionators (Norco, Toca-Western, BRF, and Promix) were also affected by Tropical Storm Isidore in late September 2002. We estimate that the storm resulted in approximately $0.8 million in lost margins from these facilities during the third quarter of 2002.

Our isomerization business posted a $0.1 million increase in margin quarter-to-quarter with isomerization volumes increasing to 88 MBPD during the 2002 period from 81 MBPD during the 2001 period. The positive effect of the higher volumes was offset by an increase in expenses. For the third quarter of 2002, gross operating margin from propylene fractionation was $4.9 million higher than the third quarter of 2001 primarily due to margin from the propylene fractionation business (Splitter III) we acquired from Diamond-Koch in February 2002. Net volumes at our propylene fractionation facilities increased to 55 MBPD from 34 MBPD, primarily due to Splitter III.

Nine months ended September 30, 2002 and 2001. From a year-to-date perspective, Fractionation gross operating margin was $92.8 million for the first nine months of 2002 versus $93.7 million for the first nine months of 2001. NGL fractionation margin decreased $7.6 million during the 2002 period when compared to the 2001 period. NGL fractionation net volumes improved to 233 MBPD

during the first nine months of 2002 versus 198 MBPD for the same period in 2001. NGL fractionation volumes during the first quarter of 2001 were unusually low due to reduced NGL extraction rates at gas processing plants caused by abnormally high natural gas prices (which resulted in a decrease in mixed NGL volumes available for fractionation). The decrease in NGL fractionation margin for the 2002 period is primarily due to the following:

- certain non-routine maintenance charges at our Mont Belvieu facility in the first quarter of 2002;
- a decrease in tolling revenues at our Mont Belvieu facility due to competition at this industry hub offset by an increase in fractionation volumes);
- lower in-kind fee revenue at our Norco plant (caused by lower NGL prices in 2002 relative to 2001); offset by
- increased margins at other facilities due to higher processing volumes and the margins from our newly acquired Toca-Western NGL fractionator.

Our isomerization business posted a $9.0 million decrease in margin for the first nine months of 2002 when compared to the first nine months of 2001. Isomerization volumes were 82 MBPD during both periods. The decrease in margin is primarily due to lower isomerization revenues. Certain of our isomerization fees are indexed to historical natural gas prices and were positively impacted when the price of natural gas was at historically high levels during 2001, particularly during the first quarter of 2001.

For the first nine months of 2002, gross operating margin from propylene fractionation was $16.4 million higher than the same period in 2001 primarily due to $18.3 million in margin from Splitter III which we acquired in February 2002 from Diamond-Koch. Net volumes at our propylene fractionation facilities increased to 55 MBPD from 31 MBPD.

Processing

This segment is comprised of our natural gas processing business and related merchant activities. At the core of our natural gas processing business are twelve gas plants located primarily in south Louisiana. Our net share of the NGL production from these gas plants, Norco and Toca-Western (i.e., "our equity NGL production"), in addition to the NGLs we purchase on a merchant basis and a portion of the production from our isomerization facilities, support the merchant activities included in this operating segment.

Three months ended September 30, 2002 and 2001. For the third quarter of 2002, we posted a margin of $8.4 million compared to $52.0 million for the same period in 2001. Our equity NGL production for the third quarter of 2002 increased 16 MBPD over the same period in 2001 primarily due to improved gas processing economics. The change in margin between the two quarters is primarily due to a $49.7 million negative change in the results of our commodity hedging activities. We recorded a loss of $1.4 million from our commodity hedging activities during the third quarter of 2002 compared to income of $48.3 million during the third quarter of 2001. For further information regarding our commodity hedging losses, see "*Impact of commodity hedging activities on our results of operations*" in this Processing section. The decline in commodity hedging results was offset by a favorable decrease in NGL inventory valuation adjustments between the two quarters. We estimate that Tropical Storm Isidore lowered equity NGL production by 5 MBPD and gross operating margin by $0.8 million during the third quarter of 2002.

Nine months ended September 30, 2002 and 2001. Gross operating margin was a loss of $26.1 million for the first nine months of 2002 compared to income of $148.5 million for the first nine months of 2001. Our equity NGL production averaged 78 MBPD during the 2002 period versus 57 MBPD during the 2001 period. Equity NGL production during the 2001 period reflected reduced NGL extraction rates at our gas plants resulting from abnormally high natural gas prices (which negatively affected operating costs), particularly during the first quarter of 2001. Of the $174.7 million decrease in margin between the periods, the significant differences are as follows:

- We recorded a loss of $52.3 million from our commodity hedging activities during the first nine months of 2002, of which $45.1 million of the loss was recognized during the first quarter of 2002. This compares to $118.6 million of income from such activities during the first nine months of 2001. For further information regarding our commodity hedging losses, see "*Impact of commodity hedging activities on our results of operations*" in this Processing section.

- Prior year margin benefited from unusually strong demand for propane in the first quarter of 2001 for heating and isobutane in the second quarter of 2001 for refining.
- The decline in commodity hedging results and reduced demand for propane and isobutane was offset by a favorable decrease in NGL inventory valuation adjustments between the two periods and improved processing margins. Processing economics improved period-to-period as a result of lower natural gas prices during the 2002 period relative to the 2001 period which in turn resulted in higher equity NGL production rates during 2002.

Impact of commodity hedging activities on our results of operations. In order to manage the risks associated with our Processing segment, we may enter into short-term, highly liquid commodity financial instruments to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We have employed various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL and natural gas prices) on margins from our Processing segment.

Beginning in late 2000 and extending through March 2002, a large number of our hedging transactions were based on the historical relationship between natural gas prices and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed-price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL merchant activities and the value of our equity NGL production. Throughout 2001, this strategy proved very successful to us (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $105.6 million in income from commodity hedging activities we recorded during 2001.

In late March 2002, the effectiveness of this strategy deteriorated due to a rapid increase in natural gas prices whereby the loss in the value of fixed-price natural gas financial instruments was not offset by increased gas processing margins. Due to the inherent uncertainty that was controlling natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The failure of this strategy during 2002 is the primary reason for the $52.3 million in commodity hedging losses we recorded through September 30, 2002.

A variety of factors influence whether or not our hedging strategies are successful. For additional information regarding our commodity financial instruments, see Item 3 of this report on Form 10-Q.

Octane Enhancement

Our Octane Enhancement segment consists of a 33.33% equity investment in BEF, which owns a facility which currently produces motor gasoline additives to enhance octane.

Three months ended September 30, 2002 and 2001. Our third quarter of 2002 equity earnings from BEF increased $0.2 million when compared to the third quarter of 2001 primarily due to lower expenses. Our share of MTBE production from this facility was 5 MBPD.

Nine months ended September 30, 2002 and 2001. Equity earnings from our BEF investment improved to $7.0 million during the first nine months of 2002 from $6.3 million during the same period in 2001. The improvement is primarily due to an increase in MTBE production during the 2002 period (resulting from less maintenance downtime) offset by the impact of lower overall MTBE prices period-to-period which affected margins.

Other matters

Selling, general and administrative expenses. The increase in selling, general and administrative expenses on both a year-to-date and quarter-to-quarter basis is primarily attributable to businesses we have acquired during 2002.

Interest expense. Interest expense increased $18.1 million to $30.7 million during the third quarter of 2002 from $12.6 million during the third quarter of 2001. The quarter-to-quarter increase is primarily due to additional borrowings we have made in conjunction with acquisitions during 2002 and investments in inventories. Of the interest expense we recorded during the third quarter of 2002, $10.2 million is attributable to the debt used to finance the Mid-America and Seminole acquisition.

Interest expense increased $32.3 million to $68.2 million during the first nine months of 2002 from $35.9 million during the first nine months of 2001. The year-to-date increase is primarily attributable to debt incurred for business acquisitions and investments in inventory.

Income from our interest rate hedging activities (which is treated as a reduction in interest expense) decreased $3.7 million between the two quarters. For the nine months ended September 30, 2002 and 2001, income from interest rate hedging activities was $0.8 million and $11.3 million. The difference between the quarter-to-quarter and year-to-date periods is primarily due to certain elections by counterparties during 2001 and a decrease in interest rates.

General outlook for the Fourth Quarter of 2002 and First Quarter of 2003

Processing

Based on our current expectations of natural gas production from the Gulf of Mexico, operating conditions and NGL product and natural gas prices, we estimate that our equity NGL production rates will average 60 MBPD during the fourth quarter of 2002 and rise to 65 MBPD during the first quarter of 2003. Virtually all Gulf of Mexico natural gas production was impacted and experienced some downtime due to Tropical Storm Isidore and Hurricane Lili during September and October 2002. Including the effects on production before, during and after the storms, it is estimated that approximately 10 to 12 days of natural gas production were lost that would have been processed at our facilities. By mid-October 2002, it was estimated that nearly all of natural gas production in the Gulf of Mexico was back on line. We estimate that Tropical Storm Isidore lowered our equity NGL production rates by 5 MBPD during the third quarter of 2002 and that Hurricane Lili lowered equity NGL productions for the fourth quarter of 2002 by 7 MBPD. We currently estimate that Hurricane Lili lowered gross margin from our Processing segment by approximately $1.1 million during the fourth quarter of 2002.

Shell's "Manatee" Gulf of Mexico deepwater field began production late in the third quarter of 2002. In addition, we are expecting that their "Princess" Gulf of Mexico deepwater development will begin production late in the fourth quarter of 2002. Depending on processing economics (discussed below), the gas processed from these two new developments could add approximately up to 1 MBPD to our equity NGL production rate during the fourth quarter of 2002 and approximately 2.5 MBPD to the rate for the first quarter of 2003.

From a processing economics perspective, natural gas prices are expected to remain strong during the fourth quarter of 2002 and first quarter of 2003, which may negatively affect processing margins given anticipated NGL prices. As a result, some regional gas processing facilities (including a number of ours) may elect to reduce NGL recoveries. If gas prices moderate and NGL prices strengthen, processing economics would improve and may lead to higher NGL extraction rates at our facilities. At full NGL extraction rates, we expect that our equity NGL production rate would approximate 85 MBPD.

Pipelines

Many of our Gulf Coast-based pipeline operations were affected by Tropical Storm Isidore and Hurricane Lili in September and October 2002. We estimate that these storms lowered Pipelines gross margin by $0.8 million during the third quarter of 2002 and by $1.0 million during the fourth quarter of 2002. These estimates include the impact of lost throughput on both our natural gas and NGL pipeline systems in both onshore and offshore Louisiana. Our Mid-America and Seminole pipeline systems should perform as expected during the fourth quarter of 2002 and first quarter of 2003. We expect volumes on the Mid-America system to seasonally increase during the first quarter of 2003 in line with propane demand for heating in the midwestern U.S. We believe that consolidated gross operating margin (before minority interest) from these systems will approximate $45 million per quarter for both the fourth quarter of 2002 and first quarter of 2003 based upon current information. As for our Gulf Coast liquids pipelines, we expect that reduced NGL recoveries at gas processing facilities in the region may negatively affect the throughput rates on certain of our pipelines during the fourth quarter of 2002 and first quarter of 2003. We expect gross margin from the Dixie pipeline to increase during the fourth quarter of 2002 and first quarter of 2003 as seasonal heating requirements in the southeastern U.S. increase throughput on the system.

Our storage operations should continue to benefit as NGL production continues and slow petrochemical and other downstream demand for feedstocks keeps inventory levels higher than normal. Import volumes at our Houston Ship Channel import dock are expected to reflect seasonal lows while EPIK's export activity is projected to be near maximum rates over the next two quarters. EPIK usually experiences a seasonal increase in exports of propane during the winter months.

Apart from the effects of Hurricane Lili on fourth quarter of 2002 margins, we anticipate that volumes from our Gulf of Mexico and Acadian Gas natural gas pipeline businesses for the fourth quarter of 2002 and first quarter of 2003 will be consistent with historic levels adjusted for the effects of seasonality, peaking requirements of certain customers and variance from normal weather. Our Gulf of Mexico pipelines may be somewhat affected by natural declines in production offset by volumes from new wells.

Fractionation

Over the next two quarters, we anticipate that margins and volumes from our NGL fractionators may be somewhat affected by reduced NGL recoveries at gas processing plants. When natural gas plants are in these modes, the volumes sent by the gas plants to NGL fractionators for further processing are reduced. As we discussed earlier, we believe that ethane rejection or reduced NGL recoveries may occur at many gas processing facilities along the Gulf Coast, including some of our own based on current forecasts of natural gas and NGL prices. Ethane rejection could also occur at gas processing facilities in the Mid-Continent and Rocky Mountain regions of the country which may affect the volume of mixed NGLs delivered by the Seminole pipeline to our Mont Belvieu NGL fractionator for processing.

In addition, operating expenses are expected to rise during the same period as a result of higher energy costs at these facilities caused by the forecasted increase in natural gas prices. Gross margin from our Mont Belvieu NGL fractionator will continue showing weakness when compared to 2001 results due to the competition at this industry hub which has reduced tolling fees. The anticipated decreases in gross margin will be partially offset by the margins added by our newly acquired Toca-Western facility. We anticipate that net NGL fractionation volumes will range between 235 MBPD and 255 MBPD during the fourth quarter of 2002 and first quarter of 2003.

Our estimates are that Hurricane Lili reduced fourth quarter of 2002 margins from our Louisiana facilities by $0.9 million.

Production rates at our isomerization facilities are expected to average 78 MBPD during the fourth quarter of 2002 and 79 MBPD during the first quarter of 2003. The decline in volumes from the third quarter of 2002 rate is primarily due to the end of the gasoline blending season at refineries. We also expect a modest decline in demand for isomerization services during 2003 as refiners reduce their MTBE production in advance of California's ban on the oxygenate that takes effect January 1, 2004. This may be offset by demand for isomerization services to facilitate alkylate production.

We anticipate that demand for our propylene fractionation services and products will be comparative with that we experienced during the third quarter of 2002. Our propylene fractionation volumes are estimated to be 52 MBPD for the fourth quarter of 2002 and 55 MBPD for the first quarter of 2003.

Octane Enhancement

BEF should experience a seasonal decline in margins during the fourth quarter of 2002 as gasoline refiners scale down their demand for MTBE and during the first quarter of 2003 due to the scheduled annual maintenance at this facility. As a result of California's switch from using MTBE to ethanol in its clean fuels program in January 2004, we expect that MTBE margins will begin to weaken during 2003. Demand for BEF's MTBE production is governed by its contract with Sun, which purchases the MTBE primarily for use in its eastern U.S. gasoline markets.

Our liquidity and capital resources

As noted at the beginning of Item 2, 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 following discussion of liquidity and capital

resources constitutes combined (or consolidated) information for the two registrants. References to partnership equity securities in this discussion pertain to Units issued by Enterprise Products Partners L.P. References to public debt pertain to those obligations issued by Enterprise Products Operating L.P. and guaranteed by Enterprise Products Partners L.P.

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 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 bank credit facilities and the issuance of additional partnership equity and public debt. Our quarterly cash distributions to partners are expected to be funded primarily by current period 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 fair values 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 flows from operations are directly linked to earnings from our business activities. Like our results of operations, these cash flows are exposed to certain risks including fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing and in the production of motor gasoline and as fuel for residential 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 NGL products, increased competition from petroleum-based products due to pricing differences or other reasons, could have a negative impact on earnings and thus the availability of cash from operating activities. 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*".

As noted above, certain of our liquidity and capital resource requirements are met using borrowings under bank credit facilities and/or the issuance of additional partnership equity or public debt (separately or in combination). As of September 30, 2002, total borrowing capacity under our 364-Day and Multi-Year Revolving Credit facilities was $500 million of which $87 million was available.

Our plans for permanent financing of the approximately $1.2 billion Mid-America and Seminole acquisitions include the issuance of equity and debt in amounts that are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet. For additional information regarding our debt, see the section below labeled "*Our debt obligations*".

On February 23, 2001, we filed a $500 million universal shelf registration (the "February 2001 Shelf") covering the issuance of an unspecified amount of partnership equity or debt securities or a combination thereof. In October 2002, we used approximately $186 million of this shelf registration to complete a public offering of 9.8 million Common Units. The Common Units were priced at $18.99 per Unit, based on the closing price of our Common Units on the NYSE on October 2, 2002. The net proceeds from the offering of approximately $180 million were used to repay a portion of the debt we incurred to finance the Mid-America and Seminole acquisitions. As a result of the October 2002 offering, we have $314 million remaining availability under the February 2001 Shelf to use for future partnership equity or debt securities offerings.

We have the ability, under certain conditions during the Subordination Period, to issue an unlimited number of Common Units to finance acquisitions and capital improvements. The Subordination Period generally extends until the first day of any quarter beginning after June 30, 2003 when certain financial tests have been satisfied. We have the ability to issue an unlimited number of Common Units for this type of expenditure if Adjusted Operating Surplus (as defined within our partnership agreement) for each of the four fiscal quarters immediately preceding the expenditure, on a pro forma basis, would have increased as a result of such expenditure (i.e., would have been accretive on a pro forma basis for each of the quarters in the test).

For those acquisitions and other transactions that do not qualify under the aforementioned pro forma "accretive" test, we have 54,550,000 Units available (and unreserved) for general partnership purposes during the Subordination Period. After the Subordination Period expires, we may prudently issue an unlimited number of Units for general partnership purposes that do not meet the pro forma "accretive" test.

If deemed necessary, we believe that additional financing arrangements can be obtained at 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.

Credit ratings. On August 2, 2002, Moody's and S and P changed their ratings outlook regarding our debt securities from "stable" to "negative". The ratings agencies did not take any action to downgrade our ratings; they remain at Baa2 by Moody's and BBB by S and P. Their negative outlook on the future of our ratings reflects the execution risk they see associated with our permanent financing plan for the Mid-America and Seminole acquisitions, which includes the issuance of equity and long-term debt.

The change in ratings outlook does not translate into any material financial impact on our liquidity. Management is committed to achieving its goals of permanent financing for the Mid-America and Seminole acquisitions and will actively pursue the appropriate mix and timing of offerings of partnership equity and issuance of public debt that will maintain our investment grade balance sheet. We maintain regular communications with these rating agencies which independently judge our creditworthiness based on a variety of quantitative and qualitative factors.

Two-for-one split of Limited Partner Units. On February 27, 2002, we announced that the Board of Directors of the General Partner had approved a two-for-one split for each class of our Units. The partnership Unit split was accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the post-split Units, except if indicated otherwise.

Consolidated cash flows for nine months ended September 30, 2002 compared to nine months ended September 30, 2001

Operating cash flows. Cash flow from operating activities was an inflow of $170.1 million for the first nine months of 2002 compared to $124.8 million during the same period in 2001. The following table summarizes the major components of operating cash flows for the nine months ended September 30, 2002 and 2001:

	Nine Months Ended September 30, 2002	2001
Net income	$ 39,967	$220,308
Adjustments to reconcile net income to cash flows provided by (used for) operating activities before changes in operating accounts:		
Depreciation and amortization	62,907	37,245
Equity in income of unconsolidated affiliates	(22,258)	(17,350)
Distributions received from unconsolidated affiliates	40,114	30,602
Changes in fair market value of financial instruments	12,830	(39,430)

Other	8,643	9,753
Cash flow before changes in operating accounts	$142,203	$241,128
Net effect of changes in operating accounts	27,906	(116,362)
Operating activities cash flows	$170,109	$124,766

As noted in the table above, cash flow before changes in operating accounts was an inflow of $142.2 million in 2002 versus $241.1 million during 2001. "Cash flow before changes in operating accounts" is an important measure of our liquidity. We believe it provides an indication of our success in generating core cash flows from the assets and investments we own or in which we have an interest. The $98.9 million decrease in such cash flows between the two year-to-date periods is primarily due to net hedging losses

in 2002 versus net hedging income in 2001 offset by increased distributions from unconsolidated affiliates and earnings from businesses we have acquired since September 30, 2001. Of the non-cash changes in fair market value of financial instruments recorded during 2002, $10.6 million is attributable to commodity financial instruments and the remainder to interest rate swaps. For the 2001 period, $34.6 million of the $39.4 million in non-cash fair market adjustments is attributable to commodity financial instruments. Depreciation and amortization have increased between the two periods primarily due to acquisitions.

Changes in operating accounts are generally the result of timing of sales and purchases near the end of each period. A significant component of our working capital is inventory, particularly that of the NGL inventory we have available for sale in our merchant activities. At September 30, 2002, our investment in inventory was $227.1 million, an increase of $82.0 million over the September 2001 value $145.1 million. The growth in our inventory is primarily a function of the expansion of our operations over the last year as a result of acquisitions, increased equity NGL production rates, and current and forecasted market conditions for these products. We forecast that our inventories will decrease (and provide cash inflows) during the fourth quarter of 2002 as a result of normal seasonal demand for NGL products.

Investing cash flows. During the first nine months of 2002, we used $1.7 billion in cash for investing activities compared to $437.6 million spent during the first nine months of 2001. The 2002 period reflects $1.6 billion in business acquisitions including the $1.2 billion paid to acquire Mid-America and Seminole and $368.7 million paid to acquire Diamond-Koch's propylene fractionation and NGL and petrochemical storage businesses. The 2001 period includes $113 million paid to acquire equity interests in several Gulf of Mexico natural gas pipelines from El Paso (our Neptune, Starfish and Nemo equity investments) and $225.7 million paid to acquire Shell's Acadian Gas natural gas pipeline system. During the first nine months of 2002, our capital expenditures were $47.0 million compared to $92.6 million during the same period in 2001. The majority of capital expenditures during both periods is attributable to projects within our Pipelines segment.

Financing cash flows. Our financing activities generated $1.4 billion in cash inflows during the first nine months of 2002 compared to $310.5 million during the first nine months of 2001. We incurred net borrowings of $1.6 billion during the 2002 period compared to $449.7 million during the 2001 period. The increase in borrowings between the two periods is primarily due to acquisitions, particularly the $1.2 billion used to finance the Mid-America and Seminole acquisitions in July 2002 and the $239.0 million borrowed to finance the purchase of Diamond-Koch's propylene fractionation business in February 2002. The 2001 period includes the issuance of our Senior Notes B in January 2001. These notes were issued to finance the acquisition of Acadian Gas, Neptune, Nemo and Starfish; to cover construction costs of certain NGL pipelines and related projects; and to fund other general partnership activities.

Cash distributions paid to our partners increased $34.0 million period-to-period primarily due to increases in both the declared quarterly distribution rate and the number of Units entitled to receive distributions. Debt issuance costs in 2002 increased $13.4 million over 2001 primarily due to the $15.0 million in fees associated with the $1.2 billion 364-Day Term Loan. The $15.0 million in bank fees is being amortized on a straight-line basis over the 12-month term of this facility.

Cash requirements for future growth

Acquisitions. We are committed to the long-term growth and viability of the Company. Our strategy involves expansion through business acquisitions and internal growth projects. In recent years, major oil and gas companies have sold non-strategic assets in the midstream natural gas industry in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestures. Management continues to analyze potential acquisitions, joint venture or similar transactions with businesses that operate in complementary markets and geographic regions. We believe that the Company is positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth projects.

For fiscal 2002, we have invested approximately $1.7 billion in business acquisitions and internal growth projects including $1.2 billion for Mid-America and Seminole in July 2002; $239.0 million for the Mont Belvieu propylene fractionation assets we purchased

from Diamond-Koch in February 2002; and $129.6 million for the Mont Belvieu NGL and petrochemical storage assets we purchased from Diamond-Koch in January 2002. Our goal is to invest between $300 million and $500 million annually in such opportunities to the extent that we believe such investments will be accretive to our limited partners.

We expect the funds needed to achieve this goal will be obtained through a combination of operating cash flows, public and private debt and equity. Of the $1.7 billion in business acquisitions and internal growth projects we have completed thus far in 2002, we have borrowed approximately $1.5 billion of the funds required. This will translate into increased debt service costs during 2002 and 2003. To the extent proceeds from future equity offerings are used to reduce the principal amount of debt outstanding, our interest expense will be reduced. To the extent that we refinance our existing debt with new debt, our interest expense will generally be affected by any difference in interest rates on the old debt versus the new debt and by any fees associated with the new debt.

Distributions. Another stated goal of management is to increase the distribution rate to our investors by at least 10% annually. For the fourth quarter of 2001, the declared annual rate was $1.25 per Common Unit (on a post-split basis). In the third quarter of 2002, the declared annual rate was raised to $1.38 per Common Unit. Based on the number of distribution-bearing Units outstanding on record dates during 2002, we project that cash distributions to partners and minority interest will increase by approximately $52 million over the amounts paid during 2001. The number of distribution-bearing Units during 2002 increased over 2001 as a result of the conversion of 19.0 million non-distribution bearing Special Units into an equal amount of distribution-bearing Common Units in August 2002 and the issuance of 9.8 million Common Units in October 2002.

Our distribution rate is supported by prospective and historical cumulative cash flow since our IPO in July 1998. From our IPO through the third quarter of 2002, we generated $905.5 million in cash that was available for distribution to Unitholders, of which $633.6 million was paid to Unitholders (including the third quarter of 2002 distribution paid on November 12, 2002). Our policy has been to retain and reinvest the difference of $271.9 million into projects that we anticipate will be accretive in terms of cash flow to our partners over time. This policy has helped us to maintain a strong financial presence in the markets we serve by minimizing debt and using the excess cash flow to expand the partnership through internal growth and acquisitions.

We believe that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, we may temporarily borrow under our bank credit facilities for the purpose of paying distributions until the full cash flow impact of our operations are realized.

Capital spending. At September 30, 2002, we had $3.3 million in outstanding purchase commitments attributable to capital projects. Of this amount, $2.5 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.8 million is associated with capital projects of our unconsolidated affiliates which will be recorded as additional investments.

For the remainder of 2002, we expect our capital spending to approximate $33.2 million of which $18.5 million is forecasted for various projects in our Pipelines segment and $7.0 million for our expansion of the Neptune gas processing facility. Our unconsolidated affiliates forecast a combined $9.1 million in capital expenditures during the remainder of 2002 of which we expect our share to be approximately $3.5 million, the majority of which relate to expansion projects on our Gulf of Mexico natural gas pipeline systems. These outlays will be recorded as additional investments in unconsolidated affiliates.

Our debt obligations

Our debt consisted of the following at:

	September 30, 2002	December 31, 2001
Borrowings under:		
364-Day Term Loan, variable-rate, $150 million due December 2002, $450 million due March 2003 and $600 million due July 2003	$ 1,200,000	
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	$450,000
Senior Notes A, 8.25% fixed-rate, due March 2005	350,000	350,000
Multi-Year Revolving Credit facility, variable-rate, due November 2005	240,000	
364-Day Revolving Credit facility, variable-rate, due November 2003	173,000	
MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed-rate, $15 million due each December, 2002 through 2005	60,000	
Total principal amount	2,527,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,834	1,653
Less unamortized discount on:		
Senior Notes A	(90)	(117)
Senior Notes B	(237)	(258)
Less current maturities of debt	(1,215,000)	
Long-term debt	$ 1,313,507	$855,278

364-Day Term Loan and Seminole Notes. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day variable-rate term loan (the "364-Day Term Loan") to fund the acquisition of Mid-America and Seminole from Williams on July 31, 2002. The term loan will generally bear interest at either (as defined within the loan agreement) (i) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent; or (ii) a Eurodollar Rate, with any rate in effect being increased by an appropriate applicable margin. For the period in which this debt was outstanding, the weighted-average interest rate charged was 3.41%.

In October 2002, we contributed approximately $180 million in proceeds from our common equity offering to the Operating Partnership. The Operating Partnership used this amount to partially repay the 364-Day Term Loan and meet the payment required under this facility scheduled for December 2002. As of November 13, 2002, $1.0 billion remains outstanding under this facility.

On July 31, 2002, Seminole had $60 million in 6.67% fixed-rate senior unsecured notes outstanding (the "Seminole Notes"). The notes amortize by $15 million each December 1 through 2005. In accordance with generally accepted accounting principles, this debt is consolidated on our balance sheet because of our 78.4% ownership interest in Seminole.

Significant amendments to Multi-Year and 364-Day Revolving Credit facilities. The following significant amendments to the Multi-Year and 364-Day Revolving Credit facilities have been made during 2002:

- In April 2002, our total borrowing capacity under these two facilities was increased to $500 million, of which $87 million was outstanding at September 30, 2002. The amount that we can borrow under the Multi-Year Revolving Credit facility was increased by $20 million to $270 million. Likewise, the amount that we can borrow under the 364-Day Revolving Credit facility was increased by $80 million to $230 million.
- In April 2002, our debt covenants under these facilities were amended to allow us to exclude up to $50.0 million in commodity hedging losses we incurred during the first four months of 2002 from the calculation of Consolidated EBITDA (as

defined in the revolving credit agreements). The amendment also increased the ratio of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities for certain periods.
- In July 2002, we amended our Multi-Year and 364-Day Revolving Credit facility to allow us to incur additional indebtedness for the interim financing of the Mid-America and Seminole pipeline systems. This amendment provided for an increase in the amount of Consolidated Indebtedness to Consolidated EBITDA allowed under the facilities. In addition, the negative covenant on Indebtedness (as defined in the revolving credit agreements) was amended to permit the Seminole Notes.
- In October 2002, our Operating Partnership completed an amendment which refinanced its 364-Day Revolving Credit facility. The amendment, which has an effective date of November 15, 2002, extends the maturity of the current unsecured 364-Day Revolving Credit facility from November 15, 2002 to November 14, 2003.

During the first nine months of 2002, the range of interest rates paid on the Multi-Year and 364-Day Revolving Credit facilities was 2.32% to 2.59%. The weighted-average interest rates paid on Multi-Year and 364-Day Revolving Credit facilities during the period were 2.31% and 2.46%, respectively.

Guarantor relationships. Enterprise Products Partners L.P. acts as guarantor of certain of the Operating Partnership's debt obligations. This parent-subsidiary guaranty provision exists under our 364-Day Term Loan; Senior Notes A and B; MBFC Loan; and the Multi-Year and 364-Day Revolving Credit facilities.

Letters of Credit. At September 30, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility of which $2.4 million was outstanding.

Covenants. The indentures under which Senior Notes A and B and the MBFC Loan were issued contain various restrictive covenants. We were in compliance with these covenants at September 30, 2002.

The 364-Day Term Loan, Multi-Year Revolving Credit facility, and 364-Day Revolving Credit facility contain various affirmative and negative covenants applicable to the Operating Partnership. The covenants of the 364-Day Term Loan are similar to those required under the Multi-Year and 364-Day Revolving Credit facilities. As such, the 364-Day Term Loan agreement contains covenants related to our ability to incur certain indebtedness, grant certain liens, enter into certain merger or consolidation transactions, and make certain investments. In addition, the 364-Day Term Loan requires us to satisfy certain financial covenants at the end of each fiscal quarter. We were in compliance with the covenants of these three debt agreements at September 30, 2002.

The Seminole Note agreements contain various restrictive covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at September 30, 2002.

Recent accounting developments

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

For additional information regarding recent accounting developments that affected our financial statements during 2002, see Note 6 of our Notes to Unaudited Consolidated Financial Statements.

Summary of contractual obligations and material commercial commitments

The following table summarizes our contractual obligations and material purchase and other commitments for the periods shown. The values shown in the table are as of September 30, 2002 with the exception that we have reflected the use of approximately $180 million in proceeds from our October 2002 common equity offering to partially repay the 364-Day Term Loan associated with the Mid-America and Seminole acquisitions.

Contractual Obligation or Material Commercial Commitment	Total	2002	2003	2004 through 2005	2006 through 2007	After 2007
Contractual Obligation (expressed in terms of millions of dollars payable per period):						
Long-term debt	$2,349.0	$15.0	$1,210.0	$620.0		$504.0
Operating leases	$ 16.0	$ 2.7	$ 5.1	$ 5.0	$0.6	$ 2.6
Capital spending commitments:						
Property, plant and equipment	$ 2.5	$ 2.5				
Investments in unconsolidated affiliates	$ 0.8	$ 0.8				
Other commitments (expressed in terms of millions of dollars potentially payable per period):						
Letters of Credit under Multi-Year Credit Facility	$ 2.4		$ 2.4			
Other Material Contractual Obligations (Purchase commitments expressed in terms of minimum volumes under contract per period):						
NGLs (MBbls)	82,375	9,997	29,205	21,063	11,310	10,800
Petrochemicals (MBbls)	24,025	1,752	7,009	9,740	5,524	
Natural gas (BBtus)	136,461	3,652	16,416	27,797	25,595	63,000

Long-term debt. Long-term debt reflects consolidated amounts due under public and private placement obligations. For a full description of these debt obligations, see the previous section in this report entitled "*Our debt obligations*".

Operating leases. We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. The amounts shown in the table above represent minimum future rental payments due on such leases with terms in excess of one year.

Letters of Credit under our Multi-Year Credit Facility. Our outstanding letters of credit were $2.4 million at December 31, 2001 and September 30, 2002 and primarily represent letter of credit requirements associated with our purchase of hydrocarbon imports.

NGL and natural gas purchase commitments. In addition, we have long-term purchase commitments for NGL products and related-streams (including natural gas and petrochemical volumes) with several suppliers. The purchase prices contained within these contracts approximate market value at the time of delivery. Our purchase commitments for NGLs and petrochemicals are stated in thousands of barrels and for natural gas in BBtus. These amounts have increased since December 31, 2001 as a result of acquisitions completed during 2002.

Uncertainties regarding our investment in BEF

We have a 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. MTBE has come under scrutiny by various governmental agencies and environmental groups over the last few years because underground storage tanks filled with motor gasoline containing MTBE have leaked contaminating water supplies. Certain states, primarily California, have moved to ban or reduce MTBE use due to these concerns. The California ban takes effect during the first quarter of 2004. In addition, the U.S. Senate, in April 2002, passed an energy bill that includes a total ban on the use of MTBE, which if ultimately adopted would be effective in four years. The Senate bill is now in a conference committee with the U.S. House of Representatives for resolution. The U.S. House of Representatives energy bill, which passed in August 2001, contains no such ban. We can give no assurance as to whether the federal government or individual states will ultimately adopt legislation banning the use of MTBE.

In April 2002, a jury in California found three energy companies liable for polluting Lake Tahoe's drinking water with MTBE. While this decision sets no legal precedent, this was the first time that a jury has defined gasoline containing MTBE to be a "defective product". This development has no direct impact on BEF since our customer uses the MTBE we produce in its eastern U.S. operations.

In light of these developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently leaning towards a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical quality of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of the first quarter of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

Conversion of EPCO Subordinated Units to Common Units

As a result of the Company satisfying certain financial tests, 10,704,936 (or 25%) of EPCO's Subordinated Units converted to Common Units on May 1, 2002. If the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units will undergo an early conversion on a one-for-one basis to Common Units on May 1, 2003. The remaining 50% of Subordinated Units will convert on August 1, 2003 if the balance of the conversion requirements are met. Subordinated Units have limited voting rights until converted to Common Units. The conversion(s) will have no impact upon our earnings per unit since the Subordinated Units are already included in both the basic and fully diluted calculations.

Conversion of Shell Special Units to Common Units

In accordance with existing agreements with Shell, 19.0 million of Shell's non-distribution bearing Special Units converted to distribution-bearing Common Units on August 1, 2002. The remaining 10.0 million Special Units will convert to Common Units on a one-for-one basis in August 2003. These conversions have a dilutive impact on basic earnings per Unit.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in our Processing segment. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes. For additional information regarding our financial instruments, see the Notes to our Unaudited Consolidated Financial Statements.

Commodity price risk

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities (or hedging strategies) is to hedge exposure to price risks associated with natural gas, NGL inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in our Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas and to manage the price risk of certain energy costs of our Mid-America pipeline system.

We have adopted a financial commodity and commercial policy to manage our exposure to the risks of our natural gas and NGL businesses. The objective of these policies is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. Under these policies, we enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than one month) and long-term basis, generally not to exceed 24 months. The General Partner oversees our hedging strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policies (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policies.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. When financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these ineffective instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis performed on this portfolio measures the potential income or loss (e.g., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates noted within the following table. In general, we derive the quoted market prices used in the model from those actively quoted on commodity exchanges (i.e.,NYMEX) for instruments of similar duration. In those rare instances where prices are not actively quoted, we employ regression analysis techniques possessing strong correlation factors.

The sensitivity analysis model takes into account the following primary factors and assumptions:

- the current quoted market price of natural gas;
- the current quoted market price of NGLs;
- changes in the composition of commodities hedged (i.e., the mix between natural gas and related NGLs);
- fluctuations in the overall volume of commodities hedged (for both natural gas and related NGL hedges outstanding);
- market interest rates, which are used in determining the present value; and
- a liquid market for such financial instruments.

An increase in fair value of the commodity financial instruments (based upon the factors and assumptions noted above) approximates the income that would be recognized if all of the commodity financial instruments were settled at the dates noted within the table. Conversely, a decrease in fair value of the commodity financial instruments would result in the recording of a loss.

The sensitivity analysis model does not include the impact that the same hypothetical price movement would have on the hedged commodity positions to which they relate. Therefore, the impact on the fair value of the commodity financial instruments of a change in commodity prices would be offset by a corresponding gain or loss on the hedged commodity positions, assuming:

- the commodity financial instruments function effectively as hedges of the underlying risk;
- the commodity financial instruments are not closed out in advance of their expected term; and
- as applicable, anticipated underlying transactions settle as expected.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

The following table shows the impact of hypothetical price movements on our commodity financial instrument portfolio at the dates indicated:

Scenario	Resulting classification	At 12/31/01	At 09/30/02	At 11/04/02
		(in millions of dollars)		
Fair Value assuming no change in quoted market prices	Asset (Liability)	$ 5.6	$(2.7)	$(0.5)
Fair Value assuming 10% increase in quoted market prices	Asset (Liability)	$(0.3)	$(5.3)	$(0.6)
Earnings Impact assuming 10% increase in quoted market prices	Income (Loss)	$(5.9)	$(2.6)	$(0.1)
Fair Value assuming 10% decrease in quoted market prices	Asset (Liability)	$11.4	$(0.1)	$(0.4)
Earnings Impact assuming 10% decrease in quoted market prices	Income (Loss)	$ 5.8	$ 2.6	$ 0.1

The estimated value of our commodity hedging portfolio was a $5.6 million asset at December 31, 2001. At that time, our portfolio was primarily based on a hedging strategy that utilized the forward sale of natural gas at a fixed-price with the expected margin on the settlement of the position offsetting or mitigating changes in anticipated margins on NGL merchant activities and the value of our equity NGL production. This strategy was successful during periods of falling natural gas prices (as was the case during most of 2001) and we continued to use this strategy going into 2002 believing that the fundamentals of the natural gas business indicated additional moderation in prices. Unfortunately, the price of natural gas became unstable and rapidly increased as speculation surrounding potential natural gas shortages began to influence the market in March 2002. As the market price of natural gas increased, our fixed positions became less and less profitable until we were finally left in a payable position (i.e., in a loss position on these instruments). As a result, we recognized a loss from our commodity hedging activities for the first quarter of 2002 of $45.1 million.

Due to the inherent uncertainty that was controlling the markets, management decided that it was prudent for the Company to exit this strategy and we did so by late April 2002. By the time that these positions were generally closed out in late April, we had incurred additional losses. For the nine months ending September 30, 2002, we recorded commodity hedging losses of $52.3 million, with nearly all of the loss attributable to the strategy that we closed in April 2002. Of the $52.3 million in losses recorded to date during 2002, $41.7 million represents cash payments to counterparties and $10.6 million results from mark-to-market adjustments (of which $7.9 million is related to mark-to-market income we recognized in the fourth quarter of 2001 from this portfolio).

Our current hedging strategies are limited in scope and duration. These strategies primarily cover the price risk associated with fuel costs at our natural gas processing facilities. The mark-to-market value of the portfolio at September 30, 2002 was $2.7 million payable. The change in overall portfolio value between December 31, 2001 and September 30, 2002 primarily reflects the settlement of transactions and changes in strategy that occurred during the first nine months 2002. The value of the portfolio was $0.5 million payable at November 4, 2002. The change in portfolio value between September 30, 2002 and November 4, 2002 is primarily the result of normal settlement activity and the early closeout of certain financial instruments used to hedge fuel inventories.

Interest rate risk

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the Company's Senior Notes and MBFC Loan. We manage a portion of our exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding interest rate swaps is to manage debt service costs by converting a portion of fixed-rate debt into variable-rate debt or a portion of variable-rate debt into fixed-rate debt. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount.

The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements. At September 30, 2002, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010 . Under this agreement, we exchanged a fixed-rate of 8.70% for a market-based variable-rate. If the counterparty elects to do so, it may terminate this swap in March 2003. The fair value of this interest rate swap at September 30, 2002 was $1.6 million. If quoted market interest rates were to have been 10% higher or lower on this date, the change in fair value of this swap would have minimal effect on our earnings.

Our interest rate hedging portfolio was expanded in October 2002 to include three treasury lock transactions. A treasury lock is a specialized agreement that fixes the price or yield on a specific treasury security for an established period. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. Our treasury lock transactions have a maturity date of April 15, 2003. The purpose of these transactions was to hedge an underlying 10-year treasury note for a possible issuance of 10-year notes in early 2003. The notional amounts of these transactions totaled $250 million, with a total treasury lock rate of approximately 3.9%. The fair value of our interest rate hedging portfolio was $7.4 million at November 6, 2002. The fair value of the portfolio at this date would increase to a $15.4 million receivable if quoted market interest rates were to increase by 10% and decline to a $0.8 million payable if quoted market interest rates were to decrease by 10%. To the extent the treasury locks are effective in hedging interest expense, the change in fair value of the treasury locks would be charged to earnings over the life of the anticipated debt offering. If any portion of the treasury locks are deemed ineffective as hedging instruments under current accounting guidance, all or a portion of the change in fair value of these treasury locks will be recorded to earnings through mark-to-market accounting. Our interest rate swap is accounted for using the mark-to-market method.

We recognized income of $0.1 million and $0.8 million for the three and nine months ended September 30, 2002, respectively, that is treated as a reduction of interest expense in our Statements of Consolidated Operations. For the three months and nine months ended September 30, 2001, we recorded income from interest rate hedging activities of $3.8 million and $11.3 million, respectively.

At September 30, 2002 and December 31, 2001, we had no financial instruments in place to cover any potential interest rate risk on our variable-rate obligations. Variable interest-rate debt obligations expose us to possible increases in interest expense and decreases in earnings if interest rates were to rise. Our 364-Day Term Loan, Multi-Year Revolving Credit and 364-Day Revolving Credit facilities are variable-rate debt obligations. At September 30, 2002, approximately $1.6 billion was outstanding under these three facilities. At December 31, 2001, we had no variable-rate debt outstanding.

If the weighted-average base interest rates selected on the variable-rate long-term debt during the first nine months of 2002 were to have been 10% higher than the weighted-average of the actual base interest rates selected, assuming no changes in the weighted-average debt levels, interest expense would have increased by approximately $0.9 million with a corresponding decrease in earnings before minority interest.

Item 4. CONTROLS AND PROCEDURES

In the 90-day period before the filing of 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. These disclosure controls and procedures are those controls and other procedures we maintain,

which are designed to insure 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 ensure 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.

Subsequent to the date when the disclosure controls and procedures were evaluated, there have not been any significant changes in the registrants' controls or procedures or in other factors that could significantly affect such controls or procedures. No significant deficiencies or material weaknesses were detected, so no corrective actions needed to be taken.

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

(a) Exhibits.

2.1 Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated as of September 22, 2000. (Exhibit 10.1 to the Company's Form 8-K filed on September 26, 2000).

2.2 Purchase and Sale Agreement dated as of January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (Exhibit 10.1 to the Company's Form 8-K filed February 8, 2002).

2.3 Purchase and Sale Agreement dated as of 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. (Exhibit 10.2 to the Company's Form 8-K filed February 8, 2002).

2.4 Purchase Agreement dated as of July 31, 2002 by and between E-Birchtree, LLC and E-Cypress, LLC (Exhibit 2.1 to the Company's Form 8-K filed August 12, 2002).

2.5 Purchase Agreement dated as of July 31, 2002 by and between E-Birchtree, LLC and Enterprise Products Operating L.P.(Exhibit 2.2 to the Company's Form 8-K filed August 12, 2002).

3.1 Form of Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. (Exhibit 3.2 to the Company's Registration Statement of Form S-1/A, File No. 333-52537, filed on July 21, 1998).

3.2 First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated September 17, 1999. (Exhibit 99.8 on the Company's Form 8-K/A-1 filed October 27, 1999).

3.3 Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 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.

4.1 Form of Common Unit certificate. (Exhibit 4.1 to the Company's Registration Statement on Form S-1/A, File No. 333-52537, filed on July 21, 1998).

4.2 Unitholder Rights Agreement among Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "C" to the Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).

4.3 Contribution Agreement by and among Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "B" to the Schedule 13 D filed September 27, 1999 by Tejas Energy, LLC).

4.4 Registration Rights Agreement between Tejas Energy LLC and Enterprise Products Partners L.P. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "E" to the Schedule 13 D filed September 27, 1999 by Tejas Energy, LLC).

4.5 Form of 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. (Exhibit 4.1 on the Company's Form 8-K filed March 10, 2000).

4.6 Form of Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (the "Senior Notes A"). (Exhibit 4.2 on the Company's Form 8-K filed March 10, 2000).

4.7 $250 million Multi-Year Revolving Credit Agreement (the "Multi-Year Credit Facility") among Enterprise Products Operating L.P., First Union National Bank, as administrative agent; Bank One, NA, as documentation agent; and The Chase Manhattan Bank, as syndication agent and the Several Banks from time to time parties thereto dated November 17, 2000. (Exhibit 4.2 on the Company's Form 8-K filed January 25, 2001).

4.8 $150 Million 364-Day Revolving Credit Agreement (the "364-Day Credit Facility") among Enterprise Products Operating L.P. and First Union National Bank, as administrative agent; Bank One, NA, as documentation agent; and The Chase Manhattan Bank, as syndication agent and the Several Banks from time to time parties thereto dated November 17, 2000. (Exhibit 4.3 on the Company's Form 8-K filed January 25, 2001).

4.9 Guaranty Agreement (relating to the Multi-Year Credit Facility) by Enterprise Products Partners L.P. in favor of First Union National Bank, as administrative agent dated November 17, 2000. (Exhibit 4.4 on the Company's Form 8-K filed January 25, 2001).

4.10 Guaranty Agreement (relating to the 364-Day Credit Facility) by Enterprise Products Partners L.P. in favor of First Union National Bank, as administrative agent dated November 17, 2000. (Exhibit 4.5 on the Company's Form 8-K filed January 25, 2001).

4.11 Form of Global Note representing $450 million principal amount of 7.50% Senior Notes due 2011 (the "Senior Notes B"). (Exhibit 4.1 to the Company's Form 8-K filed January 25, 2001).

4.12 First Amendment to Multi-Year Revolving Credit facility dated April 19, 2001. (Exhibit 4.12 to the Company's Form 10-Q filed May 14, 2001).

4.13 First Amendment to 364-Day Revolving Credit facility dated November 6, 2001, effective as of November 16, 2001. (Exhibit 4.13 to the Company's Form 10-K filed March 21, 2002).

4.14 Second Amendment and Supplement to Multi-Year Revolving Credit facility dated April 24, 2002. (Exhibit 4.14 to the Company's Form 10-Q filed May 14, 2002).

4.15 Second Amendment and Supplement to 364-Day Revolving Credit facility dated April 24, 2002. (Exhibit 4.15 to the Company's Form 10-Q filed May 14, 2002).

4.16 Third Amendment and Supplement to Multi-Year Revolving Credit facility dated July 31, 2002. (Exhibit 4.1 to the Company's Form 8-K filed August 12, 2002).

4.17 Third Amendment and Supplement to 364-Day Revolving Credit facility dated July 31, 2002. (Exhibit 4.2 to the Company's Form 8-K filed August 12, 2002).

4.18 Guaranty Agreement (relating to the $1.2 billion 364-Day Term Loan Credit Agreement) by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as administrative agent dated July 31, 2002. (Exhibit 4.4 to the Company's Form 8-K filed August 12, 2002).

4.19* Fourth Amendment and Supplement to 364-Day Revolving Credit facility dated November 15, 2002.

10.1 $1.2 billion 364-Day Term Loan Credit Agreement among Enterprise Products Operating L.P.; Wachovia Bank, National Association, as administrative agent; Lehman Commercial Paper Inc., as co-syndication agent; and the Royal Bank of Canada, as co-syndication agent and arranger dated July 31, 2002. (Exhibit 4.3 to the Company's Form 8-K filed August 12, 2002).

10.2 First Amendment and Supplement to $1.2 billion 364-Day Term Loan Credit Agreement dated July 31, 2002. (Exhibit 4.4 to the Company's Form 8-K/A filed September 26, 2002).

12.1* Computation of ratio of earnings to fixed charges for the nine months ended September 30, 2002 and each of the five years ended December 31, 2001, 2000, 1999, 1998 and 1997 for Enterprise Products Partners L.P.

12.2* Computation of ratio of earnings to fixed charges for the nine months ended September 30, 2002 and each of the five years ended December 31, 2001, 2000, 1999, 1998 and 1997 for Enterprise Products Operating L.P.

* An asterisk indicates that an exhibit is filed in conjunction with this report. All other documents are incorporated by reference as indicated in their descriptions.

(b) Reports on Form 8-K.

August 12, 2002 filings: (Item 2) On August 1, 2002, we announced the purchase of equity interests in affiliates of The Williams Companies, Inc.("Williams"), which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America", formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole").

(Item 9) On August 9, 2002, Enterprise Products Partners L.P. submitted to the SEC the Statements under Oath of Principal Executive Officer and Principal Financial Officer in accordance with the SEC's File No. 4-460 Order requiring the filing of sworn statements pursuant to Section 21(a)(1) of the Securities and Exchange Act of 1934.

September 26, 2002 filing: (Form 8-K/A, Items 2 and 7) On September 26, 2002, we filed the required audited and unaudited financial statements (including certain pro forma information) pertaining to the Mid-America and Seminole acquisitions.

September 27, 2002 filing:(Items 5 and 7) On May 15, 2002, Enterprise Products Partners L.P. completed a two-for-one split of its Common Units, Subordinated Units and Special Units. Accordingly, we revised our consolidated financial statements and the notes thereto to retroactively reflect the effects of the two-for-one split.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 13, 2002.

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

Date: November 13, 2002

By: /s/ Michael J. Knesek

Name: Michael J. Knesek
Title: Vice President, Controller and Principal Accounting Officer of the General Partner

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P. PURSUANT TO 18 U.S.C.ss.1350

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-13 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 quarterly report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and
   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 13, 2002

/s/ O.S. Andras

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

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P. PURSUANT TO 18 U.S.C.ss.1350

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-13 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 quarterly report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and
   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: Novemer 13, 2002

/s/ Michael A. Creel

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

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P. PURSUANT TO 18 U.S.C.ss.1350

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-13 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 quarterly report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and
   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 13, 2002

/s/ O.S. Andras

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

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P. PURSUANT TO 18 U.S.C.ss.1350

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-13 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures 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 quarterly report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and
   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 13, 2002

/s/ Michael A. Creel

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

FOURTH AMENDMENT AND SUPPLEMENT
TO CREDIT AGREEMENT

EFFECTIVE AS OF NOVEMBER 15, 2002

AMONG

ENTERPRISE PRODUCTS OPERATING L.P.

THE LENDERS PARTY HERETO

WACHOVIA BANK, NATIONAL ASSOCIATION,
AS ADMINISTRATIVE AGENT

ROYAL BANK OF CANADA AND
SUNTRUST BANK,
AS CO-DOCUMENTATION AGENTS

BANK ONE, N.A. AND THE BANK OF NOVA SCOTIA,
AS CO-SYNDICATION AGENTS

WACHOVIA SECURITIES, INC.,
AS SOLE ARRANGER AND SOLE BOOK MANAGER

364-DAY REVOLVING CREDIT FACILITY

FOURTH AMENDMENT AND SUPPLEMENT
TO CREDIT AGREEMENT
(364-Day Credit Facility)

THIS FOURTH AMENDMENT AND SUPPLEMENT TO CREDIT AGREEMENT (this "Fourth Amendment") is made and entered into effective as of the 15th day of November, 2002 (the "Fourth Amendment Effective Date"), among ENTERPRISE PRODUCTS OPERATING L.P., a Delaware limited partnership (the "Borrower"); WACHOVIA BANK, NATIONAL ASSOCIATION (formerly known as First Union National Bank), as administrative agent (in such capacity, the "Administrative Agent") for each of the lenders (the "Lenders") that is a signatory or which becomes a signatory to the hereinafter defined Credit Agreement; and the Lenders party hereto.

R E C I T A L S:

A. On November 17, 2000, the Borrower, the Lenders and the Administrative Agent entered into a certain Credit Agreement (as amended and supplemented by First Amendment and Supplement to Credit Agreement dated November 6, 2001, effective as of November 16, 2001, and as further amended and supplemented by a Second Amendment and Supplement to Credit Agreement dated as of April 24, 2002, and by a Third Amendment and Supplement to Credit Agreement dated effective as of July 31, 2002, (the "Credit Agreement") whereby, upon the terms and conditions therein stated, the Lenders agreed to make certain Loans (as defined in the Credit Agreement) and extend certain credit to the Borrower.

B. The parties hereto mutually desire to further amend the Credit Agreement as hereinafter set forth.

C. Each of Fleet National Bank and Toronto Dominion (Texas), Inc. (collectively, the "Retiring Lenders")desire to cease being a Lender.

D. Each of Lehman Brothers Bank and UBS AG, Stamford Branch (the "New Lenders") desires to become a "Lender" under the Credit Agreement and to purchase Commitments and Loans from the Lenders party to the Credit Agreement prior to the effectiveness of this Fourth Amendment (the "Existing Lenders").

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Borrower, the Lenders party hereto and the Administrative Agent hereby agree as follows:

1. Certain Definitions.

1.1 Terms Defined Above. As used in this Fourth Amendment, the terms "Administrative Agent", "Borrower", "Credit Agreement", "Existing Lenders", "Fourth Amendment", "Fourth Amendment Effective Date", "New Lenders" and "Retiring Lenders", shall have the meanings indicated above.

1.2 Terms Defined in Agreement. Unless otherwise defined herein, all terms beginning with a capital letter which are defined in the Credit Agreement shall have the same meanings herein as therein unless the context hereof otherwise requires.

2. Assignments.

2.1 The Existing Lenders hereby sell and assign, without recourse, to the New Lenders, and the New Lenders hereby purchase and assume, without recourse, from the Assignors, effective as of the Fourth Amendment Effective Date all of the interests of the Retiring Lenders and so much of the interests (collectively, the "Assigned Interests") in the other Existing Lenders' rights and obligations under the Credit Agreement, including, without limitation, the interests in the Commitments and the Loans of the

Existing Lenders on the Fourth Amendment Effective Date, but excluding accrued interests and fees to but excluding the Fourth Amendment Effective Date, as will result, after giving effect to the Assigned Interests, in each Existing Lender (other than the Retiring Lenders) and each New Lender having the Commitment on Schedule 2.01 hereto.

2.2 Each New Lender hereby acknowledges receipt of a copy of the Credit Agreement. From and after the Fourth Amendment Effective Date (a) each New Lender shall be a party to and be bound by the provisions of the Credit Agreement and, to the extent of its Assigned Interest, have the rights and obligations of a Lender thereunder and (b) each Existing Lender shall, to the extent of its Assigned Interest, relinquish its rights and be released from its obligations under the Credit Agreement, it being understood that the Retiring Lenders shall relinquish all such rights and be released from all such obligations.

3. Amendments to Credit Agreement.

3.1 Defined Terms.

(a) The term "Agreement," as defined in Section 1.01 of the Credit Agreement, is hereby amended to mean the Credit Agreement, as amended and supplemented by this Fourth Amendment and as the same may from time to time be further amended or supplemented.

(b) The term "Applicable Rate" is hereby amended in its entirety to read as follows:

" `Applicable Rate' means, for any day, with respect to any Eurodollar Loan, ABR Loan, or with respect to the facility fees payable hereunder, as the case may be, subject to the two immediately following paragraphs of this defined term), the applicable rate per annum set forth below under the caption "Eurodollar Spread", "ABR Spread" or "Facility Fee Rate", as the case may be, based upon the ratings by Moody's and S and P, respectively, applicable on such date to the Index Debt:

	Index Debt Ratings: (Moody's/S and P)	Eurodollar Spread	ABR Spread	Facility Fee Rate
Category 1	greater or = A3/A-	0.415%	0.0%	0.085%
Category 2	greater or = Baa1/BBB+	0.525%	0.0%	0.100%
Category 3	greater or = Baa2/BBB	0.625%	0.0%	0.125%
Category 4	greater or = Baa3/BBB-	0.825%	0.0%	0.175%
Category 5	less than Baa3/BBB-	1.050%	0.0%	0.200%

For purposes of the foregoing, (a) if either Moody's or S and P shall not have in effect a rating for the Index Debt (other than by reason of the circumstances referred to in the penultimate sentence of this definition), then such rating agency shall be deemed to have established a rating in the same Category as the other rating agency; (b) if the ratings established by Moody's and S and P for the Index Debt shall fall within different Categories, the Applicable Rate shall be based on the higher of the two ratings unless one of the two ratings is two or more Categories lower than the other, in which case the Applicable Rate shall be determined by reference to the Category one rating higher than the lower of the two ratings; and (c) if the ratings established or deemed to have been established by Moody's and S and P for the Index Debt shall be changed (other than as a result of a change in the rating system of Moody's or S and P), such change shall be effective as of the date on which it is first announced by the applicable rating agency. Each change in the Applicable Rate shall apply during the period commencing on the effective date of such change and ending on the date immediately preceding the effective date of the next such change. If the rating system of Moody's or S and P shall change, or if either such rating agency shall cease to be in the business of rating corporate debt obligations, the Borrower and the Lenders shall negotiate in good faith to amend this definition to reflect such changed rating system or the unavailability of ratings from such rating agency and, pending the effectiveness of any such amendment, the Applicable Rate shall be determined by reference to the rating most recently in effect prior to such change or cessation.

Notwithstanding the foregoing (a) the Eurodollar Spread and the ABR Spread, as otherwise determined as above provided, shall increase by .50% for the period from and after the Fourth Amendment Effective Date to the last day of the first fiscal quarter ending thereafter at which the ratio of Consolidated Indebtedness to Consolidated EBITDA, calculated as provided in Section 6.07(b), shall be equal to or less than 4.50 to 1.0, and (b) if at any time or from time to time at the end of any fiscal quarter ending thereafter (a "Determination Date") the ratio of Consolidated Indebtedness to Consolidated EBITDA, calculated as provided in Section 6.07(b), shall exceed 4.50 to 1.0, the Eurodollar Spread and the ABR Spread, as otherwise determined as above provided, shall increase by .50% for the period from and including the Determination Date to the last day of the first fiscal quarter ending thereafter at which the ratio of Consolidated Indebtedness to Consolidated EBITDA, calculated as provided in Section 6.07(b), shall be equal to or less than 4.50 to 1.0; provided, for avoidance of doubt, that any increase pursuant to the foregoing clause (b) shall occur, if at all, only after the increase pursuant to clause (a) has ceased to be in effect."

(c) The term "Commitment" is hereby amended in its entirety to read as follows:

" `Commitment' means, with respect to each Lender, the commitment of such Lender to make Loans hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Exposure hereunder, as such commitment may be (a) reduced from time to time pursuant to Section 2.09 and (b) reduced or increased from time to time pursuant to Section 2.01 or assignments by or to such Lender pursuant to Section 9.04. The initial amount of each Lender's Commitment is set forth on Schedule 2.01 to the Fourth Amendment, or in the Assignment and Acceptance pursuant to which such Lender shall have assumed its Commitment, as applicable. The aggregate amount of the Lenders' Commitments on the Fourth Amendment Effective Date is $230,000,000."

(d) The term "Conversion" is hereby amended in its entirety to read as follows

" `Conversion' means the conversion of the outstanding Revolving Loans to Term Loans pursuant to the terms and conditions of Section 2.01(d), which conversion shall occur on November 14, 2003, unless the Availability Period is extended pursuant to Section 2.01(c)."

3.2 Additional Defined Terms. Section 1.01 of the Credit Agreement is hereby further amended and supplemented by adding the following new definitions, which read in their entirety as follows:

" `Fourth Amendment' means that certain Fourth Amendment and Supplement to Credit Agreement dated effective as of November 15, 2002, among the Borrower, the Lenders party thereto and the Administrative Agent.

`Fourth Amendment Effective Date' means November 15, 2002."

3.3 Amendment to Section 2.12. Section 2.12 of the Credit Agreement is hereby amended in its entirety to read as follows:

"SECTION 2.12. Fees. (a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender a facility fee, which shall accrue at the Applicable Rate on the daily amount of the Commitment of such Lender (whether used or unused) during the period from and including the Effective Date to but excluding the date on which such Commitment terminates; provided that, if such Lender continues to have any Exposure after its Commitment terminates, then such facility fee shall continue to accrue on the daily amount of such Lender's Exposure from and including the date on which its Commitment terminates to but excluding the date on which such Lender ceases to have any Exposure. Accrued facility fees shall be payable in arrears on the last day of March, June, September and December of each year and on the date on which the Commitments terminate, commencing on the first such date to occur after the date hereof; provided that any facility fees accruing after the date on which the Commitments terminate shall be payable on demand. All facility fees and utilization fees shall be computed on the basis of a year of 365 days (or 366 days in leap year) and shall be payable for the actual number of days elapsed (including the first day but excluding the last day). In addition to the foregoing, the Borrower agrees to pay to the Administrative Agent for the account of each Lender a utilization fee, which shall accrue and be payable on Loans made hereunder at a rate of 0.125% per annum whenever the aggregate amount of Loans outstanding plus amounts outstanding under the Multi-Year Credit Facility exceed 50% of the total Commitments plus the Multi-Year Credit Facility Commitments.

(b) In the event the Borrower elects to convert the Revolving Loans to Term Loans pursuant to Section 2.01(d), the Borrower agrees to pay to the Administrative Agent for the account of each Lender a term-out fee of 0.25% on the Loans of such Lender outstanding on the last day of the Final Availability Period, payable on such date.

(c) The Borrower agrees to pay to the Administrative Agent, for its own account, fees payable in the amounts and at the times separately agreed upon between the Borrower and the Administrative Agent.

(d) All fees payable hereunder shall be paid on the dates due, in immediately available funds, to the Administrative Agent for distribution, in the case of facility fees, utilization fees, participation and term-out fees, to the Lenders. Fees paid shall not be refundable under any circumstances."

3.4 Amendment to Section 2.13(a). Section 2.13(a) of the Credit Agreement is hereby amended in its entirety to read as follows:

"(a) The Loans comprising each ABR Borrowing shall bear interest at the Alternate Base Rate plus the Applicable Rate."

4. Conditions Precedent. In addition to all other applicable conditions precedent contained in the Credit Agreement, the obligation of the Lenders party hereto and the Administrative Agent to enter into this Fourth Amendment shall be conditioned upon the following conditions precedent:

(a) The Administrative Agent shall have received a copy of this Fourth Amendment, duly completed and executed by the Borrower and the Required Lenders; and acknowledged and ratified by the Limited Partner;

(b) The Administrative Agent shall have received such other information, documents or instruments as it or its counsel may reasonably request.

5. Representations and Warranties. The Borrower represents and warrants that:

(a) there exists no Default or Event of Default; and

(b) the representations and warranties of the Borrower contained in the Credit Agreement, as hereby amended and supplemented, were true and correct when made, and are true and correct in all material respects at and as of the time of delivery of this Fourth Amendment, except to the extent such representations and warranties relate to an earlier date, in which case such representations and warranties were true and correct in all material respects as of such earlier date.

6. Extent of Amendments. Except as expressly herein set forth, all of the terms, conditions, defined terms, covenants, representations, warranties and all other provisions of the Credit Agreement are herein ratified and confirmed and shall remain in full force and effect.

7. Counterparts. This Fourth Amendment may be executed in two or more counterparts, and it shall not be necessary that the signatures of all parties hereto be contained on any one counterpart hereof; each counterpart shall be deemed an original, but all of which together shall constitute one and same instrument.

8. References. On and after the Fourth Amendment Effective Date:

(a) the terms "Agreement", "hereof", "herein", "hereunder", and terms of like import when used in the Credit Agreement shall, except where the context otherwise requires, refer to the Credit Agreement, as amended and supplemented by this Fourth Amendment.

(b) each Retiring Lender shall cease to be a "Lender" under the Credit Agreement.

(c) each New Lender shall be a "Lender" under the Credit Agreement as amended hereby and each Lender shall have the Commitment set forth on Schedule 2.01 hereto.

9. Governing Law. This Fourth Amendment shall be governed by and construed in accordance with the laws of the State of New York and applicable federal law.

THIS FOURTH AMENDMENT, THE CREDIT AGREEMENT, AS AMENDED HEREBY, THE NOTES AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES.

THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

This Fourth Amendment shall benefit and bind the parties hereto, as well as their respective assigns, successors, heirs and legal representatives.

[Signatures Begin on Next Page]

EXECUTED as of the Fourth Amendment Effective Date.

BORROWER:

ENTERPRISE PRODUCTS OPERATING L.P.

By: Enterprise Products GP, LLC ,
General Partner

By: /s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Vice President and Treasurer

LENDERS AND AGENTS:

WACHOVIA BANK, NATIONAL
ASSOCIATION (formerly known as
First Union National Bank), Individually
and as Administrative Agent

By: /s/ Russell T. Clingman
Name: Russell T. Clingman
Title: Director

ROYAL BANK OF CANADA,
Individually and as Co-Documentation Agent

By: /s/ Tom J. Oberaigner
Name: Tom J. Oberaigner
Title: Senior Manager

SUNTRUST BANK,
Individually and as Co-Documentation Agent

By: /s/ David J. Edge
Name: David J. Edge
Title: Director

BANK ONE, NA (Main Office - Chicago),
Individually and as Co-Syndication Agent

By: /s/ Kenneth J. Fatur
Name: Kenneth J. Fatur
Title: Director, Capital Markets

THE BANK OF NOVA SCOTIA,
Individually and as Co-Syndication Agent

By: /s/ N. Bell
Name: N. Bell
Title: Senior Manager

MIZUHO CORPORATE BANK, LTD.,
Individually and as Managing Agent

By: /s/ Hirofumi Sugano
Name: Hirofumi Sugano
Title: Senior Vice President

WESTDEUTSCHE LANDESBANK
GIRONZENTRALE, NEW YORK BRANCH,

Individually and as Co-Documentation Agent

By: /s/ Salvatore Battinelli /s/ Duncan M. Robertson
Name: Salvatore Battinelli Duncan M. Robertson
Title: Managing Director Director
Credit Department

GUARANTY BANK

By: /s/ James R. Hamilton
Name: James R. Hamilton
Title: Senior Vice President

HIBERNIA NATIONAL BANK

By: /s/ Nancy G. Moragas
Name: Nancy G. Moragas
Title: Vice President

BANK OF TOKYO-MITSUBISHI, LTD.,
HOUSTON AGENCY

By: /s/ Kelton Glasscock
Name: Kelton Glasscock
Title: Vice President and Manager

CITIBANK, N.A.

By: /s/ Douglas A. Whiddon
Name: Douglas A. Whiddon
Title: Attorney-in-Fact

LEHMAN BROTHERS BANK

By: /s/ Gary T. Taylor
Name: Gary T. Taylor
Title: Vice President

UBS AG, STAMFORD BRANCH

By: /s/ Patricia O'Kicki
Name: Patricia O'Kicki
Title: Director

By: /s/ Thomas Salzano
Name: Thomas Salzano
Title: Director

RETIRING LENDERS:

FLEET NATIONAL BANK,
Individually and as Co-Documentation Agent

By: /s/ Christopher C. Holmgren
Name: Christopher C. Holmgren
Title: Managing Director

TORONTO DOMINION (TEXAS), INC.

By: /s/ Debbie A. Greene
Name: Debbie A. Greene
Title: Vice President

ACKNOWLEDGMENT AND RATIFICATION OF GUARANTOR

The undersigned ("Guarantor") hereby expressly (i) acknowledges the terms of the foregoing Fourth Amendment and Supplement to Credit Agreement; (ii) ratifies and affirms its obligations under its Guaranty Agreement dated as of November 17, 2000, in favor of the Administrative Agent; (iii) acknowledges, renews and extends its continued liability under said Guaranty Agreement and Guarantor hereby agrees that its Guaranty Agreement remains in full force and effect; and (iv) guarantees to the Administrative Agent the prompt payment when due of all amounts owing or to be owing by it under its Guaranty Agreement pursuant to the terms and conditions thereof, as modified hereby.

The foregoing acknowledgment and ratification of the undersigned Guarantor shall be evidenced by signing the spaces provided below, to be effective as of Fourth Amendment Effective Date.

ENTERPRISE PRODUCTS PARTNERS L.P.,
a Delaware limited partnership

By: Enterprise Products GP, LLC,
General Partner

By: /s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Vice President and Treasurer

SCHEDULE 2.01

Lender	Commitment
Wachovia Bank, National Association	$25,000,000.00
Royal Bank of Canada	24,000,000.00
SunTrust Bank	24,000,000.00
Bank One, NA	22,000,000.00
The Bank of Nova Scotia	22,000,000.00
Lehman Brothers Bank	22,000,000.00
Citibank, N.A.	19,000,000.00
UBS AG, Stamford Branch	19,000,000.00
Westdeutsche Landesbank Gironzentrale, New York Branch	15,000,000.00
Mizuho Corporate Bank, Ltd.	15,000,000.00
Bank of Tokyo - Mitsubishi, Ltd., Houston Agency	10,000,000.00
Guaranty Bank	7,500,000.00
Hibernia National Bank	5,500,000.00
Total	$230,000,000.00

Computation of Ratio of Earnings to Fixed Charges
for the nine months ended September 30, 2002 and each of the five years ended
December 31, 2001, 2000, 1999, 1998 and 1997 for Enterprise Products Partners L.P.
(dollars in millions)

	Nine Months Ended Sept. 30,	For the Year Ended December 31,				
	2002	2001	2000	1999	1998	1997
Income (loss) before minority interest, taxes and equity investments	$21.1	$219.3	$198.6	$108.0	$(5.5)	$37.0
Add:						
Fixed charges	73.6	60.3	43.7	23.5	21.5	37.6
Amortization of capitalized interest	0.2	0.2	0.2	0.1	0.1	0.1
Distributed income of equity investees	40.1	45.1	37.3	6.0	9.1	7.3
Less:						
Capitalized interest	(0.8)	(2.9)	(3.3)	(0.2)	(0.2)	(2.0)
Minority interest	(1.3)	(2.5)	(2.3)	(1.2)	(0.1)	(0.5)
Total Earnings	$132.9	$319.5	$274.2	$136.2	$24.9	$79.5
Fixed charges:						
Interest expense	68.2	49.6	33.3	16.4	15.1	25.7
Capitalized interest	0.8	2.9	3.3	0.2	0.2	2.0
Interest portion of rental expense	4.6	7.8	7.1	6.9	6.2	9.9
Total	$73.6	$60.3	$43.7	$23.5	$21.5	$37.6
Ratio of Earnings to Fixed charges	1.81x	5.30x	6.27x	5.80x	1.16x	2.11x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items.

Add the following, as applicable: consolidated pre-tax income before minority interest and income or loss from equity investees; fixed charges; amortization of capitalized interest; distributed income of equity investees; and our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the total of the added items, subtract the following, as applicable: interest capitalized; preference security dividend requirements of consolidated subsidiaries; and minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expenses (equal to one-third of rental expense); and preference security dividend requirements of consolidated subsidiaries.

Computation of Ratio of Earnings to Fixed Charges
for the nine months ended September 30, 2002 and each of the five years ended
December 31, 2001, 2000, 1999, 1998 and 1997 for Enterprise Products Operating L.P.
(dollars in millions)

	Nine Months Ended Sept. 30,	For the Year Ended December 31,				
	2002	2001	2000	1999	1998	1997
Income (loss) before minority interest, taxes and equity investments	$21.5	$219.5	$199.1	$108.4	$(5.5)	$37.0
Add:						
Fixed charges	73.6	60.3	43.7	23.5	21.5	37.6
Amortization of capitalized interest	0.2	0.2	0.2	0.1	0.1	0.1
Distributed income of equity investees	40.1	45.1	37.3	6.0	9.1	7.3
Less:						
Capitalized interest	(0.8)	(2.9)	(3.3)	(0.2)	(0.2)	(2.0)
Minority interest	(1.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Total Earnings	$133.5	$322.1	$276.9	$137.7	$24.9	$79.9
Fixed charges:						
Interest expense	68.2	49.6	33.3	16.4	15.1	25.7
Capitalized interest	0.8	2.9	3.3	0.2	0.2	2.0
Interest portion of rental expense	4.6	7.8	7.1	6.9	6.2	9.9
Total	$73.6	$60.3	$43.7	$23.5	$21.5	$37.6
Ratio of Earnings to Fixed charges	1.84x	5.34x	6.34x	5.86x	1.16x	2.13x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items.

Add the following, as applicable: consolidated pre-tax income before minority interest and income or loss from equity investees; fixed charges; amortization of capitalized interest; distributed income of equity investees; and our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the total of the added items, subtract the following, as applicable: interest capitalized; preference security dividend requirements of consolidated subsidiaries; and minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expenses (equal to one-third of rental expense); and preference security dividend requirements of consolidated subsidiaries.