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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2003

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

333 Clay Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 646-4100
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

At August 5, 2003, there were outstanding 40,885,939 Common Units, 1,307,190 Class B Common Units and 10,029,619 Subordinated Units.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except per unit data)

	June 30, 2003	December 31, 2002
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5,570	$ 3,501
Accounts receivable, net	429,417	499,909
Inventory	41,940	81,849
Other current assets	20,193	17,676
Total current assets	497,120	602,935
PROPERTY AND EQUIPMENT	1,170,235	1,030,303
Accumulated depreciation	(99,896)	(77,550)
	1,070,339	952,753
OTHER ASSETS		
Pipeline linefill	94,161	62,558
Other, net	48,801	48,329
Total assets	$1,710,421	$1,666,575
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 502,717	$ 488,922
Due to related parties	25,820	23,301
Short-term debt	17,978	99,249
Other current liabilities	14,409	25,777
Total current liabilities	560,924	637,249
LONG-TERM LIABILITIES		
Long-term debt under credit facilities, including current maturities of $10,000 and $9,000, respectively	326,865	310,126
Senior notes, net of unamortized discount of $370 and $390, respectively	199,630	199,610
Other long-term liabilities and deferred credits	22,207	7,980
Total liabilities	1,109,626	1,154,965
COMMITMENTS AND CONTINGENCIES (NOTE 7)		
PARTNERS' CAPITAL		
Common unitholders (40,885,939 and 38,240,939 units outstanding at June 30, 2003, and December 31, 2002, respectively)	605,009	524,428
Class B common unitholder (1,307,190 units outstanding at each date)	19,043	18,463
Subordinated unitholders (10,029,619 units outstanding at each date)	(42,653)	(47,103)
General partner	19,396	15,822
Total partners' capital	600,795	511,610
	$1,710,421	$1,666,575

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
	(unaudited)			
REVENUES	$2,709,189	$1,985,347	$5,991,097	$3,530,670
COST OF SALES AND OPERATIONS (excluding depreciation)	2,653,884	1,943,640	5,878,240	3,450,575
Gross margin (excluding depreciation)	55,305	41,707	112,857	80,095
EXPENSES				
General and administrative	12,161	11,119	25,233	21,877
Depreciation-operations	9,653	6,075	18,981	11,983
Depreciation and amortization-general and administrative	1,652	1,102	3,195	2,161
Total expenses	23,466	18,296	47,409	36,021
OPERATING INCOME	31,839	23,411	65,448	44,074
OTHER INCOME/(EXPENSE)				
Interest expense (net of $244 and $356 capitalized for the three month periods, respectively, and $296 and $458 capitalized for the six month periods, respectively)	(8,532)	(6,354)	(17,686)	(12,807)
Interest and other income (expense), net	91	(106)	(13)	(35)
NET INCOME	$ 23,398	$ 16,951	$ 47,749	$ 31,232
NET INCOME—LIMITED PARTNERS	$ 21,690	$ 15,902	$ 44,566	$ 29,356
NET INCOME—GENERAL PARTNER	$ 1,708	$ 1,049	$ 3,183	$ 1,876
BASIC AND DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.42	$ 0.37	$ 0.87	$ 0.68
WEIGHTED AVERAGE UNITS OUTSTANDING	52,223	43,253	51,200	43,253

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Six Months Ended June 30,	
	2003	2002
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 47,749	$ 31,232
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization	22,176	14,144
Change in derivative fair value	(1,155)	1,718
Changes in assets and liabilities, net of acquisitions:		
Accounts receivable and other	52,170	(139,534)
Inventory	41,015	122,599
Pipeline linefill	(28,478)	—
Accounts payable and other current liabilities	35,718	82,214
Settlement of environmental indemnities	4,600	—
Due to related parties	2,292	5,485
Net cash provided by operating activities	176,087	117,858
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(79,616)	(30,279)
Additions to property and equipment	(37,492)	(20,847)
Proceeds from sales of assets	5,790	987
Other investing activities	232	—
Net cash used in investing activities	(111,086)	(50,139)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings on long-term revolving credit facility	29,089	36,760
Net repayments on short-term letter of credit and hedged inventory facility	(90,178)	(53,635)
Principal payments on senior secured term loan	(7,000)	(1,000)
Cash paid in connection with financing arrangements	(60)	(654)
Net proceeds from the issuance of common units	63,895	—
Distributions paid to unitholders and general partner	(58,772)	(47,041)
Net cash used in financing activities	(63,026)	(65,570)
Effect of translation adjustment on cash	94	132
Net increase in cash and cash equivalents	2,069	2,281
Cash and cash equivalents, beginning of period	3,501	3,511
Cash and cash equivalents, end of period	$ 5,570	$ 5,792
Cash paid for interest, net of amounts capitalized	$ 19,092	$ 14,427

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(in thousands)

	Common Unitholders		Class B Common Unitholder		Subordinated Unitholders		General Partner	Total Partners' Capital
	Units	Amounts	Units	Amounts	Units	Amounts	Amount	Amount
				(unaudited)				
Balance at December 31, 2002	38,241	$ 524,428	1,307	$ 18,463	10,030	$ (47,103)	$ 15,822	$ 511,610
Issuance of common units	2,645	62,556	—	—	—	—	1,339	63,895
Distributions	—	(43,040)	—	(1,422)	—	(10,907)	(3,403)	(58,772)
Other comprehensive income	—	26,364	—	864	—	6,630	2,455	36,313
Net income	—	34,701	—	1,138	—	8,727	3,183	47,749
Balance at June 30, 2003	40,886	$ 605,009	1,307	$ 19,043	10,030	$ (42,653)	$ 19,396	$ 600,795

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in thousands)

Statements of Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(unaudited)			
Net income	$23,398	$16,951	$47,749	$31,232
Other comprehensive income	16,390	13,899	36,313	10,948
Comprehensive income	$39,788	$30,850	$84,062	$42,180

Statement of Changes in Accumulated Other Comprehensive Income

	Net Deferred Gain (Loss) on Derivative Instruments	Currency Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2002	$ (8,207)	$ (6,219)	$ (14,426)
Current period activity			
Reclassification adjustments for settled contracts	(2,028)	—	(2,028)
Changes in fair value of outstanding hedge positions	2,743	—	2,743
Currency translation adjustment	—	35,598	35,598
Total period activity	715	35,598	36,313
Balance at June 30, 2003	$ (7,492)	$ 29,379	$ 21,887

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1—Organization and Accounting Policies

Plains All American Pipeline, L.P., is a publicly traded Delaware limited partnership (the "Partnership") formed in 1998 and is engaged in interstate and intrastate marketing, transportation and terminalling of crude oil and liquified petroleum gas ("LPG"). Our operations are conducted directly and indirectly through Plains Marketing, L.P., All American Pipeline, L.P. and Plains Marketing Canada, L.P., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of June 30, 2003, and December 31, 2002, (ii) the results of our consolidated operations for the three months and six months ended June 30, 2003 and 2002, (iii) consolidated cash flows for the six months ended June 30, 2003 and 2002, (iv) consolidated changes in partners' capital for the six months ended June 30, 2003, (v) consolidated comprehensive income for the three months and six months ended June 30, 2003 and 2002, and (vi) changes in consolidated accumulated other comprehensive income for the six months ended June 30, 2003. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. All adjustments, consisting only of normal recurring adjustments, that in the opinion of management were necessary for a fair statement of the results for the interim periods, have been reflected. All significant intercompany transactions have been eliminated. Certain reclassifications are made to prior period amounts to conform to current period presentation. The results of operations for the three months and six months ended June 30, 2003 should not be taken as indicative of the results to be expected for the full year. The consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2002 Annual Report on Form 10-K.

Note 2—Acquisitions and Dispositions

The following acquisitions made in 2003 did not have a material effect on either our financial position, results of operations or cash flows, either individually or in the aggregate. The cash portion of these acquisitions was funded from cash on hand and borrowings under our revolving credit facility. The entire purchase price of each acquisition was allocated to property and equipment.

Iraan to Midland Pipeline System

In June 2003, the Partnership acquired the Iraan to Midland Pipeline System from a unit of Marathon Ashland Petroleum LLC ("MAP") for aggregate consideration of approximately $17.4 million. The Iraan to Midland Pipeline System is a 16-inch, 95-mile mainline crude oil pipeline that originates in Iraan, Texas and terminates in Midland, Texas. At Midland, the system has the ability to deliver crude oil to our Basin Pipeline System and to the Mesa Pipeline System. In 2002, the Iraan to Midland Pipeline System delivered approximately 21,000 barrels per day of crude oil. The effective date of the transaction is June 30, 2003 and the results of operations and assets have been included in our consolidated financial statements and our pipeline operations since that time. The aggregate purchase price included $13.6 million in cash, approximately $3.6 million associated with the satisfaction of outstanding claims for accounts receivable and inventory balances, and approximately $0.2 million of estimated transaction costs.

South Louisiana Assets

In June 2003, we completed the acquisition of a package of terminalling and gathering assets from El Paso Corporation for approximately $10.8 million, including transaction costs. These assets are located in southern Louisiana and include various interests in five pipelines and gathering systems and two terminal facilities. These assets complement our existing activities in south Louisiana and we believe will help leverage our exposure to the growing volume of crude oil and condensate production from the Gulf of Mexico. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since June 1, 2003.

Alto Storage Facility

In June 2003, we completed the acquisition of an underground LPG storage facility from Ohio-Northwest Development, Inc. for approximately $8.1 million, including transaction costs and assumed liabilities. The underground facility, which is located in Alto, Michigan, is currently capable of storing over 38 million gallons of LPG. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our gathering, marketing, terminalling and storage operations segment since June 1, 2003. This storage facility further supports the expansion of our LPG business in Canada and the northern tier of the United States.

Mesa Pipeline System

In May 2003, we completed the acquisition of an 8.8% undivided interest in the Mesa Pipeline System from Unocal Corporation for approximately $2.9 million, including transaction costs. The system is located in the Permian Basin in West Texas, originating at Midland and terminating at Colorado City, and serves to complement our Basin Pipeline System. As a result of this transaction, we will have access to a net capacity of approximately 28,000 barrels of crude oil per day on the system. This system is operated by an affiliate of ChevronTexaco. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since May 5, 2003.

Iatan Gathering System

In March 2003, we completed the acquisition of a West Texas crude oil gathering system from Navajo Refining Company, L.P. for approximately $24.3 million, including transaction costs. The assets are located in the Permian Basin in West Texas and consist of approximately 315 miles of active crude oil gathering lines. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2003.

Red River Pipeline System

In February 2003, we completed the acquisition of a 347-mile crude oil pipeline from BP Pipelines (North America) Inc. for approximately $19.3 million, including transaction costs. The system originates at Sabine in East Texas and terminates near Cushing, Oklahoma. The system also includes approximately 695,000 barrels of crude oil storage capacity. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since February 1, 2003. This pipeline complements our existing assets in East Texas and, upon completion of a planned interconnect, will provide another direct mainline connection to our Cushing Terminal.

Shutdown of Rancho Pipeline System

We acquired the Rancho Pipeline System in conjunction with the acquisition of several other West Texas assets from Shell Pipeline Company, LP and Equilon Enterprises, LLC in August of 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with Statement of Financial Accounting Standards ("SFAS") No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred all of our ownership interest in approximately 240 miles of the total 458 miles of the pipeline in exchange for $4 million and approximately 500,000 barrels of crude oil tankage in West Texas. The balance of the pipeline system is subject to an option to purchase by a third party. We are currently in discussions for the pipe to be salvaged in the event that the option to purchase is not exercised. No gain or loss has been recorded on the shutdown of the Rancho System or these transactions.

Note 3—Accounts Receivable

Accounts receivable included in the consolidated balance sheets are reflected net of our allowance for doubtful accounts. We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy.

At June 30, 2003 approximately 98% of our net accounts receivable classified as current were less than 60 days past the scheduled invoice date. Our allowance for doubtful accounts receivable classified as current totaled $3.2 million, representing 27% of all receivable balances greater than 60 days past the scheduled invoice date. At June 30, 2003 approximately $0.9 million of net accounts receivable were classified as long-term. Our allowance for doubtful accounts receivable classified as long-term totaled $5.0 million, representing 85% of all long-term receivable balances.

Note 4—Debt

During the six months ended June 30, 2003 we had net borrowings under our revolving credit facilities of approximately $29.1 million, including borrowings for a scheduled maturity payment of $7.0 million on our senior secured term loan. At June 30, 2003, we have classified $10 million of term loan maturities due in the next twelve months as long term due to our intent and ability to refinance those maturities using the revolving credit facilities. At June 30, 2003 our total long-term debt balance was approximately $526.5 million and total availability under our long-term revolving credit facilities was approximately $403.1 million (net of $10.0 million to refinance term loan maturities due in the next twelve months).

Note 5—Partners' Capital and Distributions

Distributions

On July 25, 2003, we declared a cash distribution of $0.55 per unit on our outstanding common units, Class B common units and subordinated units. The distribution is payable on August 14, 2003, to unitholders of record on August 4, 2003, for the period April 1, 2003, through June 30, 2003. The total distribution to be paid is approximately $30.6 million, with approximately $23.2 million to be paid to our common unitholders, $5.5 million to be paid to our subordinated unitholders and $0.6 million and $1.3 million to be paid to our general partner for its general partner and incentive distribution interests, respectively. The distribution is in excess of the minimum quarterly distribution specified in the partnership agreement.

On April 24, 2003, we declared a cash distribution of $0.55 per unit on our outstanding common units, Class B common units and subordinated units. The distribution was paid on May 15, 2003, to unitholders of record on

May 5, 2003, for the period January 1, 2003, through March 31, 2003. The total distribution paid was approximately $30.6 million, with approximately $23.2 million paid to our common unitholders, $5.5 million paid to our subordinated unitholders and $0.6 million and $1.3 million paid to our general partner for its general partner and incentive distribution interests, respectively. The distribution was in excess of the minimum quarterly distribution specified in the partnership agreement.

On January 24, 2003, we declared a cash distribution of $0.5375 per unit on our outstanding common units, Class B common units and subordinated units. The distribution was paid on February 14, 2003, to unitholders of record on February 4, 2003, for the period October 1, 2002, through December 31, 2002. The total distribution paid was approximately $28.2 million, with approximately $21.2 million paid to our common unitholders, $5.4 million paid to our subordinated unitholders and $0.6 million and $1.0 million paid to our general partner for its general partner and incentive distribution interests, respectively. The distribution was in excess of the minimum quarterly distribution specified in the partnership agreement.

Equity Offering

In March 2003, we completed a public offering of 2,645,000 common units for $24.80 per unit. The offering resulted in cash proceeds of approximately $65.6 million from the sale of the units and approximately $1.3 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $3.0 million. Net proceeds of approximately $63.9 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

Note 6—Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk.

Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. The June 30, 2003, balance sheet includes assets of $17.5 million ($13.5 million current), liabilities of $22.9 million ($6.5 million current) and related unrealized net losses deferred to Other Comprehensive Income ("OCI") of $7.5 million. Our hedge-related assets and liabilities are included in other current and non-current assets and liabilities in the consolidated balance sheet. In addition, revenues for the six months ended June 30, 2003, included a noncash gain of $1.1 million ($2.1 million noncash gain before the reversal of the prior period fair value adjustment related to contracts that settled during the current period) resulting from (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

(unaudited)

As of June 30, 2003, the total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the six months ended June 30, 2003 and 2002, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Of the $7.5 million net loss deferred to OCI at June 30, 2003, a gain of $4.6 million will be reclassified to earnings in the next twelve months and the remainder by May 2006. Since these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the New York Mercantile Exchange and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS No. 133 “Accounting for Derivative Instruments and Hedging Activities,” these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of our commodity price risk derivative instruments qualify for hedge accounting as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or cost of sales and operations in the periods during which the underlying physical transactions occur. We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. At June 30, 2003 and 2002, there was a gain of $6.3 million and a gain of $0.1 million, respectively, deferred in OCI related to our commodity price risk activities. The amount included in earnings due to changes in the fair value of derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective for the six months ended June 30, 2003 and 2002, was a gain of $1.3 million and a loss of $1.7 million, respectively.

Controlled Trading Program

From time to time, we experience net unbalanced positions as a result of production and delivery variances associated with our lease purchase activities. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to 500,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues. There were no open positions under this program at June 30, 2003. The realized earnings impact related to these derivatives for the six months ended June 30, 2003 and 2002 was a loss of $0.1 million and $0.2 million, respectively.

Interest Rate Risk Hedging

We utilize various products, such as interest rate swaps, collars and treasury locks, to hedge interest obligations on specific debt issuances, including anticipated debt issuances. During the first quarter of 2003, we converted a $50.0 million treasury lock into a 10-year LIBOR-based swap that becomes effective in March 2004, as discussed below, contemporaneously with the expiration of an existing $50.0 million LIBOR-based swap. The instruments outstanding at June 30, 2003, consist of three separate interest rate swaps with an aggregate notional principal amount of $100.0 million outstanding at any one time. The interest rate swaps are based on LIBOR rates and provide for a LIBOR rate of 5.1% for a $50.0 million notional principal amount expiring October 2006, a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004 and a LIBOR rate of 5.8% for a $50.0 million notional principal amount that commences in March 2004 and expires in March 2014. All of these instruments are placed with what we believe are large creditworthy financial institutions. Interest on the underlying debt is based on LIBOR plus a margin.

These instruments qualify for hedge accounting as cash flow hedges in accordance with SFAS 133. The effective portion of changes in fair values of these hedges is recorded in OCI until the related hedged item impacts earnings. At June 30, 2003 and 2002, there were losses of $13.4 million and $3.9 million, respectively, deferred in OCI related to our interest rate risk activities. For the six months ended June 30, 2003 and 2002, there were no amounts recognized into earnings related to hedge ineffectiveness.

At June 30, 2003, our weighted average interest rate, excluding non-use and facilities fees, was approximately 5.7%. This rate is based on our June 30, 2003 debt balances and floating rate indices, our credit spread under our credit facilities and the combination of our fixed rate debt and current interest rate hedges. We have locked-in interest rates (excluding the credit spread under the credit facilities) for approximately 57% of our total long-term debt through October 2006, and 47% for the period from October 2006 through September 2012.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at June 30, 2003, $8.0 million of our long-term debt was denominated in Canadian dollars ($10.8 million CAD based on a Canadian-U.S. dollar exchange rate of 1.35).

At June 30, 2003, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U.S. quarterly during 2003 (based on a Canadian-U.S. dollar exchange rate of 1.54). At June 30, 2003, we also had cross currency swap contracts for an aggregate notional principal amount of $23.0 million, effectively converting this amount of our senior secured term loan to $35.6 million of Canadian dollar debt (based on a Canadian-U.S. dollar exchange rate of 1.55). The terms of this contract mirror the term loan, matching the amortization schedule and final maturity in May 2006. All of these instruments are placed with what we believe are large creditworthy financial institutions.

The forward exchange contracts and forward extra option contracts qualify for hedge accounting as cash flow hedges, in accordance with SFAS 133. Such derivative activity resulted in a loss of $0.4 million deferred in OCI at June 30, 2003 and a nominal amount at June 30, 2002. For the six months ended June 30, 2003 and 2002, there were no amounts recognized into earnings related to hedge ineffectiveness. The cross currency swaps qualify for hedge accounting as fair value hedges, also in accordance with SFAS 133. Therefore, the change in the fair value of these instruments is recognized currently in earnings. The earnings impact related to our cross currency swaps was a loss of $0.2 million for the six months ended June 30, 2003 and a nominal amount for the six months ended June 30, 2002.

Note 7—Commitments and Contingencies

Litigation

We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. We do not believe that the outcome of these other legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

(unaudited)

Indemnities

In November, 2002, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We are party to various contracts entered into in the ordinary course of business that contain indemnity provisions pursuant to which we indemnify the counterparties against various expenses. Our indemnity obligations are contingent upon the occurrence of events or circumstances specified in the contracts. No such events or circumstances have occurred at this time, and we do not consider our liability under such indemnity provisions, individually or in the aggregate, to be material to our financial position or results of operations.

Environmental

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. Our total environmental reserve, including the reserve associated with the assets that are subject to this agreement, approximated $6.0 million at June 30, 2003. We believe this environmental reserve is adequate. However, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

Contingent Equity Issuance

In connection with the CANPET acquisition in July 2001, approximately $26.5 million Canadian dollars of the purchase price, payable in common units, was deferred subject to various performance objectives being met. If these objectives are met as of December 31, 2003, the deferred amount is payable on April 30, 2004. The number of common units issued in satisfaction of the deferred payment will depend upon the average trading price of our common units for a ten day trading period prior to the payment date and the Canadian and U.S. dollar exchange rate on the payment date. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. At our option, the deferred payment may be paid in cash rather than the issuance of units. We believe that it is probable that the objectives will be met and the deferred amount will be paid in April 2004, however, it is not determinable beyond a reasonable doubt. Assuming the tests are met as of December 31, 2003, and the entire obligation is satisfied with common units, based on the foreign exchange rate and unit price in effect at June 30, 2003, (1.35 Canadian to U.S. dollar exchange rate and $30.84 per unit price) approximately 650,000 units would be issued.

Other

Since the terrorist attacks of September 11, 2001, the United States Government has issued numerous warnings that energy assets (including our nation's pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The Department of Transportation ("DOT") has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how the DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT "critical facilities" and therefore potential terrorist targets. In compliance with DOT guidance, we performed vulnerability analyses on our critical facilities and have instituted, or will institute as appropriate, any indicated security measures or procedures that are not already in place. The Transportation Safety Administration (an agency of the Department of Homeland Security, which is in the transitional phase of assuming responsibility from the DOT) may issue additional guidelines. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Note 8—Operating Segments

Our operations consist of two operating segments: (1) our Pipeline Operations through which we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities; and (2) our Gathering, Marketing, Terminalling and Storage Operations through which we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. We evaluate segment performance based on (i) gross margin (excluding depreciation), (ii) gross profit (excluding depreciation), which is gross margin (excluding depreciation) less general and administrative expenses and (iii) on an annual basis, maintenance capital. Maintenance capital consists of expenditures required to maintain the existing operating capacity of partially or fully depreciated assets or extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(unaudited)

	Pipeline	Gathering Marketing, Terminalling & Storage	Total
		(in millions)	
Three Months Ended June 30, 2003			
Revenues:			
External Customers	$ 143.3	$ 2,565.9	$ 2,709.2
Intersegment (1)	12.5	0.3	12.8
Total revenues of reportable segments	$ 155.8	$ 2,566.2	$ 2,722.0
Gross margin (excluding depreciation)	$ 28.7	$ 26.6	$ 55.3
General and administrative expenses (2)	4.5	7.7	12.2
Gross profit (excluding depreciation)	$ 24.2	$ 18.9	$ 43.1
Noncash SFAS 133 impact (3)	$ —	$ 0.2	$ 0.2
Maintenance capital	$ 2.4	$ 0.2	$ 2.6
Three Months Ended June 30, 2002			
Revenues:			
External Customers	$ 111.4	$ 1,873.9	$ 1,985.3
Intersegment (1)	3.7	—	3.7
Total revenues of reportable segments	$ 115.1	$ 1,873.9	$ 1,989.0
Gross margin (excluding depreciation)	$ 18.8	$ 22.9	$ 41.7
General and administrative expenses (2)	3.3	7.8	11.1
Gross profit (excluding depreciation)	$ 15.5	$ 15.1	$ 30.6
Noncash SFAS 133 impact (3)	$ —	$ 1.1	$ 1.1
Maintenance capital	$ 0.9	$ 0.1	$ 1.0
Six Months Ended June 30, 2003			
Revenues:			
External Customers	$ 302.3	$ 5,688.8	$ 5,991.1
Intersegment (1)	22.5	0.5	23.0
Total revenues of reportable segments	$ 324.8	$ 5,689.3	$ 6,014.1
Gross margin (excluding depreciation)	$ 53.5	$ 59.4	$ 112.9
General and administrative expenses (2)	9.1	16.1	25.2
Gross profit (excluding depreciation)	$ 44.4	$ 43.3	$ 87.7
Noncash SFAS 133 impact (3)	$ —	$ 1.1	$ 1.1
Maintenance capital	$ 3.8	$ 0.4	$ 4.2

Table continued on following page

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

(unaudited)

	Pipeline	Gathering Marketing, Terminalling & Storage	Total
		(in millions)	
Six Months Ended June 30, 2002			
Revenues:			
External Customers	$ 196.8	$ 3,333.9	$ 3,530.7
Intersegment [(1)]	6.8	—	6.8
Total revenues of reportable segments	$ 203.6	$ 3,333.9	$ 3,537.5
Gross margin (excluding depreciation)	$ 37.3	$ 42.8	$ 80.1
General and administrative expenses [(2)]	6.6	15.3	21.9
Gross profit (excluding depreciation)	$ 30.7	$ 27.5	$ 58.2
Noncash SFAS 133 impact [(3)]	$ —	$ (1.7)	$ (1.7)
Maintenance capital	$ 2.2	$ 0.6	$ 2.8

(1) Intersegment sales are based on published tariff rates or contracted amounts at market prices.
(2) General and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A by segment for the three and six month periods ended June 30, 2002, to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.
(3) Amounts related to SFAS 133 are included in revenues, gross margin (excluding depreciation) and gross profit (excluding depreciation). When we internally evaluate our results, we exclude the noncash, mark-to-market impact of SFAS 133.

Note 9—Recent Accounting Pronouncements

In May 2003, the FASB issued SFAS No. 150 “Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity.” SFAS 150 establishes standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. Financial instruments that fall within the scope of SFAS 150 will be classified as liabilities (or assets in some circumstances). In many cases, these financial instruments were previously classified as equity. This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We do not have any financial instruments that fall under the scope of this statement and do not believe that the adoption of SFAS 150 will have a material effect on either our financial position, results of operations or cash flows.

In May 2003, the FASB issued SFAS No. 149 “Amendment of Statement 133 on Derivative Instruments and Hedging Activities.” SFAS 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS 133. This Statement is effective for contracts entered into or modified after June 30, 2003 (except for certain exceptions) and for hedging relationships designated after June 30, 2003. We do not believe its adoption will have a material effect on either our financial position, results of operations or cash flows.

In May 2003, the Emerging Issues Task Force (“EITF”) reached consensus on certain issues in EITF Issue No. 01-08, “Determining Whether an Arrangement Contains a Lease.” The consensus provides guidance as to whether an arrangement contains a lease within the scope of SFAS No. 13, “Accounting For Leases.” EITF 01-08 is effective for arrangements entered into, modified, or acquired in a business combination after June 30, 2003. We do not believe its adoption will have a material impact on either our financial position, results of operations or cash flows.

In December 2002, the FASB issued SFAS No. 148 “Accounting for Stock-Based Compensation—Transition and Disclosure.” SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 in both annual and interim financial statements. SFAS 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. Our general partner has equity-based employee compensation plans. These plans are accounted for under the fair value based method as described in SFAS 123. Therefore, the adoption of this statement did not have a material effect on either our financial position, results of operations, cash flows or disclosure requirements.

In June 2002, the FASB issued SFAS No. 146 “Accounting for Costs Associated with Exit or Disposal Activities.” SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the obligation is incurred rather than at the date of the exit plan. This Statement is effective for exit or disposal activities that are initiated after December 31, 2002. We have not initiated any material exit or disposal activities that are subject to this statement and do not believe that the adoption of SFAS 146 will have a material effect on either our financial position, results of operations or cash flows.

In June 2001, the FASB issued SFAS No. 143 “Asset Retirement Obligations.” SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is retired. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we determine the settlement dates. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows. See Note 2 for the accounting treatment of the shutdown of the Rancho Pipeline System.

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

Overview

Plains All American Pipeline, L.P., is a publicly traded Delaware limited partnership (the "Partnership") formed in 1998 and is engaged in interstate and intrastate marketing, transportation and terminalling of crude oil and liquified petroleum gas ("LPG"). Our operations are conducted directly and indirectly through Plains Marketing, L.P., All American Pipeline, L.P. and Plains Marketing Canada, L.P., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

During the first quarter of 2003, new Securities and Exchange Commission regulations regarding the use of non-GAAP financial measures became effective. As a result of our efforts to comply with these new regulations, we have made certain changes to the content and presentation of information in Management's Discussion and Analysis of Financial Condition and Results of Operations. Although not excluded here, when we internally evaluate our results for performance against expectations, public guidance and trend analysis, we exclude the noncash, mark-to-market impact of Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" resulting from (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. The majority of these instruments serve as economic hedges that offset future physical positions not reflected in current results. Therefore, the SFAS 133 adjustment to net income is not a complete depiction of the economic substance of the transaction, as it only represents the derivative side of these transactions and does not take into account the offsetting physical position. In addition, the impact will vary from quarter to quarter based on market prices at the end of the quarter, which are impossible for us to control or forecast.

Internally, we also exclude from our operating results the impact of other items we consider to impact comparability between periods. To comply with the new regulations, we have omitted certain adjustments and reconciliations related to these items that have been presented in the past. We have also changed the format of certain tables presented in the discussion of our results of operations. In addition, certain reclassifications have been made to prior period amounts to conform to current period presentation. Where appropriate, we have noted that reported results include the effects of items we consider to impact comparability between periods. Overall, we believe the discussion and presentation provides an accurate and thorough analysis of our results of operations and financial condition. Additionally, we maintain on our website (www.paalp.com) a reconciliation of all non-GAAP financial information that we disclose to the most comparable GAAP measures. To access the information, investors should click on the "Non-GAAP Reconciliation" link on our home page.

Acquisitions

We completed several acquisitions during 2002 and 2003 that have impacted the results of operations and liquidity discussed herein. The cash portion of these acquisitions was funded from cash on hand and borrowings under our revolving credit facility. The entire purchase price of each acquisition was allocated to property and equipment. These acquisitions are discussed below and our ongoing acquisition activity is discussed further in "Liquidity and Capital Resources."

Iraan to Midland Pipeline System

In June 2003, the Partnership acquired the Iraan to Midland Pipeline System from a unit of Marathon Ashland Petroleum LLC ("MAP") for aggregate consideration of approximately $17.4 million. The Iraan to Midland Pipeline System is a 16-inch, 95-mile mainline crude oil pipeline that originates in Iraan, Texas and terminates in Midland, Texas. At Midland, the system has the ability to deliver crude oil to our Basin Pipeline System and to the Mesa Pipeline System. In 2002, the Iraan to Midland Pipeline System delivered approximately 21,000 barrels per day of crude oil. The effective date of the transaction is June 30, 2003, and the results of operations and assets from this acquisition have been included in our pipeline operations segment since that time.

South Louisiana Assets

In June 2003, we completed the acquisition of a package of terminalling and gathering assets from El Paso Corporation for approximately $10.8 million, including transaction costs. These assets are located in southern Louisiana and include various interests in five pipelines and gathering systems and two terminal facilities. These assets complement our existing activities in south Louisiana and we believe will help leverage our exposure to the growing volume of crude oil and condensate production from the Gulf of Mexico. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since June 1, 2003.

Alto Storage Facility

In June 2003, we completed the acquisition of an underground LPG storage facility from Ohio-Northwest Development, Inc. for approximately $8.1 million, including transaction costs and assumed liabilities. The underground facility, which is located in Alto, Michigan, currently is capable of storing over 38 million gallons of LPG. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our gathering, marketing, terminalling and storage operations segment since June 1, 2003. This storage facility further supports the expansion of our LPG business in Canada and the northern tier of the United States.

Mesa Pipeline System

In May 2003, we completed the acquisition of an 8.8% undivided interest in the Mesa Pipeline System from Unocal Corporation for approximately $2.9 million, including transaction costs. The system is located in the Permian Basin in West Texas, originating at Midland and terminating at Colorado City, and serves to complement our Basin Pipeline System. As a result of this transaction, we will have access to a net capacity of approximately 28,000 barrels of crude oil per day on the system. This system is operated by an affiliate of ChevronTexaco. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since May 5, 2003.

Iatan Gathering System

In March 2003, we completed the acquisition of a West Texas crude oil gathering system from Navajo Refining Company, L.P. for approximately $24.3 million, including transaction costs. The assets are located in the Permian Basin in West Texas and consist of approximately 315 miles of active crude oil gathering lines. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2003.

Red River Pipeline System

In February 2003, we completed the acquisition of a 347-mile crude oil pipeline from BP Pipelines (North America) Inc. for approximately $19.3 million in cash, including transaction costs. The system originates at Sabine in East Texas and terminates near Cushing, Oklahoma. The system also includes approximately 695,000 barrels of crude oil storage capacity. We plan to replace or refurbish approximately 32 miles of existing pipe on this pipeline and to build a twelve-mile extension of the system to connect to our terminal in Cushing. We estimate the total cost of the projects to be approximately $14.0 million, of which approximately $5.0 million will be spent in 2003 (approximately $1.7 million has been spent as of June 30, 2003) and approximately $9.0 million will be spent in 2004. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since February 1, 2003. This pipeline complements our existing assets in East Texas and, upon completion of the planned interconnect, will provide another direct mainline connection to our Cushing Terminal.

2002 Acquisitions

In August 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the “Shell acquisition”) for approximately $324 million. In March 2002, we acquired substantially all of the domestic crude oil gathering and marketing assets of Coast Energy Group and Lantern Petroleum, divisions of Cornerstone Propane Partners, L.P., (the “Cornerstone acquisition”) for approximately $8.3 million. In February 2002, we acquired an approximate 22% equity interest in Butte Pipeline Company (the “Butte acquisition”) for approximately $7.6 million.

Results of Operations

Our operations consist of two operating segments: (1) our Pipeline Operations, through which we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities; and (2) our Gathering, Marketing, Terminalling and Storage Operations, through which we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. We evaluate segment performance based on (i) gross margin (excluding depreciation), (ii) gross profit (excluding depreciation), which is gross margin (excluding depreciation) less general and administrative expenses and (iii) on an annual basis, maintenance capital. Maintenance capital consists of capital expenditures required to maintain the existing operating capacity of partially or fully depreciated assets or extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. For 2003, we have budgeted annual maintenance capital expenditures of $8.5 million. We monitor maintenance capital expenditures on an annual basis, since these capital projects can overlap quarters and may be impacted by weather, permitting and other non-controllable delays. Accordingly, no period by period analysis is provided, except on an annual basis.

Three Months Ended June 30, 2003 and 2002

For the three months ended June 30, 2003, we reported net income of $23.4 million on total revenues of $2.7 billion compared to net income for the same period in 2002 of $17.0 million on total revenues of $2.0 billion. Our net income includes gains of $0.2 million and $1.1 million related to SFAS 133 for the quarters ended June 30, 2003 and 2002, respectively. The following table reflects our results of operations for each segment:

	Pipeline	Gathering, Marketing, Terminalling & Storage	Total
		(in millions)	
Three Months Ended June 30, 2003 (1)			
Revenues	$155.8	$ 2,566.2	$ 2,722.0
Cost of sales and operations (excluding depreciation)	127.1	2,539.6	2,666.7
Gross margin (excluding depreciation)	28.7	26.6	55.3
General and administrative expenses (2)	4.5	7.7	12.2
Gross profit (excluding depreciation)	$ 24.2	$ 18.9	$ 43.1
Noncash SFAS 133 impact (3)	$ —	$ 0.2	$ 0.2
Maintenance capital	$ 2.4	$ 0.2	$ 2.6

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	Pipeline	Gathering, Marketing, Terminalling & Storage	Total
		(in millions)	
Three Months Ended June 30, 2002 (1)			
Revenues	$115.1	$ 1,873.9	$ 1,989.0
Cost of sales and operations (excluding depreciation)	96.3	1,851.0	1,947.3
Gross margin (excluding depreciation)	18.8	22.9	41.7
General and administrative expenses (2)	3.3	7.8	11.1
Gross profit (excluding depreciation)	$ 15.5	$ 15.1	$ 30.6
Noncash SFAS 133 impact (3)	$ —	$ 1.1	$ 1.1
Maintenance capital	$ 0.9	$ 0.1	$ 1.0

(1) Revenues and costs of sales and operations include intersegment amounts.
(2) General and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A by segment for the second quarter of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Amounts related to SFAS 133 are included in revenues, gross margin (excluding depreciation), and gross profit (excluding depreciation).

Pipeline Operations

As of June 30, 2003, we own and operate over 6,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third-party leases of pipeline capacity (tariff activities), as well as barrel exchanges and buy/sell arrangements (margin activities). We also use our pipelines in our merchant activities conducted under our gathering and marketing business. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The gross margin (excluding depreciation) generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable costs of operating the pipeline. Gross margin (excluding depreciation) from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Three months ended June 30,	
	2003	2002
Operating Results (in millions) (1)		
Tariff activities revenues	$ 38.3	$ 19.9
Margin activities revenues	117.5	95.2
Total pipeline operations revenues	155.8	115.1
Cost of sales and operations (excluding depreciation)	127.1	96.3
Gross Margin (excluding depreciation)	28.7	18.8
General and administrative expenses (2)	4.5	3.3
Gross Profit (excluding depreciation)	$ 24.2	$ 15.5
Maintenance capital	$ 2.4	$ 0.9

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	Three months ended June 30, 2003	2002
Average Daily Volumes (thousands of barrels per day) [(3)]		
Tariff activities		
All American	63	61
Basin	280	n/a
Other domestic	253	154
Canada	169	182
Total tariff activities	765	397
Margin activities	75	73
Total	840	470

(1) Revenues and cost of sales and operations include intersegment amounts.
(2) General and administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for the second quarter of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

Total average daily volumes transported were approximately 840,000 barrels per day and 470,000 barrels per day for the three months ended June 30, 2003 and 2002, respectively. As discussed above, we have completed a number of acquisitions during 2003 and 2002 that have impacted the results of operations herein. The following table reflects our total average daily volumes from our tariff activities by year of acquisition for comparison purposes:

	Three months ended June 30, 2003	2002
	(thousands of barrels per day)	
Tariff activities [(1)] [(2)]		
2003 acquisitions	52	—
2002 acquisitions	337	15
All other pipeline systems	376	382
Total tariff activities average daily volumes	765	397

(1) The 2003 acquisitions include the Red River pipeline system, the Iatan gathering system, the Mesa pipeline system and the South Louisiana assets. The 2002 acquisitions include the pipeline systems included in the Shell acquisition and the Butte pipeline system.
(2) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

Average daily volumes from our tariff activities were approximately 765,000 barrels per day compared to approximately 397,000 barrels per day for the prior year quarter. Approximately 374,000 barrels per day of the increase in the current year quarter is due to volumes transported on the pipelines acquired in 2003 and 2002, including approximately 322,000 on the assets acquired in the Shell acquisition. Volumes on all other pipeline systems decreased by approximately 6,000 barrels per day. The decrease is primarily related to a 13,000 barrel per day decrease in volumes from our Canadian pipelines. This decrease primarily resulted from refinery turnarounds, which limited throughput on our Milk River system (one of our lowest per barrel tariff pipelines) during the 2003 period. This decrease was partially offset by increases in our All American tariff volumes attributable to California outer continental shelf ("OCS") production, coupled with increases in our West Texas gathering volumes.

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Total revenues from our pipeline operations were approximately $155.8 million and $115.1 million for the three months ended June 30, 2003 and 2002, respectively. The increase in revenues was primarily related to our margin activities, which increased by approximately $22.3 million in the second quarter of 2003. This increase was related to higher average prices on our margin activity on our San Joaquin Valley gathering system in the 2003 period as compared to the 2002 period, coupled with higher volumes on our buy/sell arrangements in the current period. However, this business is a margin business and although revenues and cost of sales are impacted by the absolute level of crude oil prices, there is a limited impact on gross margin.

Revenues from our tariff activities increased approximately $18.4 million. The following table reflects our revenues from our tariff activities by year of acquisition for comparison purposes:

	Three months ended June 30,	
	2003	2002
	(in millions)	
Tariff activities revenues (1) (2)		
2003 acquisitions	$ 2.8	$ —
2002 acquisitions	13.7	0.1
All other pipeline systems	21.8	19.8
Total tariff activities	$38.3	$19.9

(1) Revenues include intersegment amounts.
(2) The 2003 acquisitions include the Red River pipeline system, the Iatan gathering system, the Mesa pipeline system and the South Louisiana assets. The 2002 acquisitions include the pipeline systems included in the Shell acquisition and the Butte pipeline system.

Total revenues from our tariff activities were approximately $38.3 million and $19.9 million for the three months ended June 30, 2003 and 2002, respectively. The increase in the second quarter of 2003 is predominately related to the inclusion of $16.5 million of revenues from the businesses acquired in 2003 and 2002, including approximately $13.7 million from the assets acquired in the Shell acquisition. Revenues from all other pipeline systems increased approximately $2.0 million. The increase in revenues from all other pipeline systems in 2003 resulted primarily from our Canadian operations. Despite lower volumes, Canadian revenues increased approximately $1.3 million in the 2003 period primarily due to higher tariffs and a $0.9 million favorable exchange rate impact. The favorable exchange rate impact has resulted from a decrease in the Canadian to U.S. dollar exchange rate to an average rate of 1.40 for the three months ended June 30, 2003, from an average rate of 1.55 for the three months ended June 30, 2002. Tariff revenue from all other systems also increased related to higher revenues from the All American System, on which we receive the highest per barrel tariffs among our pipeline systems and higher revenues from the West Texas gathering system.

As a result of these factors, pipeline operations gross margin (excluding depreciation) increased 53% to approximately $28.7 million for the quarter ended June 30, 2003, from $18.8 million for the prior year period, an increase of approximately $9.9 million. Such results incorporate an increase in operating expenses to $14.3 million in the 2003 period from $6.8 million in the 2002 period related to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher utility costs. In addition, gross margin (excluding depreciation) includes a $0.6 million favorable impact resulting from the decrease in the average Canadian dollar to U.S. dollar exchange rate for the 2003 period as compared to the 2002 period.

General and administrative expenses increased approximately $1.2 million between comparable periods, as a result of our continued growth, primarily from acquisitions, and increased expenses related to corporate governance activities. Additionally, the percentage of non-direct costs allocated to the pipeline operations segment has increased in the 2003 period as our pipeline operations have grown. Gross profit (excluding depreciation) includes a $0.6 million favorable impact resulting from the decrease in the average Canadian dollar to U.S. dollar exchange rate for the 2003 period as compared to the 2002 period. Gross profit (excluding depreciation) was approximately $24.2 million in the second quarter of 2003, an increase of 56% as compared to the $15.5 million reported for the quarter ended June 30, 2002.

Gathering, Marketing, Terminalling and Storage Operations

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and liquefied petroleum gas ("LPG") plus the sale of additional barrels exchanged through buy/sell arrangements entered into to enhance the margins of the gathered and bulk-purchased volumes. Gross margin from our gathering and marketing activities is dependent on our ability to sell crude oil and LPG at a price in excess of our aggregate cost. These operations are margin businesses and are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and LPG and fluctuations in market-related indices. Accordingly, an increase or decrease in revenues is not necessarily an indication of segment performance.

We own and operate approximately 24.2 million barrels of above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Approximately 11.0 million barrels of our 24.2 million barrels of tankage is used primarily in our Gathering, Marketing, Terminalling and Storage Operations and the balance is used in our Pipeline Operations segment. On a stand alone basis, gross margin from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities.

Crude oil prices have historically been very volatile and cyclical. Over the last 13 years, the NYMEX benchmark price has ranged from as high as $40.00 per barrel to as low as $10.00 per barrel. Our business strategy recognizes this volatility and the inherent inefficiencies such conditions create. Accordingly, we have deliberately configured our assets and integrated our activities in this segment in an effort to provide a counter-cyclical balance between our gathering and marketing activities and our terminalling and storage activities, and execute different hedging strategies to stabilize and enhance margins and reduce the negative impact of crude oil market volatility.

During the second quarter of 2003 we continued to experience the relatively high level of volatility and strong backwardation in the crude oil markets that was present in the first quarter. The NYMEX benchmark price of crude oil ranged from as high as $32.50 per barrel to as low as $25.04 per barrel during this quarter. Although this type of market does not provide economics for storing crude oil in our tanks, in conjunction with our hedging strategies, it does enhance the returns of our gathering and marketing activities. In contrast, during much of the second quarter of 2002, the crude oil market was in contango, which enhances the economics of storing crude oil and increases demand for storage services from third parties, but is generally disadvantageous for our gathering and marketing activities.

As a result of completing our Phase II and Phase III expansions at our Cushing facility and the consummation of several acquisitions, total tankage dedicated to our Gathering, Marketing, Terminalling and Storage Operations was approximately 5.0 million barrels greater in the second quarter of 2003 relative to the second quarter of 2002. A portion of such tankage was employed in hedging activities related to our gathering and marketing activities in the second quarter of 2003.

The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	Three months ended June 30, 2003	Three months ended June 30, 2002
Operating Results (in millions) (1)		
Revenues	$ 2,566.2	$ 1,873.9
Cost of sales and operations (excluding depreciation)	2,539.6	1,851.0
Gross Margin (excluding depreciation)	26.6	22.9
General and administrative expenses (2)	7.7	7.8
Gross Profit (excluding depreciation)	$ 18.9	$ 15.1
Noncash SFAS 133 impact (3)	$ 0.2	$ 1.1
Maintenance capital	$ 0.2	$ 0.1
Average Daily Volumes (thousands of barrels per day) (4)		
Crude oil lease gathering	425	410
Crude oil bulk purchases	88	65
Total	513	475
LPG sales	24	31
Cushing Terminal throughput	199	78
Cushing Terminal storage leased to third parties, monthly average volumes	1,120	1,400

(1) Revenues and cost of sales and operations include intersegment amounts.
(2) General and administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for the second quarter of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Amounts related to SFAS 133 are included in revenues, gross margin (excluding depreciation) and gross profit (excluding depreciation).
(4) Volumes associated with acquisitions represent weighted averaged daily amounts for the number of days we actually owned the assets over the total days in the period.

Because of the overall counter-cyclical balance of our assets and the flexibility embedded in our business strategy, the benefit we received from the pronounced backwardation, volatile market conditions and increased tankage available to our gathering and marketing business in the second quarter of 2003 more than offset the adverse impact of reduced storage activities. During much of the second quarter of 2002, the crude oil market was in contango. In addition, the Canadian dollar to U.S. dollar exchange rate decreased to an average rate of 1.40 for the three months ended June 30, 2003, from an average rate of 1.55 for the three months ended June 30, 2002, which resulted in a favorable impact on the results reported for our Canadian operations.

As a result of these factors, our gross margin (excluding depreciation) increased approximately $3.7 million or 16% to $26.6 million as compared to $22.9 million in the second quarter of 2002. The increase in gross margin in the current year period includes the approximately $0.8 million favorable impact from the decrease in the Canadian dollar to U.S. dollar exchange rate in the 2003 period as compared to the 2002 period. Gross margin increased for the current period despite an increase in operating expense of $4.5 million and a $0.9 million reduction in the amount of non-cash, mark-to-market gains reported pursuant to SFAS 133. The increase in operating expenses to $18.3 million in the 2003 period from $13.8 million in the 2002 period related primarily to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher fuel costs. The second quarter 2003 SFAS 133 non-cash mark-to-market gain was $0.2 million compared to a gain of $1.1 million in the prior year quarter.

General and administrative expenses were relatively flat as the percentage of non-direct costs allocated to the Gathering, Marketing, Terminalling and Storage Operations segment decreased. Gross profit (excluding depreciation) was approximately $18.9 million in the second quarter of 2003, compared to $15.1 million reported for the quarter ended June 30, 2002. The increase includes the approximately $0.5 million favorable impact from the decrease in the Canadian dollar to U.S. dollar exchange rate that was more than offset by a $0.9 million reduction in the amount of non-cash, mark-to-market gains reported pursuant to SFAS 133.

As discussed previously, the majority of instruments we are required to mark-to-market at the end of each quarterly period pursuant to SFAS 133 do serve as economic hedges that offset future physical positions not reflected in current results. Therefore, we believe mark-to-market adjustments to net income required under SFAS 133 do not provide a complete depiction of the economic substance of the transaction, as it only represents the derivative side of these transactions and does not take into account the offsetting physical position. In addition, the impact will vary from quarter to quarter based on market prices at the end of the quarter, which are impossible for us to control or forecast, and the SFAS 133 adjustments will reverse in future periods. Accordingly, when we internally evaluate our results for performance against expectations, public guidance and trend analysis, we exclude the non-cash, mark-to-market impact of SFAS 133. Thus, we present the impact of the SFAS 133 adjustments because we believe such amounts affect the comparison of the fundamental operating results for the periods presented.

In addition to market conditions and our hedging activities, the primary drivers of the performance of our gathering, marketing, terminalling and storage operations segment are crude oil lease gathered volumes and LPG sales volumes. Crude oil bulk purchase volumes are not considered a driver as they are primarily used to enhance margins of lease gathered barrels. Gross profit per barrel (excluding depreciation) for the quarters ended June 30, 2003 and 2002, was $0.46 per barrel and $0.38 per barrel, respectively.

For the quarter ended June 30, 2003, we gathered from producers, using our assets or third-party assets, approximately 425,000 barrels of crude oil per day, an increase of 4% over similar activities in the second quarter of 2002. In addition, we purchased in bulk, primarily at major trading locations, approximately 88,000 barrels of crude oil per day in the 2003 period and approximately 65,000 barrels per day in the 2002 period. Storage leased to third parties at our Cushing facility decreased to an average of 1.1 million barrels per month in the current year quarter from an average of 1.4 million barrels per month in the second quarter of 2002. Terminal throughput volumes averaged approximately 199,000 barrels per day and 78,000 barrels per day for the quarters ended June 30, 2003 and 2002, respectively. Also during the quarter, we marketed approximately 24,000 barrels per day of LPG, a decrease of approximately 23% over the approximately 31,000 barrels marketed in the second quarter of 2002.

Revenues from our gathering, marketing, terminalling and storage operations were approximately $2.6 billion and $1.9 billion for the quarters ended June 30, 2003 and 2002, respectively. Revenues and cost of sales and operations (excluding depreciation) for 2003 were impacted by higher average prices and crude oil lease gathering volumes in the 2003 period as compared to the 2002 period. The average NYMEX price for crude oil was $28.96 per barrel and $26.24 per barrel for the second quarter of 2003 and 2002, respectively.

Other Expenses

Depreciation and Amortization

Depreciation expense related to operations was approximately $9.7 million for the quarter ended June 30, 2003, compared to $6.1 million for the same period of 2002. Approximately $2.4 million of the increase is associated with the assets acquired in the Shell acquisition. The remainder of the increase is primarily related to the completion of various capital expansion projects and other smaller acquisitions. Depreciation and amortization expense related to general and administrative items increased approximately $0.6 million to $1.7 million in the second quarter of 2003 from the second quarter of 2002. The increase was because of higher debt issue costs related to the amendment of our credit facilities during 2002 and the sale of senior unsecured notes in September 2002 as well as a number of various other items. Debt amortization costs included in depreciation and amortization expense were $1.0 million and $0.8 million in the second quarter of 2003 and 2002, respectively.

Interest Expense

Interest expense increased approximately $2.1 million to $8.5 million for the quarter ended June 30, 2003, from $6.4 million for the comparable 2002 period. The increase was primarily related to an increase in the average debt balance during the 2003 period to approximately $515.0 million from approximately $410.0 million in the 2002 period, which resulted in additional interest expense of approximately $1.9 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. In addition, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $0.4 million of the increase in the 2003 period. These increases were partially offset by a decrease in interest expense of approximately $0.2 million because of a decline in the annualized weighted average interest rate to 6.1% in the 2003 period from 6.3% in the 2002 period.

Six Months Ended June 30, 2003 and 2002

For the six months ended June 30, 2003, we reported net income of $47.7 million on total revenues of $6.0 billion compared to net income for the same period in 2002 of $31.2 million on total revenues of $3.5 billion. Our net income includes a $1.1 million gain and a $1.7 million loss related to SFAS 133 for the six months ended June 30, 2003 and 2002, respectively.

The following table reflects our results of operations for each segment:

	Pipeline	Gathering, Marketing, Terminalling & Storage	Total
		(in millions)	
Six Months Ended June 30, 2003 [1]			
Revenues	$ 324.8	$ 5,689.3	$ 6,014.1
Cost of sales and operations (excluding depreciation)	271.3	5,629.9	5,901.2
Gross margin (excluding depreciation)	53.5	59.4	112.9
General and administrative expenses [2]	9.1	16.1	25.2
Gross profit (excluding depreciation)	$ 44.4	$ 43.3	$ 87.7
Noncash SFAS 133 impact [3]	$ —	$ 1.1	$ 1.1
Maintenance capital	$ 3.8	$ 0.4	$ 4.2
Six Months Ended June 30, 2002 [1]			
Revenues	$ 203.6	$ 3,333.9	$ 3,537.5
Cost of sales and operations (excluding depreciation)	166.3	3,291.1	3,457.4
Gross margin (excluding depreciation)	37.3	42.8	80.1
General and administrative expenses [2]	6.6	15.3	21.9
Gross profit (excluding depreciation)	$ 30.7	$ 27.5	$ 58.2
Noncash SFAS 133 impact [3]	$ —	$ (1.7)	$ (1.7)
Maintenance capital	$ 2.2	$ 0.6	$ 2.8

(1) Revenues and costs of sales and operations include intersegment amounts.
(2) General and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A by segment for the first half of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Amounts related to SFAS 133 are included in revenues, gross margin (excluding depreciation), and gross profit (excluding depreciation).

Pipeline Operations

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Six months ended June 30, 2003	Six months ended June 30, 2002
Operating Results (in millions) [1]		
Tariff activities revenues	$ 72.1	$ 40.6
Margin activities revenues	252.7	163.0
Total pipeline operations revenues	324.8	203.6
Cost of sales and operations (excluding depreciation)	271.3	166.3
Gross Margin (excluding depreciation)	53.5	37.3
General and administrative expenses [2]	9.1	6.6
Gross Profit (excluding depreciation)	$ 44.4	$ 30.7
Maintenance capital	$ 3.8	$ 2.2
Average Daily Volumes (thousands of barrels per day) [3]		
Tariff activities		
All American	61	64
Basin	245	n/a
Other domestic	261	153
Canada	181	178
Total tariff activities	748	395
Margin activities	81	72
Total	829	467

(1) Revenues and cost of sales and operations include intersegment amounts.
(2) General and administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for the first half of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

Total average daily volumes transported were approximately 829,000 barrels per day and 467,000 barrels per day for the six months ended June 30, 2003 and 2002, respectively. As discussed above, we have completed a number of acquisitions during 2003 and 2002 that have impacted the results of operations herein. The following table reflects our total average daily volumes from our tariff activities by year of acquisition for comparison purposes:

	Six months ended June 30, 2003	Six months ended June 30, 2002
	(thousands of barrels per day)	
Tariff activities [1] [2]		
2003 acquisitions	33	—
2002 acquisitions	334	12
All other pipeline systems	381	383
Total tariff activities average daily volumes	748	395

(1) The 2003 acquisitions include the Red River pipeline system, the Iatan gathering system, the Mesa pipeline system and the South Louisiana assets. The 2002 acquisitions include the pipeline systems included in the Shell acquisition and the Butte pipeline system.
(2) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

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Average daily volumes from our tariff activities were approximately 748,000 barrels per day compared to approximately 395,000 barrels per day for the prior year period. Approximately 355,000 barrels per day of the increase in the current year period is due to volumes transported on the pipelines acquired in 2003 and 2002, including approximately 319,000 on the assets acquired in the Shell acquisition. In addition, we transported approximately 3,000 barrels per day more on our Canadian pipelines in the first half of 2003 than in the first half of 2002. This increase in the first six months of 2003 over the same period in the prior year is due to the completion of capital expansion projects during 2002 that allowed for additional volumes on certain of our Canadian pipelines, partially offset by lower volumes in the second quarter due to refinery turnarounds that reduced throughput on our Milk River system. The increase in volumes from our Canadian pipelines was offset by decreases on various domestic pipeline systems including an approximate 3,000 barrel per day decrease in our All American tariff volumes attributable to OCS production.

Total revenues from our pipeline operations were approximately $324.8 million and $203.6 million for the six months ended June 30, 2003 and 2002, respectively. The increase in revenues was primarily related to our margin activities, which increased by approximately $89.7 million in the first half of 2003. This increase was primarily related to higher average prices on our margin activity on our San Joaquin Valley gathering system in the 2003 period as compared to the 2002 period, but was also positively impacted by higher volumes on our buy/sell arrangements in the current period. However, this business is a margin business and although revenues and cost of sales are impacted by the absolute level of crude oil prices, this factor has a limited impact on gross margin.

Revenues from our tariff activities increased approximately $31.5 million. The following table reflects our revenues from our tariff activities by year of acquisition for comparison purposes:

	Six months ended June 30,	
	2003	**2002**
	(in millions)	
Tariff activities revenues (1) (2)		
2003 acquisitions	$ 4.0	$ —
2002 acquisitions	25.9	0.3
All other pipeline systems	42.2	40.3
Total tariff activities	$72.1	$40.6

(1) Revenues include intersegment amounts.
(2) The 2003 acquisitions include the Red River pipeline system, the Iatan gathering system, the Mesa pipeline system and the South Louisiana assets. The 2002 acquisitions include the pipeline systems included in the Shell acquisition and the Butte pipeline system.

Total revenues from our tariff activities were approximately $72.1 million and $40.6 million for the six months ended June 30, 2003 and 2002, respectively. The increase in the first half of 2003 is predominately related to the inclusion of $29.9 million of revenues from the businesses acquired in 2003 and 2002, including approximately $25.8 million from the assets acquired in the Shell acquisition. Revenues from all other pipeline systems increased approximately $1.9 million to $42.2 million for the six months ended June 30, 2003, primarily because of our Canadian operations. Canadian revenues increased approximately $2.3 million primarily due to higher volumes and tariffs in the current period coupled with a $1.2 million favorable exchange rate impact. The favorable exchange rate impact resulted from a decrease in the Canadian to U.S. dollar exchange rate to an average rate of 1.45 for the six months ended June 30, 2003, from an average rate of 1.57 for the six months ended June 30, 2002. The increase in revenues from our Canadian operations was partially offset by decreased revenues from various of our U.S. pipeline systems, including our All American system on which we receive the highest per barrel tariffs among our pipeline operations.

As a result of these factors, pipeline operations gross margin (excluding depreciation) increased 43% to approximately $53.5 million for the six months ended June 30, 2003, from $37.3 million for the prior year period, an increase of approximately $16.2 million. Incorporated in this increase is approximately $0.8 million from a more favorable Canadian dollar to U.S. dollar exchange rate in the 2003 period as compared to the 2002 period. Such results also incorporate an increase in operating expenses to $27.7 million in the 2003 period from $13.1 million in the 2002 period related to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher utility costs.

General and administrative expenses increased approximately $2.5 million between comparable periods, as a result of our continued growth, primarily from acquisitions, and increased expenses related to corporate governance activities. Additionally, the percentage of non-direct costs allocated to the pipeline operations segment has increased in the 2003 period as our pipeline operations have grown. Gross profit (excluding depreciation) was approximately $44.4 million in the first half of 2003, an increase of 45% as compared to the $30.7 million reported for the six months ended June 30, 2002. Incorporated in this increase is approximately $0.8 million from a more favorable Canadian dollar to U.S. dollar exchange rate in the 2003 period as compared to the 2002 period.

Gathering, Marketing, Terminalling and Storage Operations

The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	Six months ended June 30,	
	2003	**2002**
Operating Results (in millions) [1]		
Revenues	$ 5,689.3	$ 3,333.9
Cost of sales and operations (excluding depreciation)	5,629.9	3,291.1
Gross Margin excluding depreciation	59.4	42.8
General and administrative expenses [2]	16.1	15.3
Gross Profit excluding depreciation	$ 43.3	$ 27.5
Noncash SFAS 133 impact [3]	$ 1.1	$ (1.7)
Maintenance capital	$ 0.4	$ 0.6
Average Daily Volumes (thousands of barrels per day) [4]		
Crude oil lease gathering	430	405
Crude oil bulk purchases	78	67
Total	508	472
LPG sales	45	45
Cushing Terminal throughput	187	71
Cushing Terminal storage leased to third parties, monthly average volumes	1,137	1,363

(1) Revenues and cost of sales and operations include intersegment amounts.
(2) General and administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for the first half of 2002 to conform to the refined presentation used beginning in the third quarter of 2002. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Amounts related to SFAS 133 are included in revenues, gross margin (excluding depreciation) and gross profit (excluding depreciation).
(4) Volumes associated with acquisitions represent weighted averaged daily amounts for the number of days we actually owned the assets over the total days in the period.

During the first half of the year, market conditions were extremely volatile as a confluence of several events caused the NYMEX benchmark price of crude oil to fluctuate widely, with periods of steep backwardation throughout the first half of 2003. The NYMEX benchmark price of crude oil ranged from as high as $39.99 per barrel to as low as $25.04 per barrel during this six month period. Results from the first quarter of 2003 were further enhanced by increased sales and higher margins in our LPG activities resulting from cold weather throughout the U.S. and Canada.

Because of the overall counter-cyclical balance of our assets and the flexibility embedded in our business strategy, the benefit we received from the pronounced backwardation, volatile market conditions and increased tankage available to our gathering and marketing business in the first half of 2003 more than offset the adverse impact of reduced storage activities. In contrast, during much of the first six months of 2002, the crude oil market was in contango.

As a result of these factors, our gross margin (excluding depreciation) increased approximately $16.6 million or 39% to $59.4 million as compared to $42.8 million in the first six months of 2002. These results incorporate an increase in operating expenses to $38.0 million in the 2003 period from $33.1 million in the 2002 period related to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher fuel costs. Also included is a favorable impact of $1.0 million resulting from a decrease in the average Canadian to U.S. dollar exchange rate to 1.45 in the 2003 period from 1.57 in the 2002 period. In addition, these results include a $1.1 million non-cash, mark-to-market gain pursuant to SFAS 133 in the first half of 2003 and a $1.7 million, SFAS 133 non-cash, mark-to-market loss in the comparable 2002 period. The impact of the SFAS 133 adjustments accounted for $2.8 million or approximately 17% of the increase in gross margin before depreciation.

General and administrative expenses increased by approximately $0.8 million between comparable periods as a result of our continued growth, primarily from acquisitions, and increased expenses primarily related to corporate governance activities. These increases were partially offset by a decrease in the percentage of non-direct costs allocated to the Gathering, Marketing, Terminalling and Storage Operations segment. Gross profit (excluding depreciation) was approximately $43.3 million in the first half of 2003, an increase of $15.8 million from the six months ended June 30, 2002. This increase incorporates the approximately $0.7 million favorable impact resulting from a decrease in the Canadian dollar to U.S. dollar exchange rate in the 2003 period as compared to the 2002 period. The impact of the SFAS 133 adjustments accounted for $2.8 million or approximately 18% of the increase in gross profit before depreciation.

In addition to market conditions and our hedging activities, the primary drivers of the performance of our Gathering, Marketing, Terminalling and Storage Operations segment are crude oil lease gathered volumes and LPG sales volumes. Crude oil bulk purchase volumes are not considered a driver as they are primarily used to enhance margins of lease gathered barrels. Gross profit per barrel (excluding depreciation) for the six months ended June 30, 2003 and 2002, was $0.50 per barrel and $0.34 per barrel, respectively.

For the six months ended June 30, 2003, we gathered from producers, using our assets or third-party assets, approximately 430,000 barrels of crude oil per day, an increase of 6% over similar activities in the first half of 2002. In addition, we purchased in bulk, primarily at major trading locations, approximately 78,000 barrels of crude oil per day in the 2003 period and approximately 67,000 barrels per day in the 2002 period. Storage leased to third parties at our Cushing facility decreased to an average of 1.1 million barrels per month in the first six months of 2003 from an average of 1.4 million barrels per month in the first half of 2002. Terminal throughput volumes averaged approximately 187,000 barrels per day and 71,000 barrels per day for the six months ended June 30, 2003 and 2002, respectively. Also during the first half of both 2003 and 2002, we marketed approximately 45,000 barrels per day of LPG.

Revenues from our Gathering, Marketing, Terminalling and Storage Operations were approximately $5.7 billion and $3.3 billion for the six months ended June 30, 2003 and 2002, respectively. Revenues and cost of sales and operations (excluding depreciation) for 2003 were primarily impacted by higher average prices and increased crude oil lease gathering volumes in the 2003 period as compared to the 2002 period. The average

NYMEX price for crude oil was $31.42 per barrel and $23.95 per barrel for the first half of 2003 and 2002, respectively.

Other Expenses

Depreciation and Amortization

Depreciation expense related to operations was approximately $19.0 million for the six months ended June 30, 2003, compared to $12.0 million for the same period of 2002. Approximately $4.8 million of the increase is associated with the assets acquired in the Shell acquisition. The remainder of the increase is primarily related to the completion of various capital expansion projects and other acquisitions. Depreciation and amortization expense related to general and administrative items increased approximately $1.0 million to $3.2 million in the first half of 2003 from the first half of 2002. The increase was because of higher debt issue costs related to the amendment of our credit facilities during 2002 and the sale of senior unsecured notes in September 2002 as well as a number of other smaller items. Debt amortization costs included in depreciation and amortization expense were $2.0 million and $1.5 million in the first six months of 2003 and 2002, respectively.

Interest Expense

Interest expense increased approximately $4.9 million to $17.7 million for the six months ended June 30, 2003, from $12.8 million for the comparable 2002 period. The increase was primarily related to an increase in the average debt balance during the 2003 period to approximately $520.0 million from approximately $390.0 million in the 2002 period, which resulted in additional interest expense of approximately $4.8 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. In addition, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $0.8 million of the increase in the 2003 period. These increases were partially offset by a decrease in interest expense of approximately $0.7 million because of a decline in the annualized weighted average interest rate to 6.1% in the 2003 period from 6.4% in the 2002 period.

Outlook

On July 29, 2003, we furnished information in a current report on Form 8-K containing management's guidance for operating and financial performance for the third and fourth quarters of 2003 and preliminary guidance for 2004, including a discussion of the significant factors and assumptions management considered in preparing our guidance, as well as a discussion of factors that could cause actual results to differ materially from results anticipated in the forward-looking statements. Information that is "furnished" in a Form 8-K is typically not included in a periodic report such as this quarterly report. As a result, the projections, assumptions and risk factors discussed in our 8-K furnished on July 29 are not incorporated by reference in this report.

This "Outlook" section and the section captioned "Forward Looking Statements and Associated Risks" identify certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Crude Oil Inventory. We value our crude oil inventory at the lower of cost or market, with cost determined using an average cost method. At June 30, 2003 we had approximately 320,000 barrels of inventory classified as unhedged operating inventory at a weighted average cost of $28.62 per barrel. The lower of cost or market method requires a write down of inventory to the market price at the end of a period in which our weighted average cost exceeds the market price. This method does not allow a write up of the inventory if the market price subsequently increases. As the weighted average cost of our unhedged operating inventory was below the June 30, 2003 market price for such crude oil, we did not have an adjustment in this period. Future fluctuations in crude oil prices could result in a period end lower of cost or market adjustment.

Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. Since 1998, we have completed numerous acquisitions for an aggregate purchase price of approximately $1.2 billion. We can give you no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us. In connection with these activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. At June 30, 2003, the amount of costs deferred pending final outcome was $0.2 million.

Vesting of Unit Grants under Long-Term Incentive Plan. Subject to additional vesting requirements, restricted units granted under our Long-Term Incentive Plan ("LTIP") may vest in the same proportion as the conversion of our outstanding subordinated units into common units. Certain of the grants contain additional vesting requirements related to the Partnership achieving targeted annualized distribution thresholds, generally $2.10, $2.30 and $2.50 per unit, in equal proportions. Most of the grants also require additional passage of time before vesting occurs. Under generally accepted accounting principles, we are required to recognize an expense when the financial tests for conversion of subordinated units and required distribution levels are met. Thus, for at least some of the grants, recognition of expense may occur in a period prior to actual vesting and issuance of units to satisfy the grants. The expense will be a non-cash charge to the extent units are issued to satisfy the grants.

At the current distribution level of $2.20 per unit, assuming the subordination conversion test is met, the costs associated with the vesting of up to approximately 825,000 units would be incurred or accrued in the fourth quarter of 2003 or the first half of 2004. At a distribution level of $2.30 to $2.49, the number of units would be approximately 913,000. At a distribution level at or above $2.50, the number of units would be approximately 1,000,000. Subject to providing employees holding a number of LTIP grants below a certain threshold the option to receive cash instead of units, which alternative is currently under consideration, we are currently planning to issue units to satisfy the first 975,000 restricted units vested and delivered (after any units withheld for taxes), and to purchase units in the open market to satisfy any vesting obligations in excess of that amount. Issuance of units would result in a non-cash compensation expense. Purchase of units would result in a cash charge to compensation expense. In addition, the "company match" portion of payroll taxes, plus the value of any units withheld for taxes, would result in a cash charge. The amount of the charge to expense will be determined by the unit price on the date vesting occurs multiplied by the number of units.

The timing of the vesting and the amount of the charge are subject to various factors, including the unit price on the date vesting occurs, and thus are not known at this time. At the current distribution level and based on an assumed market price of $30.00 per unit, the aggregate charge associated with this vesting, including the Partnership's employer-related taxes, is approximately $26 million. To the extent such obligations are satisfied through the issuance of new units, there would be a corresponding increase in partners' equity.

Contingent Equity Issuance. In connection with the CANPET acquisition in July 2001, approximately $26.5 million Canadian dollars of the purchase price, payable in common units, was deferred subject to various performance objectives being met. If these objectives are met as of December 31, 2003, the deferred amount is payable on April 30, 2004. The number of common units issued in satisfaction of the deferred payment will depend upon the average trading price of our common units for a ten day trading period prior to the payment date and the Canadian and U.S. dollar exchange rate on the payment date. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. At our option, the deferred payment may be paid in cash rather than the issuance of units. We believe that it is probable that the objectives will be met and the deferred amount will be paid in April 2004, however, it is not determinable beyond a reasonable doubt. Assuming the tests are met as of

December 31, 2003, and the entire obligation is satisfied with common units, based on the foreign exchange rate and unit price in effect at June 30, 2003, (1.35 Canadian to U.S. dollar exchange rate and $30.84 per unit price) approximately 650,000 units would be issued.

Pipeline Rate Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the Federal Energy Regulatory Commission ("FERC") under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines, which includes crude oil, as well as refined product and petrochemical pipelines, be just and reasonable and non-discriminatory. The Energy Policy Act of 1992 deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of the Energy Policy Act or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable under the Interstate Commerce Act. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate or that a provision of the tariff is unduly discriminatory or preferential. In a FERC proceeding involving SFPP, L.P., certain shippers are challenging grandfathered rates on the basis of changed circumstances since the passage of the Energy Policy Act. The ultimate disposition of this challenge may define "substantial change" in such a way as to make grandfathered rates more vulnerable to challenge than has historically been the case. We are uncertain what effect, if any, an unfavorable determination in the FERC proceeding might have on our grandfathered tariffs.

On June 26, 2003, the FERC issued a Notice of Proposed Rulemaking that, if adopted, would impose substantial new reporting burdens on oil pipeline companies. We are currently reviewing the impact the ruling would have on us if it is adopted.

On June 26, 2003, the Federal Energy Regulatory Commission FERC issued an interim rule that amends its Uniform Systems of Accounts for oil pipeline companies with respect to participation of a FERC-regulated subsidiary in the cash management arrangement of its non-FERC-regulated parent. We are currently assessing the impact of the rule, but we believe that although the rule may affect the way in which we manage cash, the incremental costs will not be significant.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At June 30, 2003, we had a working capital deficit of approximately $63.8 million, approximately $403.1 million (net of $10.0 million to refinance term loan maturities due in the next twelve months) of availability under our revolving credit facility and $151.5 million of availability under the letter of credit and hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

We funded the purchase of the acquisitions completed in the first six months of the year with funds drawn on our revolving credit facilities and available cash on hand. In March, we completed a public offering of 2,645,000 common units priced at $24.80 per unit. Net proceeds from the offering, including our general partner's proportionate capital contribution and expenses associated with the offering, were approximately $63.9 million and were used to pay down our revolving credit facilities.

We believe that we have sufficient liquid assets, cash from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely effect our cash flow. A material decrease in our cash flows would likely produce a corollary adverse effect on our borrowing capacity.

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Cash Flows

	Six Months Ended June 30,	
	2003	2002
	(in millions)	
Cash provided by (used in):		
Operating activities	$ 176.1	$117.9
Investing activities	(111.1)	(50.1)
Financing activities	(63.0)	(65.6)

Operating Activities. Net cash provided by operating activities for the six months ended June 30, 2003 was $176.1 million as compared to $117.9 million in the 2002 period. Cash provided by operating activities in the period consisted primarily of (i) net income of $47.7 million, (ii) depreciation and amortization of $22.2 million, (iii) a change in derivative fair value of $1.1 million and (iv) net changes in assets and liabilities of approximately $107.3 million. Cash provided by operating activities in the prior year period consisted primarily of (i) net income of $31.2 million, (ii) depreciation and amortization of $14.1 million, (iii) a change in derivative fair value related to SFAS 133 of $1.7 million and (iv) net changes in assets and liabilities of approximately $70.8 million. The net changes in assets and liabilities are generally the result of the timing of cash receipts related to sales and cash disbursements related to purchases, inventory and other expenses. Inventory purchases and sales are accounted for as a use and source, respectively, of cash provided by operating activities. Accordingly, during periods of significant inventory builds or draws, cash provided by operating activities will fluctuate significantly. Significant inventory activity is typically associated with periods when the market is transitioning into or out of contango, a market condition where prompt month crude oil prices trade at a discount to crude oil prices in one or more future months, and periods following acquisitions or expansion activities where the partnership builds working inventory to operate the expanded asset base. We had substantial inventory draws in both the 2003 and 2002 periods primarily attributable to the sale of inventory stored and hedged during a contango market.

Investing Activities. Net cash used in investing activities in 2003 includes approximately $79.6 million paid for acquisitions and approximately $37.5 million for additions to property and equipment. These additions consist of $16.0 million related to the construction of crude oil gathering and transmission lines in West Texas and $21.5 million related to the completion of the Cushing expansion and other capital projects. Net cash used in investing activities in 2002 includes a $15.7 million deposit related to our Shell acquisition, $7.1 million for the Butte acquisition and $5.4 million for the Cornerstone acquisition, and $20.8 million of capital expenditures primarily for the Cushing expansion and other capital projects.

Financing Activities. Cash provided by financing activities in 2003 consisted of (i) approximately $63.9 million of proceeds from the issuance of common units used to pay down outstanding balances on the revolving credit facility, (ii) $58.8 million of distributions paid to unitholders and the general partner, (iii) a $7.0 million repayment of a maturity under our senior secured term loan, (iv) net long-term borrowings under our revolving credit facilities of $29.1 million, and (v) net short-term debt repayments of $90.2 million primarily from the proceeds of inventory sales. Cash provided by financing activities in 2002 consisted primarily of (i) net long-term borrowings under our revolving credit facilities of $36.8 million used primarily to fund capital expenditures, (ii) net short-term debt repayments of $53.6 million primarily from the proceeds of inventory sales, and (iii) $47.0 million of distributions paid to unitholders and the general partner.

Universal Shelf

We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $700 million of debt or equity securities. At June 30, 2003, we have approximately $355 million remaining under this registration statement.

Contingencies

Litigation. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Indemnities. In November, 2002, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We are party to various contracts entered into in the ordinary course of business that contain indemnity provisions pursuant to which we indemnify the counterparties against various expenses. Our indemnity obligations are contingent upon the occurrence of events or circumstances specified in the contracts. No such events or circumstances have occurred at this time, and we do not consider our liability under such indemnity provisions, individually or in the aggregate, to be material to our financial position or results of operations.

Operational Hazards and Insurance. Pipelines, terminals or other facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since the Partnership and its predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we considered adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities including the potential loss of significant revenues. Over the last several years, our operations have expanded significantly, with total assets increasing approximately 180% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. Notwithstanding what we believe is a favorable claims history, the overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. This trend was reinforced in connection with the renewal of our insurance program in June 2003. Absent a material favorable change in available insurance markets, this trend of rising insurance-related costs is expected to continue as we continue to grow and expand. As a result, it is anticipated that we will elect to self insure more activities against certain of these operating hazards.

Environmental. In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. Our total environmental reserve, including the reserve associated with the assets that are subject to this agreement, approximated $6.0 million at June 30, 2003. We believe this environmental reserve is adequate. However, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

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Other. Since the terrorist attacks of September 11, 2001, the United States Government has issued numerous warnings that energy assets (including our nation's pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The Department of Transportation ("DOT") has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how the DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT "critical facilities" and therefore potential terrorist targets. In compliance with DOT guidance, we performed vulnerability analyses on our critical facilities and have instituted, or will institute as appropriate, any indicated security measures or procedures that are not already in place. The Transportation Safety Administration (an agency of the Department of Homeland Security, which is in the transitional phase of assuming responsibility from the DOT) may issue additional guidelines. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Industry Credit Markets and Accounts Receivable

Throughout the latter part of 2001 and all of 2002, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and extreme financial distress at several large, diversified energy companies, the energy industry has been especially impacted by these developments. Accordingly, we are exposed to an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions relate to our gathering and marketing activities that can generally be described as high volume and low margin activities. In our credit approval process, we make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit or advance cash payments. At June 30, 2003, we had received approximately $45.8 million of advance cash payments from third parties to mitigate credit risk. These proceeds reduced our working capital requirements and were used to reduce long-term borrowings.

Recent Accounting Pronouncements

We continuously monitor and revise our accounting policies as our business and relevant accounting literature change. At this time, there are several new accounting pronouncements that have recently been issued which will impact our accounting or disclosure, as they become effective. For further discussion of new accounting rules, see Item 1. Consolidated Financial Statements—Note 9 "Recent Accounting Pronouncements."

Forward-Looking Statements and Associated Risks

All statements, other than statements of historical fact, included in this report are forward-looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," and similar expressions and statements regarding our business strategy, plans and objectives for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on the All American Pipeline;
- declines in volumes shipped on the Basin Pipeline and our other pipelines by third party shippers;
- the availability of adequate supplies of and demand for crude oil in the areas in which we operate;
- the effects of competition;
- the success of our risk management activities;
- the impact of crude oil price fluctuations;
- the availability (or lack thereof) of acquisition or combination opportunities;
- successful integration and future performance of acquired assets;
- continued creditworthiness of, and performance by, our counterparties;
- successful third-party drilling efforts in areas in which we operate pipelines or gather crude oil;
- our levels of indebtedness and our ability to receive credit on satisfactory terms;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the impact of current and future laws and governmental regulations;
- the currency exchange rate of the Canadian dollar;
- environmental liabilities that are not covered by an indemnity or insurance;
- fluctuations in the debt and equity markets; and
- general economic, market or business conditions.

Other factors, such as the "Risk Factors Related to our Business" and the Recent Disruption in Industry Credit Markets discussed in Item 7 of our most recent annual report on Form 10-K or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risks included in Item 7A. in our 2002 Form 10-K. There have not been any material changes in that information other than those discussed below.

As of June 30, 2003 and December 31, 2002 the fair value of our crude oil futures contracts was approximately $12.0 million and $0.6 million respectively. A 10% price decrease would result in a decrease in fair value of $11.1 million and $4.3 million at June 30, 2003 and December 31, 2002, respectively.

During the first quarter of 2003, we converted a $50.0 million treasury lock into a 10-year LIBOR based swap that becomes effective in March 2004, contemporaneously with the expiration of an existing $50.0 million LIBOR based swap. At June 30, 2003, the fair value of our interest rate risk hedging instruments was a liability of approximately $13.3 million with $1.2 million maturing in 2004, $5.2 million in 2006 and $6.9 million in 2014.

As of June 30, 2003, the fair value of our currency exchange risk hedging instruments was a liability of approximately $4.3 million with $0.5 million maturing during 2003 and the remainder in 2006.

Item 4. CONTROLS AND PROCEDURES

We maintain written “disclosure controls and procedures,” which we refer to as our “DCP.” The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure. Our DCP is incremental to our system of internal accounting controls designed to comply with the requirements of Section 13(b)(2) of the Exchange Act.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP, as of June 30, 2003, under the supervision and with the participation of our management, including our Chief Executive Office and Chief Financial Officer. Management (including our Chief Executive Officer and Chief Financial Officer) has evaluated the effectiveness of the design and operation of our DCP as of June 30, 2003, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the second quarter and that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. § 1350 are furnished with this report as exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Item 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

None

Item 3. DEFAULTS UPON SENIOR SECURITIES

None

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

Item 5. OTHER INFORMATION

None

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Item 6. EXHIBITS AND REPORTS ON FORM 8-K

A. Exhibits

10.1	First Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan
31.1	Certification of Chief Executive Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
31.2	Certification of Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350

B. Reports on Form 8-K.

A current report on Form 8-K was furnished on August 5, 2003, in connection with disclosure of our presentation at the Enercom 8th Annual Oil & Gas Conference.

A current report on Form 8-K was furnished on July 29, 2003, in connection with disclosure of third quarter and full year 2003 projections and earnings guidance and preliminary guidance for certain aspects of financial performance for 2004.

A current report on Form 8-K was furnished on June 4, 2003, in connection with disclosure of our presentation at the Bear Stearns Global Credit Conference.

A current report on Form 8-K was furnished on April 25, 2003, in connection with disclosure of second quarter projections and earnings guidance.

A current report on Form 8-K was furnished on April 25, 2003, in connection with disclosure of our presentation to the Independent Petroleum Association of America’s Oil and Gas Investment Symposium.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned and thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P., its general partner

By: PLAINS ALL AMERICAN GP LLC,
its general partner

Date: August 11, 2003	By:	/s/ GREG L. ARMSTRONG
		Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)
Date: August 11, 2003	By:	/s/ PHIL KRAMER
		Phil Kramer, Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)

Exhibit 10.1

FIRST AMENDMENT TO
PLAINS ALL AMERICAN GP LLC 1998
LONG-TERM INCENTIVE PLAN
June 27, 2003

By resolution of the Compensation Committee of the Board of Directors of Plains All American GP LLC, the Plains All American GP LLC 1998 Long-Term Incentive Plan is hereby amended as follows:

1. The definition of “Award” in the Plan shall be amended in its entirety to read:

   “Award” means an Option or Restricted Unit (or cash equivalent) granted under the Plan.

2. Clause (v) of the penultimate sentence of Section 3 of the Plan is hereby amended in its entirety to read:

   (v) determine whether, how, to what extent, and under what circumstances Awards may be settled (including settlement in cash), exercised, canceled or forfeited;

3. Section 7(ii) of the Plan is hereby amended in its entirety to read:

Amendments to Awards. The Committee may waive any conditions or rights under, amend any terms of, or alter any Award theretofore granted (including without limitation requiring or allowing for an election to settle an award in cash), provided no change, other than pursuant to Section 7(iii), in any Award shall materially reduce the benefit to Participant without the consent of such Participant.

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

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

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

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

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

   (b) [intentionally omitted pursuant to SEC Release No. 34-47986];

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

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

Date: August 11, 2003

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phil Kramer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

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

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

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

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

   (b) [intentionally omitted pursuant to SEC Release No. 34-47986];

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

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

Date: August 11, 2003

/s/ PHIL KRAMER

Phil Kramer
Chief Financial Officer

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350**

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ending June 30, 2003 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

/s/ GREG L. ARMSTRONG

Name: Greg L. Armstrong
Date: August 11, 2003

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350

I, Phil Kramer, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ending June 30, 2003 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

/s/ PHIL KRAMER

Name: Phil Kramer
Date: August 11, 2003