UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2005

OR

o **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 x No o

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

At August 2, 2005, there were outstanding 67,914,576 Common Units.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	June 30, 2005	December 31, 2004
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 38,000	$ 12,988
Trade accounts receivable, net	1,035,774	521,785
Inventory	848,173	498,200
Other current assets	107,568	68,229
Total current assets	2,029,515	1,101,202
PROPERTY AND EQUIPMENT	2,012,677	1,911,509
Accumulated depreciation	(218,626)	(183,887)
	1,794,051	1,727,622
OTHER ASSETS		
Pipeline linefill in owned assets	165,957	168,352
Inventory in third party assets	61,351	59,279
Other, net	83,664	103,956
Total assets	$ 4,134,538	$ 3,160,411
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 1,141,364	$ 850,912
Due to related parties	40,917	32,897
Short-term debt	820,769	175,472
Other current liabilities	147,992	54,436
Total current liabilities	2,151,042	1,113,717
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	6,421	151,753
Senior notes, net of unamortized discount of $3,267 and $2,729, respectively	946,733	797,271
Other long-term liabilities and deferred credits	30,365	27,466
Total liabilities	3,134,561	2,090,207
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
PARTNERS' CAPITAL		
Common unitholders (67,914,976 and 62,740,218 units outstanding at June 30, 2005, and December 31, 2004, respectively)	970,199	919,826
Class B common unitholder (1,307,190 units outstanding at December 31, 2004)	—	18,775
Class C common unitholders (3,245,700 units outstanding at December 31, 2004)	—	100,423
General partner	29,778	31,180
Total partners' capital	999,977	1,070,204
	$ 4,134,538	$ 3,160,411

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, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(unaudited)		(unaudited)	
REVENUES				
Crude oil and LPG sales (includes buy/sell transactions of approximately $3,706,119 and $3,450,671 for the three month periods, and $7,125,168 and $5,285,528 for the six month periods, respectively)	$ 6,919,504	$ 4,931,969	$ 13,337,293	$ 8,555,451
Other gathering, marketing, terminalling and storage revenues	11,323	9,106	19,496	16,727
Pipeline margin activities revenues (includes buy/sell transactions of approximately $40,049 and $34,924 for the three month periods, and $73,557 and $81,347 for the six month periods, respectively)	174,858	138,831	332,485	281,166
Pipeline tariff activities revenues	55,022	51,829	109,929	83,035
Total revenues	7,160,707	5,131,735	13,799,203	8,936,379
COSTS AND EXPENSES				
Crude oil and LPG purchases and related costs (includes buy/sell transactions of approximately $3,583,578 and $3,374,566 for the three month periods, and $6,984,505 and $5,166,200 for the six month periods, respectively)	6,804,159	4,859,173	13,138,805	8,417,244
Pipeline margin activities purchases (includes buy/sell transactions of approximately $37,299 and $33,343 for the three month periods, and $68,798 and $77,686 for the six month periods, respectively)	167,531	132,694	319,045	269,128
Field operating costs (excluding LTIP charge)	66,846	59,035	130,322	95,851
LTIP charge—operations	975	—	1,319	567
General and administrative expenses (excluding LTIP charge)	19,198	19,603	39,414	35,081
LTIP charge—general and administrative	6,951	—	8,846	3,661
Depreciation and amortization	19,448	15,998	38,566	29,118
Total costs and expenses	7,085,108	5,086,503	13,676,317	8,850,650
Gain on sales of assets	445	84	445	84
OPERATING INCOME	76,044	45,316	123,331	85,813
OTHER INCOME/(EXPENSE)				
Interest expense (net of $346 and $219 capitalized for the three month periods, respectively, and $966 and $397 capitalized for the six month periods, respectively)	(14,253)	(9,967)	(28,811)	(19,499)
Interest and other income (expense), net	491	328	570	369
Income before cumulative effect of change in accounting principle	62,282	35,677	95,090	66,683
Cumulative effect of change in accounting principle	—	—	—	(3,130)
NET INCOME	$ 62,282	$ 35,677	$ 95,090	$ 63,553
NET INCOME—LIMITED PARTNERS	$ 57,602	$ 33,247	$ 86,867	$ 58,954
NET INCOME—GENERAL PARTNER	$ 4,680	$ 2,430	$ 8,223	$ 4,599
BASIC NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.76	$ 0.54	$ 1.27	$ 1.03
Cumulative effect of change in accounting principle	—	—	—	(0.05)
Net income	$ 0.76	$ 0.54	$ 1.27	$ 0.98
DILUTED NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.74	$ 0.54	$ 1.26	$ 1.03
Cumulative effect of change in accounting principle	—	—	—	(0.05)
Net income	$ 0.74	$ 0.54	$ 1.26	$ 0.98
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	67,893	61,556	67,706	59,985
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	69,274	61,556	68,719	59,985

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 95,090	$ 63,553
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	38,566	29,118
Cumulative effect of change in accounting principle	—	3,130
Change in derivative fair value	26,327	(556)
Long-Term Incentive Plan charge	10,165	4,228
Noncash amortization of terminated interest rate swap	790	714
Noncash loss on foreign currency revaluation	(918)	(573)
Net cash paid for terminated swaps	(865)	—
Gain on sales of assets	(445)	(84)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(589,411)	(27,918)
Inventory	(351,461)	(24,135)
Accounts payable and other current liabilities	311,073	99,423

Due to related parties	7,697	210
Net cash provided by (used in) operating activities	(453,392)	147,110
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(14,545)	(443,210)
Additions to property and equipment	(86,254)	(32,170)
Proceeds from sales of assets	3,380	737
Net cash used in investing activities	(97,419)	(474,643)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on long-term revolving credit facility	(143,639)	415,827
Net borrowings/(repayments) on working capital revolving credit facility	71,800	(12,100)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	575,300	(96,091)
Proceeds from the issuance of senior notes	149,277	—
Net proceeds from the issuance of common units	22,308	101,213
Distributions paid to unitholders and general partner	(92,657)	(72,673)
Other financing activities	(5,826)	(2,141)
Net cash provided by financing activities	576,563	334,035
Effect of translation adjustment on cash	(740)	1,417
Net increase in cash and cash equivalents	25,012	7,919
Cash and cash equivalents, beginning of period	12,988	4,137
Cash and cash equivalents, end of period	$ 38,000	$ 12,056
Cash paid for interest, net of amounts capitalized	$ 35,825	$ 20,547

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 Units		Class B Common Units		Class C Common Units		General Partner	Total	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
					(unaudited)				
Balance at December 31, 2004	62,740	$ 919,826	1,307	$ 18,775	3,246	$ 100,423	$ 31,180	67,293	$ 1,070,204
Private placement of common units	575	21,860	—	—	—	—	448	575	22,308
Conversion of Class B Units	1,307	18,323	(1,307)	(18,323)	—	—	—	—	—
Conversion of Class C Units	3,246	99,302	—	—	(3,246)	(99,302)	—	—	—
LTIP Issuance	47	1,863	—	—	—	—	38	47	1,901
Distributions	—	(81,694)	—	(801)	—	(1,988)	(8,174)	—	(92,657)
Net income	—	84,958	—	548	—	1,361	8,223	—	95,090
Other comprehensive income	—	(94,239)	—	(199)	—	(494)	(1,937)	—	(96,869)
Balance at June 30, 2005	**67,915**	**$ 970,199**	**—**	**$ —**	**—**	**$ —**	**$ 29,778**	**67,915**	**$ 999,977**

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

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,	
	2005	2004	2005	2004
	(unaudited)			
Net income	$ 62,282	$ 35,677	$ 95,090	$ 63,553
Other comprehensive income (loss)	(27,111)	14,047	(96,869)	3,233
Comprehensive income (loss)	$ 35,171	$ 49,724	$ (1,779)	$ 66,786

Statement of Changes in Accumulated Other Comprehensive Income

	Net Deferred Gain (Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2004	$ 25,937	$ 70,934	$ 96,871
Current period activity:			
Reclassification adjustments for settled contracts	(568)	—	(568)
Changes in fair value of outstanding hedge positions	(88,082)	—	(88,082)
Currency translation adjustment	—	(8,219)	(8,219)
Total period activity	(88,650)	(8,219)	(96,869)
Balance at June 30, 2005	$ (62,713)	$ 62,715	$ 2

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. ("PAA") is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquified petroleum gas and other natural gas related petroleum products collectively as "LPG." We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of June 30, 2005, and December 31, 2004, (ii) the results of our consolidated operations for the three months and six months ended June 30, 2005 and 2004, (iii) our consolidated cash flows for the six months ended June 30, 2005 and 2004, (iv) our consolidated changes in partners' capital for the six months ended June 30, 2005, (v) our consolidated comprehensive income for the three months and six months ended June 30, 2005 and 2004, and (vi) our changes in consolidated accumulated other comprehensive income for the six months ended June 30, 2005. 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 periods to conform to current period presentation. The results of operations for the six months ended June 30, 2005 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 2004 Annual Report on Form 10-K.

Note 2—Trade Accounts Receivable

The majority of our trade accounts receivable relate to our gathering and marketing activities and can generally be described as high volume and low margin activities. As is customary in the industry, a portion of these receivables is reflected net of payables to the same counterparty based on contractual agreements. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered, received 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. Based on these analyses, as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable. At June 30, 2005, substantially all of our net trade accounts receivable were less than 60 days past the scheduled invoice date. The following is a reconciliation of the changes in our allowance for doubtful trade accounts receivable balance (in millions):

Balance at December 31, 2004	$ 0.6
Applied to accounts receivable balances	(0.7)
Increase in reserve charged to expense	0.8
Balance at June 30, 2005	$ 0.7

We consider this reserve adequate; however, there is no assurance that actual amounts will not vary significantly from estimated amounts. The discovery of previously unknown facts or adverse developments affecting one of our counterparties or the industry as a whole could adversely impact our results of operations.

Note 3—Inventory and Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. Linefill and minimum working inventory requirements in owned assets are recorded at historical cost and consist of crude oil and LPG used to pack our pipelines such that when an incremental barrel enters, it forces a barrel out at another location, as well as the minimum amount of crude oil and LPG necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At June 30, 2005 and December 31, 2004, inventory and linefill consisted of:

	June 30, 2005			December 31, 2004		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory[1]						
Crude oil	14,959	$ 737.2	$ 49.28	8,716	$ 396.2	$ 45.46
LPG	3,132	108.5	$ 34.64	2,857	100.1	$ 35.04
Parts and supplies	N/A	2.5	N/A	N/A	1.9	N/A
Inventory subtotal	18,091	848.2		11,573	498.2	
Inventory in third-party assets						
Crude oil	1,248	50.5	$ 40.38	1,294	48.7	$ 37.64
LPG	318	10.9	$ 34.28	318	10.6	$ 33.33
Inventory in third-party assets subtotal	1,566	61.4		1,612	59.3	
Linefill						
Crude oil linefill	5,924	165.1	$ 27.87	6,015	168.4	$ 28.00
LPG linefill	26	0.9	$ 30.77	—	—	N/A
Linefill subtotal	5,950	166.0		6,015	168.4	
Total	25,607	$ 1,075.6		19,200	$ 725.9	

(1) Dollars per barrel reflect the impact of inventory hedges on a portion of our volumes.

Note 4—Debt

Debt consists of the following:

	June 30, 2005	December 31, 2004
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 4.0% and 3.0% at June 30, 2005 and December 31, 2004, respectively	$ 655.7	$ 80.4
Working capital borrowings, bearing interest at a rate of 4.2% and 3.7% at June 30, 2005 and December 31, 2004, respectively[1]	160.0	88.2
Other	5.1	6.9
Total short-term debt	820.8	175.5
Long-term debt:		
Senior notes—		
4.75% senior notes due August 2009, net of unamortized discount of $0.6 million and $0.7 million at June 30, 2005 and December 31, 2004, respectively	$ 174.4	$ 174.3
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.3 million at June 30, 2005 and December 31, 2004, respectively	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million and $0.6 million at June 30, 2005 and December 31, 2004, respectively	249.4	249.4
5.25% senior notes due June 2015, net of unamortized discount of $0.7 million at June 30, 2005	149.3	—
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million and $1.1 million at June 30, 2005 and December 31, 2004, respectively	173.9	173.9
Senior notes, net of unamortized discount	946.7	797.3
Long-term debt under credit facilities and other—		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004[1]	—	143.6
Other	6.5	8.1
Long-term debt under credit facilities and other	6.5	151.7
Total long-term debt[1][2]	953.2	949.0
Total debt	$ 1,774.0	$ 1,124.5

(1) At June 30, 2005 and December 31, 2004, we have classified $160.0 million and $88.2 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange ("NYMEX") margin deposits.

(2) At June 30, 2005, the aggregate fair value of our fixed rate senior notes is estimated to be approximately $1.0 billion.

During May 2005, we completed the sale of $150 million of 5.25% Senior Notes due 2015. The notes were sold at 99.518% of face value. The notes were co-issued by us and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations). Interest payments are due on June 15 and December 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

In May 2005, we amended our senior unsecured credit facility to increase the capacity from $750 million to $900 million and increased the sub-facility for Canadian borrowings to $360 million. The amended facility can be expanded to $1.25 billion, subject to obtaining additional lender commitments. Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million.

Note 5—Earnings Per Limited Partner Unit

Except as discussed in the following paragraph, basic and diluted net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership.

Emerging Issues Task Force Issue No. 03-06 (“EITF 03-06”), “Participating Securities and the Two-Class Method under FASB Statement No. 128” addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results, however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation.

The following sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at June 30, 2005 and 2004.

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(in thousands, except per unit data)			
Net income	$ 62,282	$ 35,677	$ 95,090	$ 63,553
Less:				
General partner’s incentive distribution paid	(3,504)	(1,752)	(6,450)	(3,396)
Subtotal	58,778	33,925	88,640	60,157
General partner 2% ownership	(1,176)	(678)	(1,773)	(1,203)
Net income available to limited partners	57,602	33,247	86,867	58,954
Pro forma additional general partner’s incentive distribution	(6,174)	—	(560)	—
Net income available to limited partners under EITF 03-06 (numerator for basic and diluted earnings per limited partner unit)	$ 51,428	$ 33,247	$ 86,307	$ 58,954
Denominator:				
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	67,893	61,556	67,706	59,985
Effect of dilutive securities:				
Weighted average LTIP units (see Note 7)	1,381	—	1,013	—
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	69,274	61,556	68,719	59,985
Basic net income per limited partner unit	$ 0.76	$ 0.54	$ 1.27	$ 0.98
Diluted net income per limited partner unit	$ 0.74	$ 0.54	$ 1.26	$ 0.98

Note 6—Partners’ Capital and Distributions

Private Placement of Common Units.

On February 25, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner’s proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. Although the net proceeds were used to repay indebtedness under our revolving credit facilities at closing, they will ultimately be used to fund a portion of our 2005 expansion capital program as those expenditures are incurred.

Conversion of Class B and Class C Common Units.

In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Distributions

The following table details the distributions we have declared and paid in 2005:

Distribution Payment Date	Distribution per Limited Partner Unit	Total of distribution paid to: Limited Partners	General partner: Incentive Distribution	General partner: 2% ownership
		(in millions, except per unit data)		
August 12, 2005[1]	$ 0.6500	$ 44.1	$ 3.8	$ 0.9
May 13, 2005	$ 0.6375	$ 43.3	$ 3.5	$ 0.9
February 14, 2005	$ 0.6125	$ 41.2	$ 3.0	$ 0.8

(1) The distribution we declared on July 22, 2005, is payable on August 12, 2005, to unitholders of record on August 2, 2005.

Note 7—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") and the 2005 Long-Term Incentive Plan (the "2005 LTIP") for employees and directors of our general partner and its affiliates who perform services for us.

Approximately 92,000 phantom units outstanding under the 1998 LTIP vested in May 2005. We paid cash in lieu of delivery of common units for approximately 20,000 of the phantom units and issued approximately 47,000 new common units (after netting for taxes) in connection with the vesting. As of June 30, 2005, there are approximately 57,000 phantom units outstanding under the 1998 LTIP, which have vesting terms over the next four years, if certain performance criteria are met. The majority of the awards outstanding under the 1998 LTIP have performance-based vesting terms and, therefore, we recognize expense when it is considered probable that the performance criteria will be met.

Four of our non-employee directors each have received an LTIP award of 5,000 units. These awards vest yearly in 25% increments (1,250 units each). The awards have an automatic re-grant feature such that as they vest, a similar amount is granted. For the other two non-employee directors, any director compensation is assigned to the entity that designated them as directors. In those cases, no LTIP award was granted, but a cash payment is made. In June 2005, 5,000 director units vested.

In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1.9 million phantom units and 1.4 million distribution equivalent rights ("DERs") under the 2005 LTIP. Approximately 1.4 million of the phantom units vest over a six year period (with performance accelerators) while the remaining awards vest over time only if certain performance criteria are met and are forfeited after seven years if the performance criteria are not met. No phantom units vest prior to the dates indicated below for each tranche. The DERs vest over time and terminate with the vesting or forfeiture of the related phantom units. The following awards were outstanding under the 2005 LTIP at June 30, 2005:

Annualized Distribution Rate	Date	Phantom Units A[1]	Phantom Units B[2]	Phantom Units Total	DERs A[1]	DERs B[2]	DERs Total
				(in thousands)			
$2.60	May 2007	561	150	711	363	150	513
$2.70	May 2008	—	—	—	136	75	211
$2.80	May 2009	421	150	571	136	75	211
$2.90	May 2010	—	—	—	136	100	211
$3.00	May 2010	421	200	622	136	100	211
		1,403	500	1,903	907	500	1,407

(1) Awards that vest over six years. Achievement of the indicated distribution rate performance criteria can accelerate the vesting to the date indicated. The phantom unit awards are common stock equivalents as they will vest at the end of a determinant time and are included in our diluted earnings per unit calculation.

(2) Awards that vest only upon the achievement of the distribution rate performance criteria and the date indicated. In addition, the awards will be forfeited if the performance criteria are not met in seven years. These awards are not common stock equivalents as they may never vest and are not included in our diluted earnings per unit calculation.

Compensation expense is recognized ratably over time for the phantom units and DERs that vest based on the passage of time. To the extent that the vesting of the awards or DERs is accelerated, the related compensation expense will also be accelerated. For those phantom units and DERs that vest upon the achievement of performance criteria, expense is recognized when it is considered probable the criteria will be achieved.

We have concluded that it is probable that we will achieve a $2.80 annualized distribution rate and therefore have accelerated the vesting of the portion of the awards that vest up to that rate. We recognized total compensation expense of approximately $7.9 million in the second quarter of 2005 for a total of $10.2 million in the first half of 2005 related to the awards granted under our 1998 LTIP and our 2005 LTIP.

Note 8—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, as well as 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 the hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, as well as with respect to expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies.

The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to Accumulated Other Comprehensive Income ("OCI") and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective (as defined in Statement of Financial Accounting Standard No. 133) in offsetting changes in cash flows of the hedged items are marked-to-market in revenues each period.

During the first half of 2005, our earnings include a net gain of approximately $77.8 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) a net mark-to-market loss of $26.3 million (a $13.4 million loss in the first quarter and a $12.9 million loss in the second quarter), which is comprised of:

- the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a loss of approximately $25.9 million) and

- the net change in fair value during the quarter of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a loss of approximately $0.4 million).

b) a net gain of $104.1 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during the first half of 2005.

The following table summarizes the net assets and liabilities related to the fair value of our open derivative positions on our consolidated balance sheet as of June 30, 2005:

Other current assets	$ 25.5
Other long-term assets	0.9
Other current-liabilities	(100.4)
Other long-term liabilities and deferred credits	(6.5)

The net liability as of June 30, 2005, relates mostly to unrealized losses on effective cash flow hedges that are deferred to OCI. At June 30, 2005, there is a total unrealized net loss of approximately $62.7 million deferred to OCI. This includes $56.5 million, which predominantly relates to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and $6.2 million relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an increase in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. 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.

Of the total net loss deferred in OCI at June 30, 2005, a net loss of $57.8 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is 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.

During the six months ended June 30, 2005, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 9—Commitments and Contingencies

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of our personnel, the U.S. Environmental Protection Agency

("EPA"), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.5 million to $4.0 million. We continue to work with the appropriate state and federal environmental authorities with respect to site restoration and no enforcement proceedings have been instituted by any governmental authority at this time.

General. 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.

Environmental

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. As we expand our pipeline assets through acquisitions, we expect the absolute number of releases during a given period to increase and we have, in fact, experienced such an increase in connection with our purchase of the Link assets. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such leaks (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. We cannot predict the effect, if any, of increased scrutiny by governmental authorities of the crude oil pipeline business.

At June 30, 2005, our reserve for environmental liabilities totaled approximately $23.7 million. Approximately $14.9 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, 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.

Other

A pipeline, terminal or other facility 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. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts we consider reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Additionally, we choose to self-insure certain types of risks, including risks associated with gradual seepage and pollution and property damage for pipe in the ground, which we believe are cost prohibitive to insure.

The occurrence of a significant event not fully insured, indemnified or reserved 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 10—Operating Segments

Our operations consist of two operating segments: (i) pipeline transportation operations ("Pipeline") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the value of our principal fixed assets. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining "available cash", consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. 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. The following table reflects certain financial data for each segment for the periods indicated:

	Pipeline	GMT&S	Total
Three Months Ended June 30, 2005[(1)]		(in millions)	
Revenues:			
External Customers (includes buy/sell revenues of $40.0 and $3,706.1, respectively)[(2)]	$ 229.9	$ 6,930.8	$ 7,160.7

	Pipeline	GMT&S	Total
Intersegment(3)	30.6	0.2	30.8
Total revenues of reportable segments	$ 260.5	$ 6,931.0	$ 7,191.5
Segment profit(2)(4)(5)	$ 41.4	$ 53.7	$ 95.1
Non-cash SFAS 133 impact(2)	$ —	$ (12.9)	$ (12.9)
Maintenance capital	$ 2.5	$ 1.5	$ 4.0

	Pipeline	GMT&S (in millions)	Total
Three Months Ended June 30, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $34.9 and $3,450.7, respectively)(2)	$ 190.7	$ 4,941.1	$ 5,131.8
Intersegment(3)	32.1	0.2	32.3
Total revenues of reportable segments	$ 222.8	$ 4,941.3	$ 5,164.1
Segment profit(2)(4)(5)	$ 47.7	$ 13.5	$ 61.2
Non-cash SFAS 133 impact(2)	$ —	$ (6.9)	$ (6.9)
Maintenance capital	$ 0.6	$ 0.7	$ 1.3
Six Months Ended June 30, 2005(1)			
Revenues:			
External Customers (includes buy/sell revenues of $73.6 and $7,125.2, respectively)(2)	$ 442.4	$ 13,356.8	$ 13,799.2
Intersegment(3)	65.3	0.4	65.7
Total revenues of reportable segments	$ 507.7	$ 13,357.2	$ 13,864.9
Segment profit(2)(4)(5)	$ 91.5	$ 70.0	$ 161.5
Non-cash SFAS 133 impact(2)	$ —	$ (26.3)	$ (26.3)
Maintenance capital	$ 5.3	$ 2.7	$ 8.0
Six Months Ended June 30, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $81.3 and $5,285.5, respectively)(2)	$ 364.2	$ 8,572.2	$ 8,936.4
Intersegment(3)	47.9	0.4	48.3
Total revenues of reportable segments	$ 412.1	$ 8,572.6	$ 8,984.7
Segment profit(2)(4)(5)	$ 73.2	$ 41.6	$ 114.8
Non-cash SFAS 133 impact(2)	$ —	$ 0.5	$ 0.5
Maintenance capital	$ 2.1	$ 1.0	$ 3.1

(1) In May 2005, we reclassified certain minor pipeline gathering assets from the GMT&S segment to the Pipeline segment. Historically, we have been the sole shipper on these assets as part of our gathering and marketing operations. Prior period segment information has not been restated for this change since the impact to such periods was not material.

(2) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(3) Intersegment sales are conducted at arms length.

(4) GMT&S segment profit includes interest expense of $5.8 million and $0.3 million for the quarters ended June 30, 2005 and 2004, respectively, and $9.2 million and $0.4 million for the six month periods ended June 30, 2005 and 2004, respectively, on contango inventory purchases.

(5) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle:

	For the three months ended June 30, 2005	For the three months ended June 30, 2004	For the six months ended June 30, 2005	For the six months ended June 30, 2004
	(in millions)			
Segment profit	$ 95.1	$ 61.2	$ 161.5	$ 114.8
Depreciation and amortization	(19.4)	(16.0)	(38.6)	(29.1)
Gain on sales of assets	0.4	0.1	0.4	0.1
Interest expense	(14.3)	(10.0)	(28.8)	(19.5)
Interest income and other, net	0.5	0.4	0.6	0.4
Income before cumulative effect of change in accounting principle	$ 62.3	$ 35.7	$ 95.1	$ 66.7

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes. For more detailed information regarding the basis of presentation for the following financial information, see the "Notes to the Consolidated Financial Statements." Our discussion and analysis includes the following:

- Executive Summary
- Acquisition Activities

- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Commitments
- Forward-Looking Statements and Associated Risks

Executive Summary

Company Overview

We are engaged in interstate and intrastate crude oil transportation and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquified petroleum gas and other natural gas related petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada. We were formed in September of 1998, and our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P.

We are one of the largest midstream crude oil companies in North America. As of June 30, 2005, we owned approximately 15,000 miles of active crude oil pipelines, approximately 37 million barrels of active terminalling and storage capacity and over 400 transport trucks. Currently, we handle an average of over 3.0 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada.

Our operations consist of two operating segments: (i) pipeline transportation operations ("Pipeline") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets.

2005 Operating Results Overview

During the second quarter of 2005, we recognized net income of $62.3 million and earnings per diluted limited partner unit of $0.74, compared to $35.7 million and $0.54, respectively during the second quarter of 2004.

Key items in the second quarter of 2005 included:

- Very favorable market conditions characterized by relatively strong contango market conditions and reasonably high volatility of crude oil.
- The inclusion in the second quarter of 2005 of an aggregate charge of approximately $7.9 million related to both our 1998 Long-Term Incentive Plan ("1998 LTIP") and our 2005 Long-Term Incentive Plan ("2005 LTIP").
- A non-cash loss of approximately $12.9 million in the second quarter of 2005 resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").

During the first half of 2005, we recognized net income of $95.1 million and earnings per diluted limited partner unit of $1.26, compared to $63.6 million and $0.98, respectively during the first half of 2004. The first half of 2005 was characterized by similar market conditions as were found in the second quarter. Other items impacting first half results were (i) the contributions from assets acquired during 2004, (ii) an aggregate charge of $10.2 million related to our 1998 and 2005 LTIP, and (iii) a non-cash loss of approximately $26.3 million resulting from the mark-to-market of open derivative positions pursuant to SFAS 133. Earnings per limited partner unit (both basic and diluted) for the 2005 periods were reduced by the application of Emerging Issues Task Force Issue No. 03-06 "Participating Securities and the Two-Class Method under FASB Statement No. 128." See Note 5 "Earnings Per Limited Partner Unit" in "Notes to the Consolidated Financial Statements."

Acquisition Activities

We completed several acquisitions during 2005 and 2004 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase prices were allocated, in accordance with SFAS 141 "Business Combinations." Our ongoing acquisition activity is discussed further in "Outlook" below.

During the first half of 2005, we completed three small transactions for aggregate consideration of approximately $24.3 million. The transactions included several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. These acquisitions did not materially impact our results of operations, either individually or in the aggregate.

During 2004, we completed several acquisitions for aggregate consideration of approximately $549.5 million. The aggregate consideration includes cash paid, transaction costs and assumed liabilities and net working capital items. The Link and Capline acquisitions had a material impact on our operations. The following table summarizes our 2004 acquisitions:

Acquisition	Effective Date	Acquisition Price	Operating Segment
		(in millions)	
Capline and Capwood Pipeline Systems ("Capline acquisition")	03/01/04	$ 158.5	Pipeline
Link Energy LLC ("Link acquisition")	04/01/04	332.3	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04	32.0	GMT&S
Other	various	7.7	GMT&S
Total 2004 Acquisitions		$ 549.5	

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline and (ii) GMT&S. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain, and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the value of our principal fixed assets. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining "available cash", consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. 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. See Note 10 "Operating Segments" in the "Notes to the Consolidated Financial Statements"

for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle. The following table reflects our results of operations and maintenance capital for each segment.

	Pipeline	GMT&S
	(in millions)	
Three Months Ended June 30, 2005(1)(2)		
Revenues	$ 260.5	$ 6,931.0
Purchases(3)	(167.8)	(6,834.7)
Field operating costs (excluding LTIP charge)	(37.7)	(29.1)
LTIP charge—operations	(0.3)	(0.7)
Segment G&A expenses (excluding LTIP charge)(4)	(9.2)	(9.9)
LTIP charge—general and administrative(4)	(4.1)	(2.9)
Segment profit	$ 41.4	$ 53.7
Noncash SFAS 133 impact(5)	$ —	$ (12.9)
Maintenance capital	$ 2.5	$ 1.5
Three Months Ended June 30, 2004 (2)		
Revenues	$ 222.8	$ 4,941.3
Purchases(3)	(132.9)	(4,891.3)
Field operating costs	(31.9)	(27.2)
Segment G&A expenses(4)	(10.3)	(9.3)
Segment profit	$ 47.7	$ 13.5
Noncash SFAS 133 impact(5)	$ —	$ (6.9)
Maintenance capital	$ 0.6	$ 0.7

Table continued on following page

	Pipeline	GMT&S
	(in millions)	
Six Months Ended June 30, 2005(1)(2)		
Revenues	$ 507.7	$ 13,357.2

Purchases[3]	(319.5)	(13,204.1)
Field operating costs (excluding LTIP charge)	(71.7)	(58.6)
LTIP charge—operations	(0.4)	(0.9)
Segment G&A expenses (excluding LTIP charge)[4]	(19.4)	(20.0)
LTIP charge—general and administrative[4]	(5.2)	(3.6)
Segment profit	$ 91.5	$ 70.0
Noncash SFAS 133 impact[5]	$ —	$ (26.3)
Maintenance capital	$ 5.3	$ 2.7
Six Months Ended June 30, 2004[2]		
Revenues	$ 412.1	$ 8,572.6
Purchases[3]	(269.6)	(8,464.2)
Field operating costs (excluding LTIP charge)	(51.2)	(45.7)
LTIP charge—operations	(0.1)	(0.4)
Segment G&A expenses (excluding LTIP charge)[4]	(16.3)	(18.7)
LTIP charge—general and administrative[4]	(1.7)	(2.0)
Segment profit	$ 73.2	$ 41.6
Noncash SFAS 133 impact[5]	$ —	$ 0.5
Maintenance capital	$ 2.1	$ 1.0

(1) In May 2005, we reclassified certain minor pipeline gathering assets from the GMT&S segment to the Pipeline segment. Historically, we have been the sole shipper on these assets as part of our gathering and marketing operations. Prior period segment information has not been restated for this change since the impact to such periods was not material.

(2) Revenues and purchases include intersegment amounts.

(3) GMT&S purchases include interest of $5.8 million and $0.3 million for the quarters ended June 30, 2005 and 2004, respectively, and $9.2 million and $0.4 million for the six month periods ended June 30, 2005 and 2004, respectively, on contango inventory purchases.

(4) Segment 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. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.

(5) Amounts related to SFAS 133 are included in revenues and impact segment profit.

Pipeline Operations

As of June 30, 2005, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active 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 (collectively referred to as “tariff activities”), as well as barrel exchanges and buy/sell arrangements (collectively referred to as “pipeline margin activities”). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit 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 field costs of operating the pipeline. Segment profit 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 segment for the periods indicated:

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(in millions)			
Operating Results[1]				
Revenues				
Tariff activities	$ 85.6	$ 84.0	$ 175.3	$ 130.9
Pipeline margin activities[2]	174.9	138.8	332.4	281.2
Total pipeline operations revenues	260.5	222.8	507.7	412.1
Costs and Expenses				
Pipeline margin activities purchases	(167.8)	(132.9)	(319.5)	(269.6)
Field operating costs (excluding LTIP charge)	(37.7)	(31.9)	(71.7)	(51.2)
LTIP charge—operations	(0.3)	—	(0.4)	(0.1)
Segment G&A expenses (excluding LTIP charge)[3]	(9.2)	(10.3)	(19.4)	(16.3)
LTIP charge—general and administrative[3]	(4.1)	—	(5.2)	(1.7)
Segment profit	$ 41.4	$ 47.7	$ 91.5	$ 73.2
Maintenance capital	$ 2.5	$ 0.6	$ 5.3	$ 2.1
Average Daily Volumes (thousands of barrels per day)[4]				
Tariff activities				
All American	50	59	52	57
Basin	283	271	280	273
Capline	143	169	152	112
West Texas/New Mexico Area Systems[5]	410	374	406	291
Canada	248	259	258	250
Other	603	463	548	302
Total tariff activities	1,737	1,595	1,696	1,285
Pipeline margin activities	67	74	71	73

Total	1,804	1,669	1,767	1,358

(1) Revenues and purchases include intersegment amounts.

(2) The three month periods include revenues associated with buy/sell arrangements of $40.0 million and $34.9 million for the quarters ended June 30, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 12,800 barrels per day and 11,900 barrels per day for the quarters ended June 30, 2005 and 2004, respectively. The six month periods include revenues associated with buy/sell arrangements of $73.6 million and $81.3 million for the six month periods ended June 30, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 12,100 barrels per day and 14,300 barrels per day for the six month periods ended June 30, 2005 and 2004, respectively.

(3) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(4) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(5) The aggregate of ten systems in the West Texas/New Mexico area.

Total revenues for our pipeline segment increased for both the three and six months periods ended June 30, 2005, as compared to the same periods ended June 30, 2004. The revenue increase in the second quarter of 2005 is primarily related to our margin activities. The revenue increase in the first half of 2005 is related to both our tariff activities (see discussion below) and our margin activities. The increase in revenues from our margin activities in both periods is related to higher average prices for crude oil sold and transported on our San Joaquin Valley ("SJV") gathering system partially offset by a decrease in buy/sell volumes. Because the barrels that we buy and sell are generally indexed to the same pricing

indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Segment profit, our primary measure of segment performance, was driven by the following:

- Increased volumes and related tariff revenues—The increase in volumes and related tariff revenues during the first six months of 2005 is primarily related to the Link acquisition and other acquisitions completed during 2004. This increase primarily resulted from their inclusion for the entire 2005 period versus only a portion of the 2004 period. Tariff revenues for the second quarter of 2005 and 2004 were relatively flat, while volumes in 2005 increased approximately 9% over 2004. See further discussion below.
- Increased revenues from our loss allowance oil—As is common in the industry, our crude oil tariffs incorporate a "loss allowance factor" that is intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2%, by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on sales of allowance oil barrels are also included in tariff revenues. Increased volumes and higher crude oil prices during the second quarter and first half of 2005 as compared to the second quarter and first half of 2004 have resulted in increased revenues related to loss allowance oil, somewhat offset by losses due to the settlement of grade imbalances. The NYMEX averages were $53.23 and $51.60 for the second quarter and first half of 2005, respectively as compared to $38.28 and $36.78 for the second quarter and first half of 2004, respectively.
- Increased field operating costs—Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004, is the principal driver of the increase in field operating costs, including the LTIP charge, of $20.8 million to $72.1 million for the first half of 2005. The increased costs are primarily related to (i) payroll and benefits, (ii) emergency response and environmental remediation of pipeline releases, (iii) maintenance and (iv) utilities. In the second quarter of 2005, field operating costs increased $6.1 million to $38.0 million. The increased costs are primarily related to (i) environmental remediation of pipeline releases and (ii) utilities.
- Increased segment G&A expenses—The increase in segment G&A expenses in the first half of 2005 is primarily related to the Link acquisition coupled with the percentage of indirect costs allocated to the pipeline operations segment increasing in the 2005 period as our pipeline operations have grown in relation to our GMT&S segment. Additionally, expense related to our LTIP increased $3.5 million in the 2005 period as compared to the 2004 period. The increase in segment G&A expenses in the second quarter of 2005 as compared to the second quarter of 2004 is primarily related to the LTIP charge recognized in the 2005 period.

As discussed above, the increase in our pipeline segment profit for the first half of 2005 is largely related to our acquisition activities. We completed a number of acquisitions during the last ten months of 2004 that have impacted the results of operations herein. The following table summarizes the impact of recent acquisitions and expansions on volumes and revenues related to our tariff activities (volumes in thousands of barrels per day and revenues in millions):

	Three months ended				Six months ended			
	June 30, 2005		June 30, 2004		June 30, 2005		June 30, 2004	
	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes
Tariff activities revenues(1)(2)(3)								
2005 acquisitions/expansions	$ 4.0	114	$ —	—	$ 6.0	82	$ —	—
2004 acquisitions/expansions	33.4	694	38.6	702	71.4	695	41.9	396
All other pipeline systems	48.2	929	45.4	893	97.9	919	89.0	889
Total tariff activities	$ 85.6	1,737	$ 84.0	1,595	$ 175.3	1,696	$ 130.9	1,285

(1) Revenues include intersegment amounts.

(2) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(3) To the extent there has been an expansion to one of our existing pipeline systems, any incremental revenues and volumes are included in the results for the period that pipeline was acquired. For new pipeline systems that we construct, incremental revenues and volumes are included in the period the system became operational.

Average daily volumes from our tariff activities increased approximately 9% in the second quarter of 2005 as compared to the second quarter of 2004, while revenues were relatively flat. The increase is primarily related to the following:

- Pipeline systems that were acquired or brought into service during 2005 totaled approximately 114,000 barrels per day (approximately 84,000 barrels per day of which are attributable to our recently constructed Cushing to Broome pipeline system) and $4.0 million of revenues during the first half of 2005,
- Volumes and revenues from pipeline systems acquired in 2004 decreased in the second quarter of 2005 as compared to the second quarter of 2004, reflecting the following:

—An increase of 46,000 barrels per day and a decrease of $4.6 million in revenues from the pipelines acquired in the Link acquisition in 2005 as compared to 2004 as the volume increase was more than offset by tariff rates that were voluntarily lowered to encourage third-party shippers. Second quarter pipeline segment profit was reduced by approximately $5.0 million because of these market rate adjustments. As a result of these lower tariffs on barrels shipped by us in connection with our gathering and marketing activities, segment profit from GMT&S was increased by a comparable amount,

—A decrease of 60,000 barrels per day and $1.2 million of revenues from the pipelines acquired in the Capline acquisition in 2005 compared to 2004. Volumes on pipelines acquired in the Capline acquisition were higher than expected in the second quarter of 2004 as there was an increase in refiner demand. Volumes in the second quarter of 2005 returned to expected levels, and

—An increase in the first half of 2005 as compared to the first half of 2004 of 6,000 barrels per day and $0.6 million of revenues from other businesses acquired in the last nine months of 2004.

- All other pipeline systems (those acquired prior to 2004) reflect:

—Increased tariff rates on certain of our systems, partially related to the quality of crude oil shipped,

—The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.24 to 1 for the second quarter of 2005 compared to an average of 1.36 to 1 in the second quarter of 2004), and

—Volume increases on certain of our systems.

In the first half of 2005, average daily volumes from our tariff activities increased approximately 32% to approximately 1.7 million barrels per day and revenues from our tariff activities increased over 34% to $175.3 million. The increase in the first half of 2005 is predominately related to the inclusion of pipeline systems acquired in 2004 for the entire period versus only a portion of the period in 2004, as well as pipeline systems acquired or brought into service during 2005:

- Pipeline systems that were acquired or brought into service during 2005 totaled approximately 82,000 barrels per day and $6.0 million of revenues during the first half of 2005.

- Volumes and revenues from pipeline systems acquired in 2004 increased in the first half of 2005 as compared to the first half of 2004, reflecting the following:

—An increase in 2005 as compared to 2004 of 218,000 barrels per day and $21.5 million of revenues from the pipelines acquired in the Link acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period,

—An increase of 70,000 barrels per day and $6.3 million of revenues in 2005 as compared to 2004 from the pipelines acquired in the Capline acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period,

—An increase of 11,000 barrels per day and $1.7 million of revenues in the first half of 2005 as compared to the first half of 2004 from other businesses acquired in the last nine months of 2004.

- Revenues from all other pipeline systems (those acquired prior to 2004) also increased in the first half of 2005, along with a slight increase in volumes. The increase in revenues is related to several items including:

—Increased tariff rates on certain of our systems, partially related to the quality of crude oil shipped,

—The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.24 to 1 for the first half of 2005 compared to an average of 1.34 to 1 in the first half of 2004), and

—Volume increases on certain of our systems.

Gathering, Marketing, Terminalling and Storage Operations

As of June 30, 2005, we owned approximately 37 million barrels of active 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 14 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S segment and the balance is used in our Pipeline segment.

On a stand-alone basis, segment profit 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 thus 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. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities. We believe that this combination of our terminalling and storage activities, gathering and marketing activities and our hedging activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows. We also believe that this balance enables us to protect against downside risk while at the same time providing us with upside opportunities in volatile market conditions.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 40% and 56%in the second quarter and first half of 2005, respectively, compared to the second quarter and first half of 2004, respectively. During the same time periods, our segment profit increased almost 300% and 68%, respectively. These increases are discussed further below.

The increase in revenues for both the second quarter and first half of 2005 as compared to the same periods in 2004 was primarily because of higher crude oil prices during the 2005 periods. The average NYMEX price for crude oil was $53.23 per barrel and $51.60 per barrel for the quarter and six months ended June 30, 2005, respectively, as compared to $38.28 per barrel and $36.78 per barrel for the same periods in 2004, respectively.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period. In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our GMT&S segment for the comparative periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(in millions)			
Operating Results[1]				
Revenues[2][3]	$ 6,931.0	$ 4,941.3	$ 13,357.2	$ 8,572.6
Purchases and related costs[4]	(6,834.7)	(4,891.3)	(13,204.1)	(8,464.2)
Field operating costs (excluding LTIP charge)	(29.1)	(27.2)	(58.6)	(45.7)
LTIP charge—operations	(0.7)	—	(0.9)	(0.4)
Segment G&A expenses (excluding LTIP charge)[5]	(9.9)	(9.3)	(20.0)	(18.7)
LTIP charge—general and administrative[5]	(2.9)	—	(3.6)	(2.0)
Segment profit[3]	$ 53.7	$ 13.5	$ 70.0	$ 41.6
SFAS 133 noncash mark-to-market adjustment[3]	$ (12.9)	$ (6.9)	$ (26.3)	$ 0.5
Maintenance capital	$ 1.5	$ 0.7	$ 2.7	$ 1.0
Segment profit per barrel[6]	$ 0.91	$ 0.23	$ 0.57	$ 0.39
Average Daily Volumes (thousands of barrels per day)[7]				
Crude oil lease gathering	628	641	625	550
LPG sales	26	21	55	40

(1) Revenues and purchases and related costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $3,706.1 million and $3,450.7 million for the quarters ended June 30, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 825,000 barrels per day and 1,065,000 barrels per day for the quarters ended June 30, 2005 and 2004, respectively. Revenues associated with buy/sell arrangements were $7,125.2 million and $5,285.5 million for the six months ended June 30, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 829,000 barrels per day and 659,000 barrels per day for the six

months ended June 30, 2005 and 2004, respectively. The previously referenced amounts include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) Purchases and related costs include interest expense of $5.8 million and $0.3 million for the quarters ended June 30, 2005 and 2004, respectively, and $9.2 million and $0.4 million for the six month periods ended June 30, 2005 and 2004, respectively, on contango inventory purchases.

(5) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(6) Calculated based on crude oil lease gathered volumes and LPG sales volumes.

(7) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Segment profit for the second quarter and first half of 2005 greatly exceeded the comparable 2004 periods. The increase in the 2005 periods is partially driven by increased volumes (for the six month period) and synergies realized from businesses acquired in the last eighteen months coupled with very favorable market conditions.

The primary drivers of the current periods results were:

- Favorable market conditions—These favorable market conditions include a shift in the market structure from a backwardated market of as wide as $1.14 per barrel in late 2004 to a prolonged and pronounced contango market that has been as wide as $1.91 during the first half of 2005. The contango market structure averaged approximately $0.33 and $1.16 for the first and second quarters of 2005, respectively. Although we are normally adversely impacted by the initial transition from a backwardated market to a contango market, the market has remained in contango throughout most of the first half of 2005 and we have been able to adjust our purchases at the wellhead to both maintain our margins and remain competitive in the gathering and marketing business. In addition, we have been able to use a portion of our tankage in our terminalling and storage business to capture a significant level of profits from contango-related strategies. We have been able to do this because the market has already transitioned to a contango market and has remained there for an extended period of time.

  During the 2005 period, the market has also experienced significantly high volatility in price and market structure of crude oil. The NYMEX benchmark price of crude oil has ranged from $41.25 to $60.95 during the first half of 2005. This volatile market allowed us to utilize our hedging activities to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the quarter. Increased receipts of foreign crude oil movements at our facilities also positively impacted our results.

- Increased crude oil lease gathered volumes and LPG sales volumes—The crude oil volumes gathered from producers, using our assets or third-party assets, have increased by approximately 14% during the first half of 2005 as compared to the first half of 2004. The increase is primarily related to the Link acquisition. In addition, we marketed 38% more LPG during the first half of 2005 as compared to 2004. Crude oil lease gathered volumes and LPG sales volumes were both relatively flat in the second quarter of 2005 as compared to 2004.

- Increased tankage used in our GMT&S Operations—The positive impact of the favorable market conditions discussed above was further enhanced by the increase in the amount of tankage used in our GMT&S Operations to approximately 14 million barrels during 2005 as compared to 11 million and

12.6 million barrels in the first and second quarters of 2004, respectively.

- Decreased purchases and related costs—Lower tariffs on barrels shipped by us on certain pipelines acquired in the Link acquisition reduced purchases and related costs by approximately $5.0 million. Segment profit for our Pipeline segment was decreased by a comparable amount.
- Increased field operating costs—Our continued growth, primarily from the Link acquisition, is the primary driver of the increase in field operating costs for the first half of 2005 as compared to the first half of 2004. The increased costs are pimarily related to (i) payroll and benefits and (ii) fuel.

The 2005 period also includes a noncash mark-to-market adjustment loss of $12.9 million pursuant to SFAS 133 that was recognized in the second quarter compared to a net loss of $6.9 million in the second quarter of 2004. In addition, we recognized a net loss of $26.3 million in the first half of 2005 pursuant to SFAS 133 compared to a net gain of $0.5 million in the first half of 2004. The primary components of the $26.3 million noncash adjustment in 2005 were:

- A decrease in the mark-to-market of approximately $20.3 million resulting from the change in fair value for option and futures contracts that serve to reduce our lease gathering and tankage business exposures. Because the tankage arrangements will not necessarily result in physical delivery, they are not eligible for hedge accounting treatment under SFAS 133. In addition, because our option activity often involves option sales, these also do not receive hedge accounting treatment. While these derivatives do not qualify for hedge accounting, their purpose is to mitigate risk associated with our physical assets in our storage and terminalling activities and contractual arrangements in our lease gathering activities. A portion of the decrease in fair value during the current period relates to the settlement of mark-to-market gains from the previous period. Total settlements related to these strategies during the first half of 2005 were $11.7 million.
- A decrease in the mark-to-market of approximately $6.9 million resulting from the change in fair value of our Canadian and LPG derivative contracts, which do not consistently qualify for hedge accounting because the correlations tend to fluctuate. These positions primarily consist of hedges of stored inventory and purchase commitments. The loss in the current period primarily results from the impact of rising prices. A portion of the decrease in fair value during the current period relates to the settlement of mark-to-market gains from the previous period. Total settlements related to these strategies during the first half of 2005 were $1.0 million.
- An increase in the mark-to-market of $0.9 million primarily related to the change in fair value of certain derivative instruments used to minimize the risk of unfavorable changes in exchange rates. A portion of the increase in fair value during the current period relates to the settlement of mark-to-market losses from the previous period. Total settlements related to these derivatives during the first half of 2005 were $1.3 million.

Segment profit per barrel (calculated based on our lease gathered crude oil and LPG volumes) was $0.91 per barrel for the quarter ended June 30, 2005, compared to $0.23 for the quarter ended June 30, 2004. Segment profit per barrel was $0.57 for the first half of 2005, compared to $0.39 per barrel for the first half of 2004. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will continue to remain as favorable as have recently been experienced, and operating results may not be indicative of sustainable performance.

Other Expenses

Depreciation and Amortization

Depreciation and amortization expense increased approximately $9.5 million to $38.6 million in the first half of 2005. The increase relates primarily to the assets from our 2004 acquisitions being included for the entire period in 2005 versus only a part of the period in 2004. Additionally, several capital projects

were completed during mid-to-late 2004 that were not included in first half of 2004 depreciation expense. The increase of $3.4 million to $19.4 million in the second quarter of 2005 is primarily related to the capital projects completed in 2004, as previously mentioned. Amortization of debt issue costs was $0.7 million and $1.3 million in the second quarter and first half of 2005, respectively, and was relatively flat compared to the corresponding periods in 2004.

Interest Expense

Interest expense is primarily impacted by:

- our average debt balances,
- the level and maturity of fixed rate debt, and
- interest rates associated therewith, market interest rates and our interest rate hedging activities on floating rate debt.

The following table summarizes the components of our average debt balances:

	For the three months ended June 30,		For the six months ended June 30,	
	2005	2004	2005	2004
	(average amount outstanding, in millions)			
Fixed rate senior notes[(1)]	$ 863	$ 450	$ 832	$ 450
Borrowings under our revolving credit facilities[(2)]	163	493	187	321
Total	$ 1,026	$ 943	$ 1,019	$ 771

(1) Weighted average face amount of senior notes, exclusive of discounts.

(2) Excludes borrowings under our senior secured hedged inventory facility and other contango inventory-related borrowings.

The higher average debt balance in both of the 2005 periods was primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.2% for both of the 2005 periods, compared to 4.2% and 4.9% for the second quarter and first half of 2004, respectively.

The net impact of the items discussed above was an increase in interest expense in the second quarter of 2005 of approximately $4.3 million to a total of $14.3 million. In the first half of 2005, interest expense increased $9.3 million to $28.8 million. The increase in interest expense in the second quarter of 2005 is primarily related to the increase in our weighted average interest rate, along with the increase in our average debt balance. The increase in interest expense in the first half of 2005 is related to both the increase in our average debt balance and the increase in our weighted average interest rate.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our GMT&S segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $5.8 million and $9.2 million for the second quarter and first half of 2005, respectively. In 2004, these costs were approximately $0.3 million and $0.4 million for the second quarter and first half, respectively.

Outlook

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.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of transportation, gathering, terminalling or storage assets and related midstream crude-oil businesses. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass other midstream businesses to which such resources effectively can be applied. We are presently engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses described above, but we can give 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.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At June 30, 2005, we had a working capital deficit of approximately $121.5 million, approximately $618.7 million of availability under our committed revolving credit facilities and approximately $144.3 million of availability under our uncommitted hedged inventory facility (see “Capital Resources” below). Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

Capital Resources

In July 2005, we 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 $2 billion of debt or equity securities.

During May 2005, we completed the sale of $150 million of 5.25% Senior Notes due 2015. The notes were sold at 99.518% of face value. We used the net proceeds of approximately $148 million, after deducting initial purchaser discounts and offering costs, to repay amounts outstanding under our credit facilities and for general partnership purposes.

In May 2005, we amended our senior unsecured credit facility to increase the capacity from $750 million to $900 million and increased the sub-facility for Canadian borrowings to $360 million. The amended facility can be expanded to $1.25 billion, subject to obtaining additional lender commitments. Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million.

In February 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner’s proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. Although the net proceeds were used to repay indebtedness under our revolving credit facilities at closing, they will ultimately be used to fund a portion of our 2005 expansion capital program as these expenditures are incurred.

Capital Expenditures

We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations, credit facility borrowings, the issuance of senior unsecured notes and the sale of additional common units.

We expect to spend approximately $190 million on expansion capital projects during 2005. This includes our original estimate of expansion capital and newly announced projects, the most notable of which is our recently announced construction of a St. James, Louisiana storage facility. The St. James facility has an estimated total project cost of approximately $85 million, of which approximately $21 million will be spent in 2005. Our 2005 expansion capital projects include the following notable projects with the estimated cost for the entire year.

	2005 Total (in millions)
St. James, Louisiana storage facility	$ 21.0
Trenton pipeline expansion	$ 34.0

Capital projects associated with the Link acquisition	$ 18.0
NW Alberta fractionator	$ 16.0
Cushing Phase V expansion	$ 13.0
Kerrobert Tank expansion	$ 9.0
Shell South Louisiana asset acquisition	$ 8.0

Approximately $73 million of our forecasted expansion capital was incurred as of June 30, 2005. Capital expenditures for maintenance projects are forecast to be approximately $19 million during 2005, of which approximately $8 million was incurred in the first six months.

We believe that we have sufficient liquid assets, cash flow 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 affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Cash Flows

	Six Months Ended June 30,	
	2005	**2004**
	(in millions)	
Cash provided by (used in):		
Operating activities	$ (453.4)	$ 147.1
Investing activities	(97.4)	(474.6)
Financing activities	576.6	334.0

Operating Activities. The primary drivers of our cash flow from operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the

subsequent period that we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow on our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operating activities increases in the period we collect the cash from the sale of the stored crude oil. Similarly, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end. Cash flow used in operating activities was $453.4 million in the 2005 period. Cash flow provided by operating activities was $147.1 million in the 2004 period.

Cash flows from operating activities in 2005 reflects the purchase and storage of crude oil because of contango market conditions. During the first half of 2005, we purchased crude oil for storage. These purchases had a negative impact on cash flows from operating activities when the invoices for the crude oil were paid. The proceeds we received from our credit facilities to pay for the crude oil while stored are shown as financing activities in the cash flow statement. As such, until we deliver the crude oil and receive payment from our customers, operating activities in the cash flow statement will be negatively impacted by this activity. Crude oil stored is hedged against price risk.

Investing Activities. Net cash used in 2005 was $97.4 million and was predominantly related to additions to property and equipment comprised of (i) $22.6 million paid for our Trenton pipeline expansion, (ii) $12.1 million paid for our Cushing to Broome pipeline expansion, (iii) $6.0 million paid for our Cushing Phase V expansion, and (iv) various other projects totaling approximately $45.6 million. Additionally, approximately $14.5 million was paid for various acquisitions. Net cash used in 2004 was $474.6 million and was primarily comprised of (i) $142.3 million paid for the Capline and Capwood Pipeline Systems acquisition (a deposit had been paid in December 2003), (ii) approximately $280 million paid for the Link acquisition, (iii) approximately $19 million paid for the CalVen acquisition and (iv) $32.2 million paid for additions to property and equipment.

Financing Activities. Cash provided by financing activities in the first half of 2005 was approximately $576.6 million, primarily consisting of:

- approximately $149.3 million of proceeds from the sale of senior notes,
- approximately $22.3 million of proceeds from a private placement of common units,
- net short and long-term repayments under our revolving credit facility of approximately $71.8 million,
- net borrowings under our short-term letter of credit and hedged inventory facility of approximately $575.3 million for the purchase of crude oil inventory that was stored (see “Operating Activities” above), and
- $92.7 million of distributions paid to common unitholders and the general partner.

Cash provided by financing activities in the first half of 2004 was approximately $334.0 million, primarily consisting of:

- approximately $101.2 million of proceeds from the issuance of Class C common units,
- net short and long-term borrowings under our revolving credit facility of approximately $403.7 million used primarily to fund the purchase price of the Capline and Link acquisitions,
- net repayments under our short-term letter of credit and hedged inventory facility of approximately $96.1 million resulting from the collection of receivables related to prior year sales of inventory that was stored because of contango market conditions, and
- $72.7 million of distributions paid to common unitholders and the general partner.

Contingencies

See Note 9 “Commitments and Contingencies” in “Notes to the Consolidated Financial Statements.”

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to credit worthy entities.

The following table includes our best estimate of the amount and timing of payments due under specified contractual obligations as of June 30, 2005.

	2005	2006	2007	2008	2009	Thereafter
			(in millions)			
Long-term debt and interest payments[1]	$ 28.8	$ 57.5	$ 57.5	$ 57.5	$ 232.3	$ 997.0
Leases[2]	9.2	14.7	12.2	9.6	8.5	48.3
Capital expenditure obligations	15.0	—	—	—	—	—
Other long-term liabilities[3]	—	4.0	9.7	1.7	5.9	2.6
Subtotal	53.0	76.2	79.4	68.8	246.7	1,047.9
Crude oil and LPG purchases[3][4]	2,174.4	166.6	102.6	102.6	102.5	17.0
Total	$ 2,227.4	$242.8	$182.0	$171.4	$ 349.2	$ 1,064.9

(1) Includes debt service payments, interest payments due on our senior notes, interest payments due on the long-term portion of our revolving credit facility currently outstanding and the commitment fee on the portion of our revolving credit facility that is currently not utilized. The interest amount calculated on the long-term portion of our revolving credit facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Approximately $6.5 million of non-current liabilities related to SFAS 133 are included in the crude oil and LPG purchases section of this table.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At June 30, 2005, we had outstanding letters of credit under our various facilities of approximately $121.3 million.

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 of our management 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 our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, counter parties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws, rulings and governmental regulations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;

- the currency exchange rate of the Canadian dollar;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plan; and
- general economic, market or business conditions.

Other factors, such as the “Risk Factors Related to Our Business” 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 2004 Annual Report on Form 10-K. There have not been any material changes in that information other than those discussed below.

Commodity Price Risk

All of our open commodity price risk derivatives at June 30, 2005 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below:

	Fair Value	Effect of 10% Price Change
	(in millions)	
Crude oil:		
Futures contracts	$ (60.2)	$ (14.7)
Swaps and options contracts	$ (12.2)	$ (7.8)
LPG:		
Swaps and options contracts	$ (0.9)	$ 0.7

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at June 30, 2005. All of our outstanding senior notes are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. The average interest rates presented below are based upon rates in effect at June 30, 2005. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates.

	Expected Year of Maturity						
	2005	2006	2007	2008	2009	Thereafter	Total
				(in millions)			
Liabilities:							
Short-term debt—variable rate	$ 815.7	$ —	$ —	$ —	$ —	$ —	$815.7
Average interest rate	4.0%	—	—	—	—	—	4.0%
Long-term debt—variable rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Average interest rate	—	—	—	—	—	—	—

Item 4. CONTROLS AND PROCEDURES

We maintain “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.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and

Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of June 30, 2005, 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 (“internal control”) that occurred during the second quarter and that has materially affected, or is reasonably likely to materially affect, our internal control. There are none. However, in the process of documenting and testing our internal control in connection with compliance with Rule 13a-15(c) under the Exchange Act of 1934, as amended (required by Section 404 of the Sarbanes-Oxley Act of 2002) we have made changes, and will continue to make changes, to refine and improve our internal control.

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

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the “short supply” controls of the Export Administration Regulations (“EAR”) and must be licensed by the Bureau of Industry and Security (the “BIS”) of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of our personnel, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.5 million to $4.0 million. We continue to work with the appropriate state and federal environmental authorities with respect to site restoration and no enforcement proceedings have been instituted by any governmental authority at this time.

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. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None

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

See Item 4. “Submission of Matters to a Vote of Security Holders” in our 2004 Annual Report on Form 10-K.

Item 5. OTHER INFORMATION

Pending Reallocation of General Partner Interest

One of the owners of our general partner has provided notice that it intends to sell its 19% interest in the general partner. The remaining owners have elected to exercise their right of first refusal, such that the 19% interest will be allocated prorata to all remaining owners. As a result, subject to consummation of the transaction, the interest of Vulcan Energy Corporation will increase from 44% to approximately 54%. We anticipate that, at closing, Vulcan will enter into a voting agreement that will restrict its ability to unilaterally elect or remove our independent directors, and our CEO and COO will agree to waive certain change-of-control payment rights that would otherwise be triggered by the increase in Vulcan’s ownership interest.

Item 6. EXHIBITS

4.1	Fifth Supplemental Indenture, dated as of May 27, 2005, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P. and PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed May 31, 2005)
10.1	First Amendment to Restated Credit Agreement dated as of April 20, 2005, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 21, 2005)
10.2	Second Amendment to Restated Credit Agreement dated as of May 11, 2005, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 12, 2005)
10.3	Second Amendment, dated as of May 6, 2005, to the Credit Agreement dated November 2, 2004 among Plains All American Pipeline, L.P. (as US Borrower), PMC (Nova Scotia) Company and Plains Marketing Canada, L.P. (as Canadian Borrowers), and Bank of America, N.A. (incorporated by reference to Exhibit 10.2 to Form 10-Q for the period ended March 31, 2005)
10.4	Registration Rights Agreement, dated May 27, 2005, among Plains All American Pipeline, L.P., PAA Finance Corp. Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., J.P. Morgan Securities Inc. and

	Wachovia Capital Markets, LLC, Citigroup Global Markets Inc., UBS Securities LLC, Banc of America Securities LLC, Scotia Capital (USA) Inc., SunTrust Capital Markets, Inc,. Fortis Securities LLC, Daiwa Securities America Inc., SG Americas Securities, LLC and RBC Capital Markets Corporation (incorporated by reference to Exhibit 4.1 to Form 8-K filed May 31, 2005)
†31.1	Certification of Principal Executive Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
†31.2	Certification of Principal 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

† Filed herewith.

* Furnished herewith.

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 5, 2005

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 5, 2005

By: /s/ PHIL KRAMER

Phil Kramer, *Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)*

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (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 the period covered by this 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 5, 2005

/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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (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 the period covered by this 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 5, 2005

/s/ PHIL KRAMER

Phil Kramer

Chief Financial Officer

EXHIBIT 32.1

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, 2005 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 5, 2005

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, 2005 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 5, 2005