PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
May 09, 2007

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

FORM 10-Q

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

For the quarterly period ended March 31, 2007

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 þ No o

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

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes þ No

At May 1, 2007, there were outstanding 109,405,178 Common Units.

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	March 31, 2007	December 31, 2006
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 16.6	$ 11.3
Trade accounts receivable and other receivables, net	1,665.3	1,725.4
Inventory	968.2	1,290.0
Other current assets	159.4	130.9
Total current assets	2,809.5	3,157.6
PROPERTY AND EQUIPMENT	4,343.5	4,190.1
Accumulated depreciation	(384.8)	(348.1)
	3,958.7	3,842.0
OTHER ASSETS		
Pipeline linefill in owned assets	271.0	265.5
Inventory in third-party assets	76.0	75.7
Investment in unconsolidated entities	195.7	183.0
Goodwill	1,035.1	1,026.2
Other, net	167.0	164.9
Total assets	$ 8,513.0	$ 8,714.9
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,723.3	$ 1,846.6
Short-term debt	900.9	1,001.2
Other current liabilities	226.4	176.9
Total current liabilities	2,850.6	3,024.7
LONG-TERM LIABILITIES		

Long-term debt under credit facilities and other	3.0	3.1
Senior notes, net of unamortized net discount of $1.9 and $1.8, respectively	2,623.1	2,623.2
Other long-term liabilities and deferred credits	92.7	87.1
Total long-term liabilities	2,718.8	2,713.4
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS CAPITAL		
Common unitholders (109,405,178 units outstanding at March 31, 2007 and December 31, 2006)	2,873.5	2,906.1
General partner	70.1	70.7
Total partners capital	2,943.6	2,976.8
Total liabilities and partners capital	$ 8,513.0	$ 8,714.9

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended March 31, 2007	2006
	(unaudited)	
REVENUES		
Crude oil, refined products and LPG sales and related revenues (includes buy/sell transactions of $4,761.9 in the first quarter of 2006)	$ 4,116.7	$ 8,575.3
Pipeline tariff activities revenues	86.7	57.4
Other revenues	26.1	2.4
Total revenues	4,229.5	8,635.1
COSTS AND EXPENSES		
Crude oil, refined products and LPG purchases and related costs (includes buy/sell transactions of $4,795.1 in the first quarter of 2006)	3,899.6	8,424.5
Field operating costs	125.7	85.2
General and administrative expenses	46.8	31.8
Depreciation and amortization	39.9	21.6
Total costs and expenses	4,112.0	8,563.1
OPERATING INCOME	117.5	72.0
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	3.6	0.1
Interest expense (net of capitalized interest of $2.8 and $0.6)	(41.1)	(15.3)
Interest income and other income (expense), net	4.8	0.3
Income tax expense	(0.1)	
Income before cumulative effect of change in accounting principle	84.7	57.1
Cumulative effect of change in accounting principle		6.3
NET INCOME	$ 84.7	$ 63.4
NET INCOME-LIMITED PARTNERS	$ 67.9	$ 56.7
NET INCOME-GENERAL PARTNER	$ 16.8	$ 6.7
BASIC NET INCOME PER LIMITED PARTNER UNIT		
Income before cumulative effect of change in accounting principle	$ 0.62	$ 0.65
Cumulative effect of change in accounting principle		0.08

Net income	$	0.62	$	0.73
DILUTED NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$	0.61	$	0.63
Cumulative effect of change in accounting principle				0.08
Net income	$	0.61	$	0.71
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		109.4		74.0
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		110.7		75.7

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

4

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 84.7	$ 63.4
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	39.9	21.6
Cumulative effect of change in accounting principle		(6.3)
SFAS 133 mark-to-market adjustment	17.0	0.7
Inventory valuation adjustment	1.0	
Gain on sale of investment assets	(3.9)	
Long-Term Incentive Plan charge	18.6	10.6
Noncash amortization of terminated interest rate hedging instruments	0.2	0.4
(Gain)/loss on foreign currency revaluation	(0.2)	0.9
Equity earnings in unconsolidated entities	(3.6)	(0.1)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	60.7	(430.9)
Inventory	323.3	(116.0)
Accounts payable and other liabilities	(173.1)	(3.2)
Due to related parties	7.1	1.3
Net cash provided by (used in) operating activities	371.7	(457.6)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 3)	(17.3)	(17.5)
Additions to property and equipment	(134.1)	(62.7)
Investment in unconsolidated entities	(9.1)	
Cash paid for linefill in assets owned	(4.5)	(4.3)
Proceeds from sales of assets	4.3	0.2
Net cash used in investing activities	(160.7)	(84.3)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on working capital revolving credit facility	(69.9)	(5.1)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	(32.1)	503.4
Net proceeds from the issuance of common units (Note 7)		101.4
Distributions paid to unitholders and general partner (Note 7)	(104.6)	(57.3)
Other financing activities	(0.2)	(0.9)
Net cash provided by (used in) financing activities	(206.8)	541.5

Effect of translation adjustment on cash		1.1		0.1
Net increase (decrease) in cash and cash equivalents		5.3		(0.3)
Cash and cash equivalents, beginning of period		11.3		9.6
Cash and cash equivalents, end of period	$	16.6	$	9.3
Cash paid for interest, net of amounts capitalized	$	26.3	$	17.5
Cash paid for income taxes	$	1.6	$	

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(in millions)

	Common Units		General Partner	Total Partners Capital
	Units	Amount	Amount	Amount
		(unaudited)		
Balance at December 31, 2006	**109.4**	**$ 2,906.1**	**$ 70.7**	**$ 2,976.8**
Net income		67.9	16.8	**$ 84.7**
Distributions		(87.5)	(17.1)	**$ (104.6)**
Other comprehensive income		(13.0)	(0.3)	**$ (13.3)**
Balance at March 31, 2007	**109.4**	**$ 2,873.5**	**$ 70.1**	**$ 2,943.6**

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended March 31,	
	2007	2006
	(unaudited)	
Net income	$ 84.7	$ 63.4
Other comprehensive income/(loss)	(13.3)	0.5
Comprehensive income	$ 71.4	$ 63.9

CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2006	$ (19.8)	$ 69.5	$ 49.7
Reclassification adjustments for settled contracts	(23.5)		(23.5)
Changes in fair value of outstanding hedge positions	4.6		4.6
Currency translation adjustment		5.6	5.6
Total period activity	(18.9)	5.6	(13.3)
Balance at March 31, 2007	$ (38.7)	$ 75.1	$ 36.4

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

Table of Contents

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

Note 1 Organization and Accounting Policies

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-Q, the terms Partnership, Plains, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its sub unless the context indicates otherwise.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as LPG. Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we develop and operate natural gas storage facilities.

Our 2% general partner interest is held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P. s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and employees are employed by our subsidiary PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. Unless the context otherwise requires, we use the term general partner to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 54.3% to 1.2%.

The consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2006 Annual Report on Form 10-K. The accompanying financial statements and related notes present (i) our consolidated financial position as of March 31, 2007 and December 31, 2006, (ii) the results of our consolidated operations for the three months ended March 31, 2007 and 2006, (iii) our consolidated cash flows for the three months ended March 31, 2007 and 2006, (iv) our consolidated changes in partners capital for the three months ended March 31, 2007, (v) our consolidated comprehensive income for the three months ended March 31, 2007 and 2006, and (vi) our changes in consolidated accumulated other comprehensive income for the three months ended March 31, 2007. 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 three months ended March 31, 2007 should not be taken as indicative of the results to be expected for the full year.

The accompanying consolidated financial statements of PAA include PAA and all of its subsidiaries, which are wholly owned. Investments in 50% or less owned entities over which we have significant influence but not control are accounted for by the equity method. During the first quarter of 2007 we made an additional contribution of approximately $9 million to PAA/Vulcan. We evaluate our equity investments for impairment in accordance with Accounting Principles Board (APB) 18: *The Equity Method of Accounting for Investments in Common Stock.* An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

Note 2 Trade Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG. The majority of our accounts receivable relate to our marketing activities, which can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or parental guarantees. At March 31, 2007 and December 31, 2006, we had received approximately $16.8 million and $28.3 million, respectively, of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

Table of Contents

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At March 31, 2007 and December 31, 2006, substantially all of our net accounts receivable classified as current were less than 60 days past their scheduled invoice date. Although we consider our allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts. Our allowance for doubtful accounts balance was $0.7 million at March 31, 2007 and at December 31, 2006.

Note 3 Acquisitions

During the first quarter of 2007, we acquired (i) certain commercial refined products supply and marketing businesses (which is reflected in our marketing segment) for approximately $8 million in cash (including approximately $7 million of goodwill) and (ii) a trucking business (which is reflected in our transportation segment) for approximately $9 million in cash (including approximately $4 million of goodwill). Also, during the first quarter of 2007, we signed an agreement to acquire the Bumstead LPG storage facility located near Phoenix, Arizona for approximately $52 million. The acquisition is expected to close early in the second half of 2007 and will be reflected in our facilities segment.

Note 4 Inventory and Linefill

Inventory primarily consists of crude oil, refined products 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 assets we own are recorded at historical cost and consist of crude oil and LPG used to pack the pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

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 inventory 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.

Table of Contents

At March 31, 2007 and December 31, 2006, inventory and linefill consisted of :

	March 31, 2007			December 31, 2006		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory [1]						
Crude oil	15,470	$ 871.0	$ 56.30	18,331	$ 1,029.1	$ 56.14
LPG	1,919	81.9	$ 42.68	5,818	250.7	$ 43.09
Refined products	84	6.1	$ 72.62	81	3.8	$ 46.91
Parts and supplies	N/A	9.2	N/A	N/A	6.4	N/A
Inventory subtotal	17,473	968.2		24,230	1,290.0	
Inventory in third-party assets						
Crude oil	1,241	63.0	$ 50.77	1,212	62.5	$ 51.57
LPG	318	13.0	$ 40.88	318	13.2	$ 41.51
Inventory in third-party assets subtotal	1,559	76.0		1,530	75.7	
Pipeline linefill in owned assets						
Crude oil	7,867	269.0	$ 34.19	7,831	264.4	$ 33.76
LPG	53	2.0	$ 37.74	31	1.1	$ 35.48
Pipeline linefill in owned assets subtotal	7,920	271.0		7,862	265.5	
Total	26,952	$ 1,315.2		33,622	$ 1,631.2	

(1) Includes the impact of inventory hedges on a portion of our volumes.

9

Note 5 Debt

Below is a description of our debt as of March 31, 2007:

	March 31, 2007	December 31, 2006
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.8% and 5.8% at March 31, 2007 and December 31, 2006, respectively	$ 803.2	$ 835.3
Working capital borrowings, bearing interest at a rate of 6.0% and 5.9% at March 31, 2007 and December 31, 2006, respectively (1)	90.2	158.2
Other	7.5	7.7
Total short-term debt	900.9	1,001.2
Long-term debt:		
4.75% senior notes due August 2009, net of unamortized discount of $0.4 million and $0.4 million at March 31, 2007 and December 31, 2006, respectively	174.6	174.6
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.2 million at March 31, 2007 and December 31, 2006, respectively	199.8	199.8
5.63% senior notes due December 2013, net of unamortized discount of $0.4 million and $0.5 million at March 31, 2007 and December 31, 2006, respectively	249.6	249.5
7.13% senior notes due June 2014, net of unamortized premium of $8.4 million and $8.8 million at March 31, 2007 and December 31, 2006, respectively	258.4	258.8
5.25% senior notes due June 2015, net of unamortized discount of $0.6 million and $0.6 million at March 31, 2007 and December 31, 2006, respectively	149.4	149.4
6.25% senior notes due September 2015, net of unamortized discount of $0.8 million and $0.8 million at March 31, 2007 and December 31, 2006, respectively	174.2	174.2
5.88% senior notes due August 2016, net of unamortized discount of $0.9 million and $0.9 million at March 31, 2007 and December 31, 2006, respectively	174.1	174.1
6.13% senior notes due January 2017, net of unamortized discount of $1.7 million and $1.8 million at March 31, 2007 and December 31, 2006, respectively	398.3	398.2
6.70% senior notes due May 2036, net of unamortized discount of $0.4 million and $0.4 million at March 31, 2007 and December 31, 2006, respectively	249.6	249.6
6.65% senior notes due January 2037, net of unamortized discount of $4.9 million and $5.0 million at March 31, 2007 and December 31, 2006, respectively	595.1	595.0

Senior notes, net of unamortized discount [2]	2,623.1	2,623.2
Long-term debt under credit facilities and other	3.0	3.1
Total long-term debt [1][2]	2,626.1	2,626.3
Total debt	$ 3,527.0	$ 3,627.5

(1) At March 31, 2007 and December 31, 2006, we have classified $90.2 million and $158.2 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 inventory and New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin deposits.

(2) At March 31, 2007, the aggregate fair value of our fixed rate senior notes is estimated to be approximately $2,689.1 million. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

Letters of Credit. In connection with our crude oil marketing business and as is customary in our industry, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and 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 periods of up to seventy days and are terminated upon completion of each transaction. At March 31, 2007, approximately $120.0 million of letters of credit under our credit facility were outstanding.

Table of Contents

Note 6 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. Subject to applicability of Emerging Issues Task Force Issue No. 03-06 (EITF 03-06), Participating Securities and the Two-Class Method under Financial Accounting Standards Board (FASB) Statement No. 128, as discussed below, 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.

EITF 03-06 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 (or partnership distributions to unitholders). 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 is allocated (as if distributed) to 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.

Table of Contents

The following sets forth the computation of basic and diluted earnings per limited partner unit.

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Numerator:		
Net income	$ 84.7	$ 63.4
Less: General partner s incentive distribution paid	(15.3)	(5.5)
Subtotal	69.4	57.9
Less: General partner 2% ownership	(1.5)	(1.2)
Net income available to limited partners	67.9	56.7
Less: EITF 03-06 additional general partner s distribution		(2.9)
Net income available to limited partners under EITF 03-06	$ 67.9	$ 53.8
Less: Limited partner 98% portion of cumulative effect of change in accounting principle		(6.2)
Limited partner net income before cumulative effect of change in accounting principle	$ 67.9	$ 47.6
Denominator:		
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	109.4	74.0
Effect of dilutive securities:		
LTIP units outstanding (1)	1.3	1.7
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	110.7	75.7
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.62	$ 0.65
Cumulative effect of change in accounting principle per limited partner unit		0.08
Basic net income per limited partner unit	$ 0.62	$ 0.73
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.61	$ 0.63
Cumulative effect of change in accounting principle per limited partner unit		0.08
Diluted net income per limited partner unit	$ 0.61	$ 0.71

(1) Our LTIP awards that contemplate the issuance of common units

described in Note 8 are considered dilutive securities unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in Statement of Financial Accounting Standards (SFAS) No. 128, Earnings per Share.

Note 7 Partners Capital and Distributions

On April 17, 2007, we declared a cash distribution of $0.8125 per unit on our outstanding common units. The distribution is payable on May 15, 2007, to unitholders of record on May 4, 2007, for the period January 1, 2007 through March 31, 2007. The total distribution to be paid is approximately $107.4 million, with approximately $88.9 million to be paid to our common unitholders and approximately $1.8 million and $16.7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

On January 16, 2007, we declared a cash distribution of $0.80 per unit on our outstanding common units. The distribution was paid on February 14, 2007 to unitholders of record on February 2, 2007, for the period October 1, 2006 through December 31, 2006. The total distribution paid was approximately $104.6 million, with approximately $87.5 million paid to our common unitholders and $1.8 million and $15.3 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Upon closing of the acquisition of Pacific Energy Partners L.P. (Pacific) in November 2006, our general partner agreed to reduce the amount of its incentive distributions as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. Pursuant to this agreement, the first quarterly reduction of $5 million occurred with the incentive distribution paid to the general partner on February 14, 2007. The incentive distribution to be paid in May 2007 also reflects a reduction of $5 million. The total reduction in incentive distributions will be $65 million.

Note 8 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan, the 2005 Long-Term Incentive Plan and the PPX Successor Long-Term Incentive Plan for employees and directors and the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan for non-officer employees, collectively referred to as Long-Term Incentive Plans (LTIP). The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the grant of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to phantom units, which mature into the right to receive common units (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights (DERs). Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit prior to the vesting date of the underlying award. The 2006 Plan authorizes the grant of approximately 1.4 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a Common Unit at the time of vesting. Our general partner is entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

We adopted SFAS 123(R) on January 1, 2006. Under SFAS 123(R) the fair value of the awards, which are subject to liability classification, is calculated based on the market price of our units at the balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is then recognized as compensation expense over the period the awards are earned. For awards with performance conditions, we recognize LTIP compensation expense only if the achievement of the performance condition is considered probable. When awards with performance conditions that were previously considered improbable of occurring become probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with these awards. In addition, we recognize compensation expense for DER payments in the period the payment is earned.

As of March 31, 2007, there were outstanding awards of approximately 4.4 million phantom units and tracking units with a weighted average grant-date fair value of approximately $36.92 per unit. Our LTIP awards typically contain performance conditions relative to our annualized distribution level and vest upon the latter of a certain date or upon the attainment of a certain annualized distribution level. Upon our February 2007 annualized distribution of $3.20, approximately 2.2 million of our outstanding awards satisfied all performance conditions necessary for vesting and will vest in various increments over the next 5 years. Approximately 0.7 million of these awards will vest in May 2007. Approximately 2.2 million of our remaining outstanding awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00, which is not yet considered probable of occurring. Provided the performance conditions associated with these awards are ultimately attained, these awards will vest in various increments between 2010 and 2014. However, subject to continued employment, approximately 0.4 million of these awards still outstanding in 2012 will vest regardless of whether or not the performance condition is attained. Approximately 3.0 million of our outstanding awards include DERs, of which 1.6 million are currently vested. Our DER awards typically contain performance conditions relative to our annualized distribution level and vest upon the earlier of a certain date or a certain annualized distribution level. The DERs terminate with the vesting or forfeiture of the underlying award.

Our LTIP activity is summarized in the following table (in millions except weighted average grant date fair values per unit):

	Units	Weighted Average Grant Date Fair Value per unit
Outstanding at December 31, 2006	3.0	$ 31.94
Granted	1.4	$ 47.42
Vested		$
Cancelled or forfeited		$
Outstanding at March 31, 2007	4.4	$ 36.92

Table of Contents

We recognized expense related to our LTIP of approximately $19 million and $10 million during the first quarter of 2007 and 2006, respectively. Approximately $8.4 million of the charge for the first quarter of 2007 is associated with the Partnership s unit price increasing from $51.20 at December 31, 2006 to $57.61 at March 31, 2007. As of March 31, 2007, we have an accrued liability of approximately $74.8 million associated with our LTIP. Cash payments associated with LTIP vestings were approximately $1 million in the first quarter of 2006. There were no material payments in the first quarter of 2007. Cash payments associated with DER awards were approximately $1 million and $1 million in the first quarter of 2007 and 2006, respectively. No units were issued during the first quarter of 2007 in connection with the settlement of vested awards.

As of March 31, 2007, the weighted average remaining contractual life of our outstanding awards (that are currently considered probable of vesting) was approximately 2.5 years based on expected vesting dates. Based on the March 31, 2007 fair value measurement and probability assessment regarding future distributions, we expect to recognize an additional $65 million of expense over the life of our outstanding awards related to the remaining unrecognized fair value. This estimate is based on the market price of our limited partner units of $57.61 at March 31, 2007. Actual amounts may differ materially as a result of a change in market price. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	LTIP Fair Value Amortization(1)
2007 (2)	$ 19.4
2008	20.3
2009	14.1
2010	5.9
2011	2.7
2012	2.4
Total	$ 64.8

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at March 31, 2007.

(2) Includes LTIP fair value amortization for the remaining nine months of 2007.

Note 9 Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled commodity 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, and NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to help ensure that our hedging activities address our market risks. Our policy is to 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 or the fair value of 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, refined products, LPG and natural gas as well as with respect to expected purchases, sales and transportation of these commodities. 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 (AOCI) 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 SFAS No. 133, Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133)) in offsetting changes in cash flows of the hedged items, are marked-to-market in revenues each period.

Table of Contents

The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, the ICE and over-the-counter, including commodity swap and option contracts entered into with financial institutions and other energy companies.

A summary of the earnings impact of all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the first quarter of 2007 and the first quarter of 2006, is as follows (in millions, losses designated in brackets):

	For the Three Months Ended March 31, 2007			For the Three Months Ended March 31, 2006		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price-risk hedging	$ (19.1)	$ 69.8	$ 50.7	$ (0.7)	$ 6.2	$ 5.5
Controlled trading program		0.1	0.1			
Interest rate risk hedging		(0.2)	(0.2)		(0.4)	(0.4)
Currency exchange rate risk hedging	2.1	(1.0)	1.1		0.6	0.6
Total	$ (17.0)	$ 68.7	$ 51.7	$ (0.7)	$ 6.4	$ 5.7

The breakdown of the net mark-to-market impact to earnings between derivatives that do not qualify for hedge accounting and the ineffective portion of cash flow hedges is as follows (in millions, losses designated in brackets):

	For the Three Months Ended	
	March 31, 2007	March 31, 2006
Derivatives that do not qualify for hedge accounting	$ (16.5)	$ (0.8)
Ineffective portion of cash flow hedges	(0.5)	0.1
Total	$ (17.0)	$ (0.7)

Derivatives that do not qualify for hedge accounting consist of (i) derivatives that are an effective element of our risk management strategy but are not consistently effective to qualify for hedge accounting pursuant to SFAS 133 and (ii) derivatives associated with our storage assets as these contracts will not necessarily result in physical delivery.

The following table summarizes the net assets and liabilities on our consolidated balance sheet that are related to the fair value of our open derivative positions (in millions):

	March 31, 2007	December 31, 2006
Other current assets	$ 89.2	$ 55.2
Other long-term assets	6.4	9.0
Other current liabilities	(143.6)	(77.3)
Other long-term liabilities and deferred credits	(22.6)	(21.4)
Net asset (liability)	$ (70.6)	$ (34.5)

The net liability related to the fair value of our open derivative positions consists of cumulative unrealized gains/losses recognized in earnings and cumulative unrealized gains/losses deferred to AOCI as follows, by category (in millions, losses designated in brackets):

	March 31, 2007			December 31, 2006		
	Net asset (liability)	Earnings	AOCI	Net asset (liability)	Earnings	AOCI
Commodity price-risk hedging	$ (70.7)	$ (38.0)	$ (32.7)	$ (32.5)	$ (18.9)	$ (13.6)
Controlled trading program						
Interest rate risk hedging						
Currency exchange rate risk hedging	0.1	0.1		(2.0)	(2.0)	
	$ (70.6)	$ (37.9)	$ (32.7)	$ (34.5)	$ (20.9)	$ (13.6)

In addition to the $32.7 million of unrealized losses deferred to AOCI for open derivative positions, AOCI also includes a deferred loss of approximately $6.1 million that relates to terminated interest rate swaps that were cash settled in connection with the refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the terminated instruments.

The total amount of deferred net losses recorded in AOCI is 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 AOCI at March 31, 2007, a net loss of $32.4 million will be reclassified into earnings in the next twelve months; the remaining net loss will be reclassified at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2008 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 three months ended March 31, 2007 no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 10 Related Party Transactions

Crude Oil Purchases and Hedges. Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. (Calumet). Calumet is now owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. We purchased crude oil from Calumet for approximately $11.3 million and $11.3 million in the first quarter of 2007 and 2006, respectively. Calumet may request from time to time that we provide fixed pricing or a range of pricing for a portion of its production. When we offer such an arrangement, we protect our position by placing hedges on equivalent amounts, and charge Calumet a fee of $0.20 per barrel.

Gas Hedges. PAA/Vulcan is developing a natural gas storage facility through its wholly owned subsidiary, Pine Prairie Energy Center, LLC (Pine Prairie). Proper functioning of the Pine Prairie storage caverns will require a minimum operating inventory contained in the caverns at all times (referred to as base gas). During the first quarter of 2006, we arranged to provide the base gas for the storage facility to Pine Prairie at a price not to exceed $8.50 per million cubic feet. In conjunction with this arrangement, we executed hedges on the NYMEX for the relevant delivery periods of 2008, 2009 and 2010. We recorded deferred revenue for receipt of a one-time fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

Note 11 Income Taxes

Our U.S. and Canadian subsidiaries are not taxable entities in the U.S. and are not subject to U.S. federal or state income taxes as the tax effect of operations is passed through to our unitholders. However, certain of our Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes.

We adopted the provisions of FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN 48), an interpretation of SFAS No. 109 on January 1, 2007. As a result of the implementation of FIN 48, we recognized no material adjustment in the liability for unrecognized income tax benefits and at March 31, 2007, we have no material adjustments for unrecognized tax benefits.

We recognize interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 2007, we have no material adjustments for accrued interest related to uncertain tax positions.

We file income tax returns in the Canadian federal and various provincial jurisdictions. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years before 2004.

Note 12 Commitments and Contingencies

Litigation

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. 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 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 both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the U.S. Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was 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 $3.0 million to $3.5 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the DOJ) for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. We are cooperating in the investigation. Our assessment is that it is probable we will pay penalties related to the two releases. We have accrued the estimated loss contingency, which is included in the estimated aggregate costs set forth above. It is reasonably possible that the loss contingency may exceed our estimate with respect to penalties assessed by the DOJ; however, we have no indication from EPA or the DOJ of what penalties might be sought. As a result, we are unable to estimate the range of a reasonably possible loss contingency in excess of our accrual.

On November 15, 2006, we completed the acquisition of Pacific. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which had been incurred as of March 31, 2007. We expect to incur the remaining costs before the end of 2007. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy.

In March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine, if any, that can be assessed is estimated to be approximately $1,100,000 in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of the natural resource damages amount. We believe that certain of the alleged violations are without merit and intend to defend against them, and that mitigating factors should apply.

The EPA has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $3.7 million. We believe that several mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be assessed by the EPA cannot be ascertained. Discussions with the DOJ to resolve this matter have commenced.

Kosseff v. Pacific Energy, et al, case no. BC 3544016. On June 15, 2006, a lawsuit was filed in the Superior Court of California, County of Los Angeles, in which the plaintiff alleged that he was a unitholder of Pacific and he sought to represent a class comprising all of Pacific s unitholders. The complaint named as defendants Pacific and certain of the officers and directors of Pacific s general partner, and asserted claims of self-dealing and breach of fiduciary duty in connection with the pending merger with us and related transactions. The plaintiff sought injunctive relief against completing the merger or, if the merger was completed, rescission of the merger, other equitable relief, and recovery of the plaintiff s costs and attorneys fees. On September 14, 2006, Pacific and the other defendants entered into a memorandum of settlement with the plaintiff to settle the lawsuit. As part of the settlement, Pacific and the other defendants deny all allegations of wrongdoing and express willingness to settle the lawsuit solely because the settlement would eliminate the burden and expense of further litigation. The settlement is subject to customary conditions, including court approval. As part of the settlement, we (as successor to Pacific) will pay approximately $0.5 million to the plaintiff s counsel for their fees and expenses, and incur the cost of mailing materials to former Pacific unitholders. The court has preliminarily approved the settlement and a notice of settlement has been sent to the class members. If finally approved by the court, the settlement will resolve all claims that were or could have been brought on behalf of the proposed settlement class in the actions being settled, including all claims relating to the merger, the merger agreement and any disclosure made by Pacific in connection with the merger. The settlement did not change any of the terms or conditions of the merger.

Pacific Atlantic Terminals. In connection with the Pacific merger, we acquired Pacific Atlantic Terminals LLC (PAT), which is now one of our subsidiaries. PAT owns crude oil and refined products terminals in northern California and in the Philadelphia metropolitan area. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the California terminals that appeared to be out of compliance with specifications under the relevant air quality permit. We conducted a prompt review of the circumstances and self-reported the apparent historical occurrences of non-compliance to the Bay Area Air Quality Management District. We are cooperating with the District s review of these matters.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in the imposition of fines and penalties. For example, we have been informed by the EPA that terminals owned by Rocky Mountain Pipeline Systems LLC, one of the subsidiaries acquired in the Pacific merger, are purportedly out of compliance with certain regulatory documentation requirements.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from 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 typically improve on (decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the immediate post-acquisition period, however, the inclusion of additional miles of pipe in our operation may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link Energy LLC in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. See Pipeline Releases above.

At March 31, 2007, our reserve for environmental liabilities totaled approximately $36.6 million. At March 31, 2007, we have recorded receivables totaling approximately $9.7 million for amounts which are probable of recovery under insurance and from third parties under indemnification agreements. 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 considered 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. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

Table of Contents

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. 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 13 Operating Segments

In the fourth quarter of 2006, we revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. Prior period disclosures have been revised to reflect our change in segments. Our operations are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues and equity in earnings of unconsolidated entities less (i) purchases and related costs, (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. The following tables reflect certain financial data for each segment for the periods indicated:

	Transportation	Facilities	Marketing	Total
Three Months Ended March 31, 2007				
Revenues:				
External Customers	$ 102.0	$ 25.6	$ 4,101.9	$ 4,229.5
Intersegment (2)	76.2	19.5	7.7	103.4
Total revenues of reportable segments	$ 178.2	$ 45.1	$ 4,109.6	$ 4,332.9
Equity earnings in unconsolidated entities	$ 0.9	$ 2.7	$	$ 3.6
Segment profit (1)(3)(4)	$ 73.1	$ 21.9	$ 66.0	$ 161.0
SFAS 133 impact (1)	$	$	$ (17.0)	$ (17.0)
Maintenance capital	$ 3.2	$ 3.8	$ 3.7	$ 10.7

Three Months Ended March 31, 2006				
Revenues:				
External Customers (includes buy/sell revenues of $0, $0, and $4,761.9, respectively) (1)(5)	$ 71.7	$ 3.3	$ 8,560.1	$ 8,635.1
Intersegment (2)(5)	46.2	8.6	0.2	55.0
Total revenues of reportable segments	$ 117.9	$ 11.9	$ 8,560.3	$ 8,690.1
Equity earnings in unconsolidated entities	$ 0.3	$ (0.2)	$	$ 0.1
Segment profit (1)(3)(4)	$ 38.1	$ 2.5	$ 53.1	$ 93.7
SFAS 133 impact (1)	$	$	$ (0.7)	$ (0.7)
Maintenance capital	$ 3.0	$ 0.8	$ 0.9	$ 4.7

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

Table of Contents

(2) Intersegment sales are intended to reflect arms length transactions.

(3) Marketing segment profit includes interest expense on contango purchases of $11.2 million and $8.6 million for the three months ended March 31, 2007 and 2006, respectively.

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

	For the Three Months Ended March 31	
	2007	2006
Segment profit	$ 161.0	$ 93.7
Depreciation and amortization	(39.9)	(21.6)
Interest expense	(41.1)	(15.3)
Interest income and other, net	4.8	0.3
Income tax expense	(0.1)	
Income before cumulative effect of change in accounting principle	$ 84.7	$ 57.1

(5) The adoption of EITF 04-13 in 2006 resulted in inventory

purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations.

Note 14 Recent Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115 (SFAS 159). SFAS 159 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value in situations in which they are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. The provisions of SFAS 159 will be effective for fiscal years beginning after November 15, 2007. We are evaluating the impact of adoption of SFAS 159 but do not currently expect the adoption to have a material impact on our financial position, results of operations or cash flows.

In December 2006, the FASB issued FASB Staff Position EITF 00-19-2: Accounting for Registration Payment Arrangements (the FSP). The FSP specifies that the contingent obligation to make future payments under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5 Accounting for Contingencies . The FSP was effective immediately for registration payment arrangements and the financial instruments subject to those arrangements entered into or modified subsequent to December 21, 2006. For registration payment arrangements and for the financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the FSP is effective for fiscal years beginning after December 15, 2006. At March 31, 2007, we did not have any material contingent obligations under registration payment arrangements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The impact, if any, from the adoption of SFAS 157 in 2008 will depend on our assets and liabilities that are required to be measured at fair value at that time.

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. In addition, FIN 48 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized as an adjustment to the opening balance of retained earnings (or other appropriate components of equity) for that fiscal year. The provisions of FIN 48 were effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on our financial position, results of operations or cash flows. See Note 11.

In June 2006, the EITF issued Issue No. 06-3 (EITF 06-3), How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net presentation). EITF 06-3 is effective for all periods beginning after December 15, 2006 and its scope includes any tax that is assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF stated that it is an entity s accounting policy decision whether to present the taxes on a gross basis (within revenues and costs) or on a net basis (excluded from revenues) but that the accounting policy should be disclosed. If presented on a gross basis, an entity is required to report the amount of such taxes for each period for which an income statement is presented, if those amounts are significant. Our accounting policy is to present such taxes on a net basis.

Table of Contents

Note 15 Supplemental Condensed Consolidating Financial Information

In conjunction with the Pacific acquisition, some but not all of our 100% owned subsidiaries issued full, unconditional, and joint and several guarantees of our Senior Notes. Given that certain, but not all, subsidiaries are guarantors of our Senior Notes, we are required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, we are referred to as Plains All American , while the Guarantor Subsidiaries are PAA Finance Corp.; Plains Marketing, L.P.; Plains Pipeline, L.P.; Plains Marketing GP Inc.; Plains Marketing Canada LLC; Plains Marketing Canada, L.P.; PMC (Nova Scotia) Company; Basin Holdings GP LLC; Basin Pipeline Holdings, L.P.; Rancho Holdings GP LLC; Rancho Pipeline Holdings L.P.; Plains LPG Services GP LLC; Plains LPG Services, L.P.; Lone Star Trucking, LLC; Plains Marketing International GP LLC; Plains Marketing International, L.P.; Plains LPG Marketing, L.P.; Rocky Mountain Pipeline System, LLC; Pacific Marketing and Transportation LLC; Pacific Atlantic Terminals LLC; Pacific LA Marine Terminal, LLC; Ranch Pipeline LLC; PEG Canada GP LLC; PEG Canada, L.P.; Pacific Energy Group LLC; Pacific Energy Finance Corporation; Rangeland Pipeline Company; Rangeland Marketing Company; Rangeland Northern Pipeline Company; Rangeland Pipeline Partnership; and Aurora Pipeline Company, Ltd. and Non-Guarantor Subsidiaries are Atchafalaya Pipeline, L.L.C.; Andrews Partners, LLC; Pacific Pipeline System, LLC, Pacific Terminals, LLC, Pacific Energy Management LLC and Pacific Energy GP LP.

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting:

Condensed Consolidating Balance Sheet
March 31, 2007

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions) (unaudited)		
ASSETS					
Total current assets	$ 2,263.4	$ 2,798.2	$ 147.0	$ (2,399.1)	$ 2,809.5
Property plant and equipment, net		3,342.8	615.9		3,958.7
Other assets:					
Investment in unconsolidated entities	3,339.5	798.6		(3,942.4)	195.7
Other assets	22.0	1,220.4	306.7		1,549.1
Total assets	$ 5,624.9	$ 8,160.0	$ 1,069.6	$ (6,341.5)	$ 8,513.0
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 57.9	$ 4,871.0	$ 320.4	$ (2,398.7)	2,850.6
Other liabilities:					
Long-term debt	2,623.1	3.0			2,626.1
Other long-term liabilities	0.3	90.2	2.2		92.7
Total liabilities	2,681.3	4,964.2	322.6	(2,398.7)	5,569.4

Partners capital	2,943.6	3,195.8	747.0	(3,942.8)	2,943.6
Total liabilities and partners capital	$ 5,624.9	$ 8,160.0	$ 1,069.6	$ (6,341.5)	$ 8,513.0

Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2007

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions) (unaudited)		
Net operating revenues(1)	$	$ 301.8	$ 28.1	$	$ 329.9
Field operating costs		117.1	8.6		125.7
General and administrative expenses		48.0	(1.2)		46.8
Depreciation and amortization	0.7	34.2	5.0		39.9
Operating income	(0.7)	102.5	15.7		117.5
Equity earnings in unconsolidated entities	126.2	16.6		(139.2)	3.6
Interest expense	41.2	(0.1)			41.1
Interest and other income (expense)	0.4	4.4			4.8
Income tax expense		0.1			0.1
Net income (loss)	$ 84.7	$ 123.5	$ 15.7	$ (139.2)	$ 84.7

(1) Net operating revenues are calculated as Total revenues less Crude oil, refined products and LPG purchases and related costs.

Table of Contents

Condensed Consolidating Statements of Cash Flows
Three Months Ended March 31, 2007

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions) (unaudited)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 84.7	$ 123.5	$ 15.7	$ (139.2)	$ 84.7
Adjustments to reconcile to cash flows from operating activities:					
Depreciation, amortization and other	0.7	34.2	5.0		39.9
Inventory valuation adjustment		1.0			1.0
Gain on sale of investment assets		(3.9)			(3.9)
SFAS 133 mark-to-market adjustment		17.0			17.0
Long-Term Incentive Plan charge		18.6			18.6
Noncash amortization of terminated interest rate hedging instruments	0.2				0.2
Loss on foreign currency revaluation		(0.2)			(0.2)
Equity earnings in unconsolidated entities	(126.2)	(16.6)		139.2	(3.6)
Net change in assets and liabilities, net of acquisitions	155.4	82.3	(19.9)	0.2	218.0
Net cash provided by operating activities	114.8	255.9	0.8	0.2	371.7
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisition		(17.3)			(17.3)
Additions to property and equipment		(133.3)	(0.8)		(134.1)
Investment in unconsolidated entities, net	(9.1)	0.2		(0.2)	(9.1)
Cash paid for linefill in assets owned		(4.5)			(4.5)
Proceeds from sales of assets		4.3			4.3
	(9.1)	(150.6)	(0.8)	(0.2)	(160.7)

Net cash used in investing activities					
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on working capital revolving credit facility		(69.9)			(69.9)
Net repayments on short-term letter of credit and hedged inventory facility		(32.1)			(32.1)
Distributions paid to unitholders and general partner	(104.6)				(104.6)
Other financing activities		(0.2)			(0.2)
Net cash used in financing activities	(104.6)	(102.2)			(206.8)
Effect of translation adjustment on cash		1.1			1.1
Net increase in cash and cash equivalents	1.1	4.2			5.3
Cash and cash equivalents, beginning of period	2.3	9.0			11.3
Cash and cash equivalents, end of period	$ 3.4	$ 13.2	$	$	$ 16.6

For the three months ended March 31, 2006, the Non-Guarantor Subsidiaries were considered minor, as defined by Regulation S-X rule 3-10(h)(6) and thus, supplemental condensed consolidating financial information is not presented for that period.

Table of Contents

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.

Highlights First Quarter of 2007

Net income for the first quarter of 2007 was approximately $85 million, or $0.61 per diluted limited partner unit, which is an increase of 34% and a decrease of 14%, respectively, over net income of $63 million, or $0.71 per diluted limited partner unit for the first quarter of 2006.

Earnings per limited partner unit (both basic and diluted) was reduced by $0.04 for the three months ended March 31, 2006, attributable to the application of Emerging Issues Task Force (EITF) Issue No. 03-06, Participating Securities and the Two-Class Method under Financial Accounting Standards Board (FASB) Statement No. 128 . There was no impact of EITF 03-06 for the three months ended March 31, 2007. See Note 6 to our Consolidated Financial Statements.

Key items impacting the first three months of 2007 include:

Balance Sheet and Capital Structure

- The completion of two acquisitions for aggregate consideration of approximately $17 million.
- Capital expenditures for internal growth projects of $131 million for the first quarter of 2007, which represents approximately 26% of the 2007 planned expansion capital expenditures.

Income Statement

- Contributions from the November 2006 acquisition of Pacific Energy Partners L.P. (Pacific) as well as eight additional 2006 acquisitions.
- Increased volumes and related tariff revenues on our pipeline systems.

Table of Contents

Acquisitions and Internal Growth Projects

The following table summarizes our capital expenditures incurred in the periods indicated (in millions):

	Three Months Ended March 31,	
	2007	2006
Acquisition capital (1) (2)	$ 23.7	$
Internal growth projects	131.3	44.7
Maintenance capital	10.7	4.7
	$ 165.7	$ 49.4

(1) The amount for the first quarter of 2007 includes purchase price adjustments of approximately $7 million related to 2006 acquisitions.

(2) During the first quarter of 2006 we paid approximately $17 million into escrow for an acquisition that closed in April 2006.

Acquisitions

During the first quarter of 2007, we acquired (i) certain commercial refined products supply and marketing businesses (which are reflected in our marketing segment) for approximately $8 million in cash (including approximately $7 million of goodwill) and (ii) a trucking business (which is reflected in our transportation segment) for approximately $9 million in cash (including approximately $4 million of goodwill). Also, during the first quarter of 2007, we signed an agreement to acquire the Bumstead LPG storage facility located near Phoenix, Arizona for approximately $52 million. The acquisition is expected to close early in the second half of 2007 and will be reflected in our facilities segment.

Internal Growth Projects

Capital expenditures for expansion projects are forecast to be approximately $500 million during calendar 2007, of which approximately $131 million was incurred in the first three months. These projects include the construction and expansion of pipeline systems and crude oil and LPG storage facilities. Following are some of the more notable projects to be undertaken in 2007 and the estimated expenditures for the year (in millions):

Projects	2007
St. James, Louisiana Crude Oil Storage Facility	$ 75.0
Salt Lake City Pipeline Expansion	55.0

Patoka Crude Oil Tankage	40.0
Cheyenne Pipeline Expansion	39.0
Fort Laramie Tank Expansion	28.0
Martinez Terminal	27.0
Cushing Tankage - Phase VI	27.0
West Hynes Tanks	15.0
High Prairie Rail Terminal	12.0
Kerrobert Tankage	10.0
Pier 400	10.0
Paulsboro Expansion	8.0
Other Projects	154.0
Total	$500.0

We do not expect these projects to contribute significantly to net income or cash flow from operations in 2007, but expect them to have a more significant impact in 2008.

Results of Operations

Analysis of Operating Segments

See Note 13 to our Consolidated Financial Statements for a discussion on how we evaluate our segment performance and for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Table of Contents

Transportation

As of March 31, 2007, we owned active gathering and mainline crude oil and refined products pipelines located throughout the United States and Canada as well as active above-ground crude oil, refined products and LPG storage tanks, of which approximately half are utilized in our transportation segment. Our activities from transportation operations generally consist of (i) transporting crude oil and refined products for a fee; (ii) third-party leases of pipeline capacity (collectively referred to as tariff activities); (iii) the transportation of crude oil for third parties for a fee using our trucks; and (iv) barge transportation services provided by Settoon Towing (we own a 50% equity investment in Settoon Towing). Our transportation segment also includes our equity in earnings from our minority interests in the Butte and Frontier pipeline systems. In connection with certain of our merchant activities conducted under our marketing business, we are also shippers on a number 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 costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

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

	Three Months Ended March 31,	
	2007	**2006**
Operating Results [1] (in millions)		
Revenues		
Tariff revenue	$ 153.0	$ 95.5
Third-party trucking	25.2	22.4
Total transportation revenues	178.2	117.9
Costs and Expenses		
Third-party trucking costs	(17.5)	(18.2)
Field operating costs (excluding LTIP charge)	(66.4)	(46.9)
LTIP charge operations [2]	(2.1)	(1.1)
Segment G&A expenses (excluding LTIP charge) [3]	(12.6)	(9.9)
LTIP charge general and administrative [2]	(7.4)	(4.0)
Equity earnings in unconsolidated entities	0.9	0.3
Segment profit	$ 73.1	$ 38.1
Maintenance capital	$ 3.2	$ 3.0
Segment profit per barrel	$ 0.31	$ 0.23
Average Daily Volumes (thousands of barrels per day)[4]		
Tariff activities:		
All American	50	44
Basin	342	314
BOA/CAM	181	N/A

Capline	235	86
Line 63 / 2000	181	N/A
Salt Lake City	61	N/A
North Dakota/Trenton	95	82
West Texas/New Mexico area systems	368	399
Manito	74	66
Other	908	823
	2,495	1,814
Refined Products	115	N/A
Total tariff activities	2,610	1,814

(1) Revenues and purchases include intersegment amounts.

(2) Compensation expense related to our LTIP.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(4) 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.

Table of Contents

Segment profit, our primary measure of segment performance, was impacted in the first quarter of 2007 compared to the first quarter of 2006 by the following:

Increased volumes and related tariff revenues The increase in tariff revenues resulted from (i) higher volumes primarily from multi-year contracts on our Basin and Capline systems entered into during the second quarter of 2006, (ii) increased volumes associated with the acquisition of systems in the second, third and fourth quarters of 2006, (iii) higher volumes on various other systems, (iv) an annual tariff escalation, and (v) increased revenues from 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 subsequent sales of allowance oil barrels are also included in tariff revenues. Increased volumes during the first quarter of 2007 as compared to the first quarter of 2006 have resulted in increased revenues related to loss allowance oil.

Increased field operating costs Field operating costs have increased for most categories of costs for the first quarter of 2007 compared to the first quarter of 2006 as we have continued to grow through acquisitions and expansion projects. The most significant cost increases in the first quarter of 2007 have been related to (i) payroll and benefits, (ii) utilities, (iii) pipeline integrity work, and (iv) property taxes. Payroll and benefits increased approximately $7 million primarily due to the 2006 acquisitions.

Increased segment G&A expenses Segment G&A expenses excluding LTIP charges increased in the first quarter of 2007 compared to the first quarter of 2006 primarily due to payroll and benefits relating to our growth through acquisitions.

Increased LTIP expenses LTIP charges included in field operating costs and segment G&A expenses increased approximately $4 million in the first quarter of 2007 over the first quarter of 2006, primarily as a result of additional units issued and an increase in our unit price to $57.61 at March 31, 2007 from $51.20 at December 31, 2006. The first quarter of 2007 includes a catch-up expense associated with the increase in the price of the units. See Note 8 to our Consolidated Financial Statements.

In the first quarter of 2007, average daily volumes from our tariff activities increased by approximately 800,000 barrels per day or 44% and tariff revenues increased by approximately $58 million or 60%. The increase in volumes and tariff revenues is attributable to a combination of the following factors:

Pipeline systems acquired or brought into service during the last nine months of 2006, which contributed approximately 714,000 barrels per day and $45 million of revenues during the first quarter of 2007;

Facilities

As of March 31, 2007, we owned active above-ground crude oil, refined products and LPG storage tanks, of which approximately half are included in our facilities segment. The remaining tanks are utilized in our transportation segment. At March 31, 2007, we were in the process of constructing additional above ground terminalling and storage facilities, which we expect to place in service during the remainder of 2007 and during 2008.

Table of Contents

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. On a stand-alone basis, segment profit from facilities activities is dependent on the storage capacity leased, volume of throughput and the level of fees for such services.

We generate fees through a combination of month-to-month and multi-year leases and processing arrangements with third parties and with our marketing segment. Fees generated in this segment include (i) storage fees that are generated when we lease tank capacity and (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil or refined products from one connecting pipeline and redeliver crude oil or refined products to another connecting carrier.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan).

Total revenues for our facilities segment in 2007 have increased compared to 2006. The revenue increase is driven primarily by increased volumes resulting from our acquisition activities and, to a lesser extent, tankage construction projects completed in 2006 and 2007.

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

	Three Months Ended March 31,	
	2007	**2006**
Operating Results (in millions)		
Storage and Terminalling Revenues (1)	$ 45.1	$ 11.9
Field Operating costs (excluding LTIP charge)	(18.9)	(5.5)
LTIP charge operations (3)		
Segment G&A expenses (excluding LTIP charge) (2)	(4.9)	(2.5)
LTIP charge general and administrative (3)	(2.1)	(1.2)
Equity earnings in unconsolidated entities	2.7	(0.2)
Segment profit	$ 21.9	$ 2.5
Maintenance capital	$ 3.8	$ 0.8
Segment profit per barrel	$ 0.19	$ 0.05
Volumes (4)		
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	35.2	16.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	11.5
LPG processing (thousands of barrels per day)	13.7	N/A
Facilities activities total (average monthly capacity in millions of barrels) (5)	37.8	18.7

(1) Revenues include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our LTIP.

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

(5) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG and crude processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly volumes in millions.

Table of Contents

Segment profit (our primary measure of segment performance) and revenues were impacted in the first quarter of 2007 by the following:

- Increased storage and terminalling revenues from crude facilities The increase in volumes and related revenues during the first quarter of 2007 primarily relates to (i) the acquisition of Pacific in the fourth quarter of 2006 and other acquisitions completed during 2006, (ii) the utilization of capacity at the Mobile facility that was acquired from Link in 2004 but not used extensively until the last nine months of 2006, and (iii) additional capacity resulting from the St. James construction project, which was placed in early stage operation in early 2007;

- Increased storage and terminalling revenues from LPG facilities The increase in volumes and related revenues during the first quarter of 2007 primarily relates to expansions completed during 2006;

- Revenues from refined product storage and terminalling We had no revenue from refined products storage and terminalling until the acquisition of Pacific, which contributed additional revenues of approximately $10 million in the first quarter of 2007; and

- Increased revenues from LPG processing The acquisition of the Shafter processing facility during the second quarter of 2006 resulted in additional processing revenues of approximately $8 million for the first quarter of 2007.

Segment profit was also impacted in the first quarter of 2007 by the following:

- Increased field operating costs Our continued growth, primarily from the acquisitions completed during 2007 and 2006 and the additional tankage added in 2007 and 2006, is the principal cause of the increase in field operating costs in the first quarter of 2007. Of the total increase, $4 million relates to the operating costs associated with the Shafter processing facility, which we acquired in the second quarter of 2006 and $7 million relates to the operating costs associated with the Pacific acquisition. The remainder of the increase in operating costs primarily relate to (i) payroll and benefits, (ii) maintenance and (iii) utilities;

- Increased segment G&A expenses Segment G&A expenses excluding LTIP charges increased in the first quarter of 2007 compared to the same period in 2006, primarily as a result of an increase in payroll and benefits in the first quarter of 2007 as the operations have grown since the first quarter of 2006;

- Increased LTIP expenses LTIP charges included in field operating costs and segment G&A expenses increased approximately $1 million in the first quarter of 2007 over the first quarter of 2006, primarily as a result of additional units issued and an increase in our unit price to $57.61 at March 31, 2007 from $51.20 at December 31, 2006. The first quarter of 2007 includes a catch-up expense associated with the increase in the price of the units. See Note 8 to our Consolidated Financial Statements; and

- Increased equity earnings in unconsolidated entities Our investment in PAA/Vulcan contributed approximately $3 million in additional earnings, reflecting increased value for storage leased.

Marketing

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the marketing of natural gas liquids, 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. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our marketing segment volumes (which consist of (i) lease gathered crude oil volumes, (ii) refined products volumes,

(iii) LPG sales volumes, and (iv) waterborne foreign crude imported volumes), as well as the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can

Table of Contents

provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and will vary from period to period.

In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) marketing segment volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our marketing segment for the comparable periods indicated:

	Three Months Ended March 31,	
	2007	**2006**
Operating Results[1] **(in millions)**		
Revenues [2] [3]	$ 4,109.6	$ 8,560.3
Purchases and related costs [4] [5]	(3,985.5)	(8,461.3)
Field operating costs (excluding LTIP charge)	(38.2)	(31.6)
LTIP charge operations[6]	(0.1)	(0.1)
Segment G&A expenses (excluding LTIP charge) [7]	(12.9)	(10.0)
LTIP charge general and administrative[6]	(6.9)	(4.2)
Segment profit [3]	$ 66.0	$ 53.1
SFAS 133 mark-to-market adjustment [3]	$ (17.0)	$ (0.7)
Maintenance capital	$ 3.7	$ 0.9
Segment profit per barrel [8]	$ 0.83	$ 0.79
Average Daily Volumes (thousands of barrels per day) [9]		
Crude oil lease gathering	680	615
Refined Products	3	N/A
LPG sales	133	84
Waterborne foreign crude imported	67	48
Marketing activities total	883	747

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

(2) Includes revenues associated with buy/sell arrangements of $0 and

$4,761.9 million for the three months ended March 31, 2007 and 2006, respectively. Volumes associated with these arrangements were approximately 919,500 barrels per day for the three months ended March 31, 2006. 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) Includes purchases associated with buy/sell arrangements of $0 and $4,795.1 million for the three months ended March 31, 2007 and 2006, respectively. Volumes associated with these

arrangements were approximately 926,800 barrels per day for the three months ended March 31, 2006. 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.

(5) Purchases and related costs include interest expense on contango inventory purchases of $11.2 million and $8.6 million for the three months ended March 31, 2007 and 2006, respectively.

(6) Compensation expense related to our LTIP.

(7) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business

activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(8) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes, and waterborne foreign crude volumes.

(9) 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.

Table of Contents

Our first quarter 2007 revenues decreased compared to the first quarter of 2006 due to the adoption in the second quarter of 2006 of EITF Issue No. 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). According to EITF 04-13, inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The adoption of EITF 04-13 in the second quarter of 2006 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases on our income statement but does not impact our financial position, net income, or liquidity.

The primary factors affecting revenues and segment profit were:

Acquisitions During the last nine months of 2006 we purchased certain crude oil gathering assets and related contracts in South Louisiana, and completed the acquisitions of Pacific and Andrews Petroleum and Lone Star Trucking (Andrews).

Favorable market conditions and execution of our risk management strategies During the first quarter of 2007 and the first quarter of 2006, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from $49.90 to $68.09 during the first quarter of 2007. The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The volatile market also led to favorable basis differentials for various delivery points and grades of crude oil. The market was in contango for the first quarter of 2007 and the monthly time spread of prices averaged approximately $1.21 versus $1.14 for the first quarter of 2006; this increase in spreads was partially offset by an increase in the per barrel cost to carry the inventory that was impacted by the increase in LIBOR rates. Marketing segment profit is net of contango and other hedged inventory related interest expense (which is incurred to store the crude oil) of approximately $11.2 million for the first quarter of 2007 (compared to $8.6 million in the first quarter of 2006). This cost is included in Purchases and related costs in the table above.

SFAS 133 mark-to-market The first quarter of 2007 includes SFAS 133 mark-to-market losses of $17.0 million compared to a loss of $0.7 million for the first quarter of 2006. See Note 9 to our Consolidated Financial Statements.

Field operating costs and segment G&A expenses Field operating costs (excluding LTIP charges) increased in the first quarter of 2007 compared to the first quarter of 2006, primarily as a result of increases in payroll and benefits and contract transportation as a result of 2006 acquisitions and changes in driver incentive programs. The increase in general and administrative expenses (excluding LTIP charges) is primarily the result of an increase in the payroll and benefits, and indirect costs allocated to the marketing segment in the first quarter of 2007 as the operations have grown.

Increased LTIP expenses LTIP charges included in field operating costs and segment G&A expenses increased approximately $3 million in the first quarter of 2007 over the first quarter of 2006, primarily as a result of additional phantom units issued and an increase in our unit price to $57.61 at March 31, 2007 from $51.20 at December 31, 2006. The first quarter of 2007 includes a catch-up expense associated with the increase in the price of the units. See Note 8 to our Consolidated Financial Statements.

Segment profit per barrel (calculated based on our marketing volumes included in the table above) was $0.83 for the first quarter of 2007, compared to $0.79 for the first quarter of 2006. As discussed above, our current period results were impacted by (i) SFAS 133 mark-to-market losses of $17 million, the majority of which relates to inventory hedges and will be offset by gains in future periods when the physical inventory is sold, (ii) favorable market conditions and (iii) a change in the business mix to include the Pacific and

Andrews acquisitions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as we have recently experienced, and these operating results may not be indicative of sustainable performance.

Other Expenses

Depreciation and Amortization

Depreciation and amortization expense increased $18.3 million for the first quarter of 2007 compared to the comparable 2006 period primarily as a result of a continued expansion in our asset base from acquisitions and internal growth projects. Amortization of debt issue costs totaled approximately $1 million for the first three months of 2007 and was relatively constant compared to the same period in 2006.

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; and
- market interest rates and our interest rate hedging activities on floating rate debt.

Interest expense increased approximately 169% in the first quarter of 2007, as compared to the first of 2006, primarily due to higher average debt balances during 2007 partially offset by increased capitalized interest associated with certain capital projects under construction. The higher average debt balance in the first three months of 2007 was primarily related to the addition or assumption of $1.7 billion of senior notes in the last nine months of 2006 to finance acquisitions. Our financial growth strategy is to fund our acquisitions and expansion capital expenditures using approximately 50% debt, with the balance funded through retained cash flow and equity issuances.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing 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 $11.2 million and $8.6 million for the first quarter of 2007 and the first quarter of 2006, respectively.

Outlook

This section identifies 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 regarding potential acquisitions by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets that, if acquired, could 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 midstream businesses outside of the scope of our current operations, but with respect to which these resources effectively can be applied. For example, during the first quarter of 2007, we entered the refined products marketing business and during 2006 we entered the refined products transportation and storage business as well as the barge transportation business. 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.

Pipeline Integrity and Storage Tank Testing Compliance. Although we believe our previously disclosed short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar regulations in Canada) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire additional assets. In our annual report on Form 10-K for the year ended December 31, 2006, we reported that the DOT will be issuing by December 31, 2007, new regulations governing hazardous liquid pipelines operated at low stress. We do not currently know what, if any, impact these developments will have on our operating expenses and, thus, cannot provide any assurances that future costs related to these programs will not be material.

Longer-Term Outlook. In our annual report on Form 10-K for the year ended December 31, 2006, we identified certain trends, factors and developments, many of which are beyond our control, that may affect our business in the future. We believe the collective impact of these trends, factors and developments will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident in 2005 and 2006. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

We are also regularly evaluating midstream businesses that are complementary to our existing businesses and that possess attractive long-term growth prospects. Through PAA/Vulcan s acquisition of ECI in 2005, the Partnership entered the natural gas storage business. During 2006, we entered the refined products transportation and storage business. We intend to grow both of these areas of our business through future acquisitions and expansion projects. We also intend to apply our business model to the refined products business by expanding a recently acquired marketing and distribution business to complement our strategically located assets.

Liquidity and Capital Resources

Liquidity

Cash flow from operations and our credit facilities are our primary sources of liquidity. At March 31, 2007, we had a working capital deficit of approximately $41 million, approximately $1.4 billion of availability under our committed revolving credit facilities and approximately $0.4 billion of availability under our uncommitted hedged inventory facility. Our working capital decreased approximately $174 million in the first quarter of 2007. See *Cash flow from operations*, below, for discussion of the relationship between working capital items and our short-term borrowings. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash flow from operations

The crude oil market was in contango for the first quarter of 2007 and for much of 2006. Because we own crude oil storage capacity, during a contango market we can buy crude oil in the current month and simultaneously hedge the crude by selling it forward for delivery in a subsequent month. This activity can cause significant fluctuations in our cash flow from operating activities as described below.

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products 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 (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines. The storage of crude oil in periods of a contango market can have a material negative impact on our cash flows from operating activities for the period in which we pay for and store the crude oil and a material positive impact in the subsequent period in which we receive proceeds from the sale of the crude oil. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it. Our accounts payable and accounts receivable generally vary proportionately because we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. However, when the market is in contango, our accounts receivable, accounts payable, inventory and short-term debt balances are all impacted, depending on the point of the cycle at any particular period end. As a result, we can have significant fluctuations in those working capital accounts, as we buy, store and sell crude oil.

Our cash flow provided by operating activities in the first quarter of 2007 was $371.7 million compared to cash used in operating activities of $457.6 million in the first quarter of 2006. This change reflects cash generated by our recurring operations in addition to a decrease in certain working capital items of approximately $218.0 million. In the first quarter of 2007, although the market was in contango, due to the sale of some of our LPG inventory (resulting from customers heating requirements in the winter months), and due to the timing of receipts and deliveries of crude oil, we decreased our storage of crude oil and LPG and made repayments under our credit facilities, resulting in a positive impact on our cash flows from operating activities for the period, as explained above.

Table of Contents

Cash provided by equity and debt financing activities

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2 billion of debt or equity securities. At March 31, 2007, we have approximately $1.1 billion of unissued securities remaining available under this registration statement.

Cash used in financing activities was $206.8 million for the three months ended March 31, 2007 and cash provided by financing activities was $541.5 million for the three months ended March 31, 2006. During the three months ended March 31, 2007 we had net repayments of our working capital and hedged inventory borrowings of approximately $102.0 million and during the three months ended March 31, 2006, we had net working capital borrowings and hedged inventory borrowings of approximately $498.3 million, respectively. Our financing activities primarily relate to (i) funding acquisitions and internal capital projects and (ii) funding and repayments under our short-term working capital and hedged inventory facilities related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities. During the first quarter of 2007, we made repayments under our credit facilities as a result of the decrease in the storage of crude oil and LPG and also borrowed under our credit facilities to fund capital expenditures.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

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 and the financing activities discussed above. Our primary uses of cash are for our acquisition activities, capital expenditures for internal growth projects and distributions paid to our unitholders and general partner. See Acquisitions and Internal Growth Projects. The price of the acquisitions includes cash paid, transaction costs and assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total value of the acquisitions completed during the year.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Total cash distributions made during the first quarter of 2007 and the first quarter of 2006 were as follows (in millions, except per unit amounts):

	Distributions Paid				
	Common	GP			Distribution
	Units	Incentive	2%	Total	per unit
1st Quarter 2007	$ 87.5	$ 15.3	$ 1.8	$ 104.6	$ 0.8000
1st Quarter 2006	$ 50.7	$ 5.6	$ 1.0	$ 57.3	$ 0.6875

On April 17, 2007, we declared a cash distribution of $0.8125 per unit on our outstanding common units. The distribution is payable on May 15, 2007, to unitholders of record on May 4, 2007, for the period January 1, 2007 through March 31, 2007. The total distribution to be paid is approximately $107.4 million, with approximately $88.9 million to be paid to our common unitholders and approximately $1.8 million and $16.7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

Contingencies

See Note 12 to our Consolidated Financial Statements.

Table of Contents

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil, LPG and refined products 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 purchases and sales and future delivery obligations. At March 31, 2007 and December 31, 2006, these obligations amounted to $6.4 billion and $4.6 billion, respectively. Other contractual obligations did not vary significantly since December 31, 2006. Where applicable, the amounts presented in the table below 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 hedged inventory borrowings and by corresponding sales to creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments due under the specified contractual obligations as of March 31, 2007.

	Total	2007	2008	2009	2010	2011	2012 and Thereafter
				(In millions)			
Crude oil and LPG purchases(1)	$ 6,384.7	$ 3,608.8	$ 931.8	$ 643.6	$ 470.1	$ 383.0	$ 347.4

(1) 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 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 periods of up to 70 days and are terminated upon completion of each transaction. At March 31, 2007, we had outstanding letters of credit of approximately $120.0 million.

Capital Contributions to PAA/Vulcan Gas Storage, LLC. We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage s obligation is subject to a maximum amount, beyond which Vulcan Gas Storage s participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas Storage s participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage s interest. Once PAA s ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future capital contributions proportionate to its ownership interest at the time. During the first quarter of 2007, we made an additional contribution of approximately $9 million to PAA/Vulcan. Such contribution did not result in an increase to our ownership interest. See Note 10 to our Consolidated Financial Statements.

Distributions. We plan to distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of the quarter, less reserves established in the discretion of our general partner for future requirements. On April 17, 2007, we declared a cash distribution of $0.8125 per unit on our outstanding common units. The distribution is payable on May 15, 2007, to unitholders of record on May 4, 2007, for the period January 1, 2007 through March 31, 2007. The total distribution to be paid is approximately $107.4 million, with approximately $88.9 million to be paid to our common unitholders and approximately $1.8 million and $16.7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively. On February 14, 2007, we paid a cash distribution of $0.80 per unit on all outstanding units. The total distribution paid was approximately $104.6 million, with approximately $87.5 million paid to our common unitholders and approximately $17.1 million paid to our general partner for its general partner interest ($1.8 million) and incentive distribution interest ($15.3 million).

Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts of its incentive distributions as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. Pursuant to this agreement, the first quarterly reduction of $5 million occurred with the incentive distribution paid to the general partner on February 14, 2007. The incentive distribution to be paid in May 2007 also reflects a reduction of $5 million. The total reduction in incentive distributions will be $65 million.

Recent Accounting Pronouncements and Change in Accounting Principle

See Note 14 to our Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see Item 7 of our 2006 Annual Report on Form 10-K.

Forward-Looking Statements and Associated Risks

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements identified by the words anticipate, believe, estimate, expect, plan, inten forecast, and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. 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:

- the failure to realize the anticipated synergies and other benefits of the merger with Pacific;
- the success of our risk management activities;
- 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;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
- failure to implement or capitalize on planned internal growth projects;
- shortages or cost increases of power supplies, materials or labor;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third party shippers;
- fluctuations in refinery capacity in areas supplied by our mainlines, and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements;

Table of Contents

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 and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

unanticipated changes in crude oil market structure and volatility (or lack thereof);

the impact of current and future laws, rulings and governmental regulations;

the effects of competition;

continued creditworthiness of, and performance by, our counterparties;

interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

increased costs or lack of availability of insurance;

fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plans;

the currency exchange rate of the Canadian dollar;

weather interference with business operations or project construction;

risks related to the development and operation of natural gas storage facilities;

general economic, market or business conditions; and

other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors, such as the Risks Related to Our Business discussed in Item 1A. Risk Factors of our most recent annual report on Form 10-K and 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 RISK

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risks included in Item 7A in our 2006 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 9 to our Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

All of our open commodity price risk derivatives at March 31, 2007 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 increase are shown in the table below:

Effect of 10%

	Fair Value	Price Increase
	(In millions)	
Crude oil:		
Futures contracts	$ (35.6)	$ (33.3)
Swaps and options contracts	$ (46.7)	$ (19.4)
LPG and other:		
Futures contracts	$ 0.3	$ 6.4
Swaps and options contracts	$ 11.3	$ 1.4
Total Fair Value	$ (70.7)	

Table of Contents

Interest Rate Risk

We use 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 use interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. In addition, in connection with the Pacific merger in the fourth quarter of 2006, we assumed interest rate swaps with an aggregate notional amount of $80 million. The interest rate swaps are a hedge against changes in the fair value of the 7.125% Senior Notes resulting from market fluctuations to LIBOR. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at March 31, 2007. All of our senior notes are fixed rate notes and thus 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 March 31, 2007. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

	Expected Year of Maturity						
	2007	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**
	(Dollars in millions)						
Liabilities:							
Short-term debt variable rate	$ 893.4	$	$	$	$	$	$ 893.4
Average interest rate	5.8%						5.8%

Item 4. CONTROLS AND PROCEDURES

We maintain written disclosure controls and procedures, which we refer to as our DCP. The purpose of our DCP is to provide reasonable assurance that information is (i) recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) 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 March 31, 2007, 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.

SEC rules also require an annual evaluation of the effectiveness of our internal control over financial reporting (internal control), and a quarterly evaluation of any changes in our internal control. In the course of such evaluations, we have made changes, and will continue to make changes, to refine and improve our internal control. We are required to disclose any change in our internal control that occurred during the quarter that has materially affected, or is reasonably likely to materially affect, our internal control. As a result of their evaluation of changes in internal control, management identified no changes during the first quarter of 2007 that materially affected, or would be reasonably likely to materially affect, 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.

Table of Contents

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See Note 12 to our Consolidated Financial Statements.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2006 Annual Report on Form 10-K. These risks and uncertainties are not the only ones facing us and there may be additional matters that we are unaware of or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.4	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.5	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.6	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.7	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005).
3.8	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005).
3.9	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.10	Certificate of Incorporation of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to

	Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).

4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
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4.13	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1 / 8 % senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

4.14	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 $^1/8$% senior notes due 2014 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed March 9, 2005).
4.15	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 $^1/8$% senior notes due 2014 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.16	Third Supplemental Indenture dated November 15, 2006 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Plains Marketing International GP LLC, Plains Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).
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Trucking, LLC, Plains Marketing International GP LLC, Plains LPG Marketing, L.P., Plains Marketing International, L.P., Citigroup Global Markets Inc., UBS Securities LLC, Banc of America Securities LLC, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, BNP Paribas Securities Corp., SunTrust Capital Markets, Inc., Fortis Securities LLC, Scotia Capital (USA) Inc., Comerica Securities, Inc., Commerzbank Capital Markets Corp., Daiwa Securities America Inc., DnB NOR Markets, Inc., HSBC Securities (USA) Inc., ING Financial Markets LLC, Mitsubishi UFJ Securities International plc, Piper Jaffray & Co., RBC Capital Markets Corporation, SG Americas Securities, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC relating to the 2017 Notes (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed October 30, 2006).

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**10.1	Final Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers).
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 Principal Executive Officer pursuant to 18 U.S.C. 1350.
*32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.

Filed herewith.

* Furnished herewith.

** Management compensatory plan or arrangement.

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 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: May 9, 2007

By: /s/ GREG L. ARMSTRONG

Greg L. Armstrong, *Chairman of the Board,*
Chief Executive Officer and Director
(Principal Executive Officer)

Date: May 9, 2007 By: /s/ PHIL KRAMER

Phil Kramer, *Executive Vice President and*
Chief Financial Officer (Principal Financial Officer)

Index to Exhibits

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.4	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.5	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.6	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.7	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005).
3.8	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005).
3.9	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.10	Certificate of Incorporation of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary

	Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).

4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
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4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
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45

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47