PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 08, 2008
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2008

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

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

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

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

At August 5, 2008, there were outstanding 122,911,645 Common Units.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	June 30, 2008	December 31, 2007
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 11	$ 24
Trade accounts receivable and other receivables, net	3,036	2,561
Inventory	1,181	972
Other current assets	368	116
Total current assets	4,596	3,673
PROPERTY AND EQUIPMENT	5,619	4,938
Accumulated depreciation	(603)	(519)
	5,016	4,419
OTHER ASSETS		
Pipeline linefill in owned assets	426	284
Inventory in third-party assets	80	74
Investment in unconsolidated entities	251	215
Goodwill	1,260	1,072
Other, net	260	169
Total assets	$ 11,889	$ 9,906
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,724	$ 2,577
Short-term debt	719	960
Other current liabilities	305	192
Total current liabilities	4,748	3,729
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	1	1
Senior notes, net of unamortized net discount of $6 and $2, respectively	3,219	2,623
Other long-term liabilities and deferred credits	334	129
Total long-term liabilities	3,554	2,753
COMMITMENTS AND CONTINGENCIES (NOTE 12)		

PARTNERS CAPITAL				
Common unitholders (122,911,645 and 115,981,676 units outstanding as of June 30, 2008 and December 31, 2007, respectively)		3,503		3,343
General partner		84		81
Total partners capital		3,587		3,424
Total liabilities and partners capital	$	11,889	$	9,906

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(unaudited)		(unaudited)	
REVENUES	$ 9,060	$ 3,918	$ 16,255	$ 8,148
COSTS AND EXPENSES				
Crude oil, refined products and LPG purchases and related costs	8,724	3,529	15,560	7,429
Field operating costs	152	136	297	261
General and administrative expenses	51	48	90	95
Depreciation and amortization	52	52	100	92
Total costs and expenses	8,979	3,765	16,047	7,877
OPERATING INCOME	81	153	208	271
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	5	7	8
Interest expense (net of capitalized interest of $3, $3, $9 and $6, respectively)	(49)	(41)	(91)	(82)
Interest income and other income (expense), net	10		12	5
Income before tax	46	117	136	202
Current income tax expense	(5)	(1)	(6)	(1)
Deferred income tax benefit (expense)		(11)	3	(11)
NET INCOME	$ 41	$ 105	$ 133	$ 190
NET INCOME-LIMITED PARTNERS	$ 16	$ 86	$ 83	$ 154
NET INCOME-GENERAL PARTNER	$ 25	$ 19	$ 50	$ 36
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.13	$ 0.78	$ 0.70	$ 1.40
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.13	$ 0.78	$ 0.69	$ 1.39
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	120	110	118	110
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	121	111	119	111

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six Months Ended June 30, 2008	2007
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 133	$ 190
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	100	92
SFAS 133 mark-to-market adjustment	92	2
Equity compensation expense	24	40
Deferred income tax (benefit) expense	(3)	11
Gain on foreign currency revaluation	(10)	(2)
Equity earnings in unconsolidated entities, net of distributions	5	(8)
Other	(5)	(2)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(651)	36
Inventory	(234)	(235)
Accounts payable and other current liabilities	1,127	147
Due to related parties	(2)	2
Net cash provided by operating activities	576	273
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 4)	(661)	(18)
Additions to property and equipment	(301)	(267)
Investment in unconsolidated entities	(40)	(9)
Cash paid for linefill in assets owned		(15)
Proceeds from sales of assets	15	13
Net cash used in investing activities	(987)	(296)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on revolving credit facility	(204)	(175)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	(56)	52
Proceeds from the issuance of senior notes (Note 6)	597	
Net proceeds from the issuance of common units (Note 8)	315	383
Distributions paid to common unitholders (Note 8)	(199)	(176)
Distributions paid to general partner (Note 8)	(52)	(36)
Other financing activities	(5)	
Net cash provided by financing activities	396	48
Effect of translation adjustment on cash	2	9
Net increase (decrease) in cash and cash equivalents	(13)	34
Cash and cash equivalents, beginning of period	24	11
Cash and cash equivalents, end of period	$ 11	$ 45
Cash paid for interest, net of amounts capitalized	$ 92	$ 75
Cash paid for income taxes	$ 4	$ 2

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units Units		Common Units Amount		General Partner Amount		Partners Capital Amount
			(unaudited)				
Balance at December 31, 2007	**116**	**$**	**3,343**	**$**	**81**	**$**	**3,424**
Net income			83		50		133
Issuance of common units	7		309		6		315
Issuance of common units under Long Term Incentive Plans (LTIP)			1				1
Distributions			(199)		(52)		(251)
Class B Units of Plains AAP, L.P.			10				10
Other comprehensive loss			(44)		(1)		(45)
Balance at June 30, 2008	**123**	**$**	**3,503**	**$**	**84**	**$**	**3,587**

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30, 2008		Three Months Ended June 30, 2007		Six Months Ended June 30, 2008		Six Months Ended June 30, 2007
	(unaudited)				(unaudited)		
Net income	$	41	$	105	$	133	$	190

Net income	$	41	$	105	$	133	$	190
Other comprehensive income/(loss)		20		58		(45)		45
Comprehensive income	$	61	$	163	$	88	$	235

CONDENSED 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, 2007	$ 4	$ 176	$ 180
Reclassification adjustments for settled contracts	8		8
Changes in fair value of outstanding hedge positions	(15)		(15)
Currency translation adjustment		(38)	(38)
Total period activity	(7)	(38)	(45)
Balance at June 30, 2008	$ (3)	$ 138	$ 135

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

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. a subsidiaries, unless the context indicates otherwise. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC.

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2007 Annual Report on Form 10-K. 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. The results of operations for the three months and six months ended June 30, 2008 should not be taken as indicative of the results to be expected for the full year.

Note 2 Recent Accounting Pronouncements

In June 2008, the Emerging Issues Task Force (EITF) issued Issue No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (EITF 03-6-1). EITF 03-6-1 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method. EITF 03-6-1 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented will be adjusted retrospectively to conform with the provisions of EITF 03-6-1. We are evaluating the expected impact of adoption of EITF 03-6-1.

In April 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 142-3 *Determination of the Useful Life of Intangible Assets* (FSP No. FAS 142-3). FSP No. FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under Statement of Financial Accounting Standard (SFAS) No. 142, *Goodwill and Other Intangible Assets* (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141 (revised 2007), *Business Combinations*, and other GAAP. This FSP will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are evaluating the expected impact; however, we believe adoption will not impact our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an Amendment of FASB Statement No. 133* (SFAS 161). SFAS 161 requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended (SFAS 133) and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. SFAS 161 will be effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We will adopt SFAS 161 on January 1, 2009. Adoption will not impact our financial position, results of operations or cash flows.

In March 2008, the EITF issued Issue No. 07-04, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* (EITF 07-04). EITF 07-04 addresses the application of the two-class method under SFAS No. 128 in determining income per unit for master limited partnerships (MLPs) having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. EITF 07-04 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are evaluating the expected impact of adoption of EITF 07-04.

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

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measurements. The provisions of SFAS 157 were deferred for one year for certain non-financial assets and non-financial liabilities, including asset retirement obligations, goodwill, intangible assets and long-lived assets. We adopted SFAS 157 as of January 1, 2008 with the exception of those assets and liabilities that are subject to the deferral. The provisions of SFAS 157 are to be applied prospectively and require new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. See Note 10 to our Condensed Consolidated Financial Statements for additional disclosure.

Note 3 Trade Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of refined products and LPG. These purchasers include refineries, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our marketing activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

Recent turmoil in the financial markets, which escalated late in the first quarter of 2008, resulted in unprecedented actions by the Federal Reserve Bank to provide liquidity to financial institutions. In addition, in the second quarter of 2008, as the values of crude oil and refined products are at historically high levels, there have been liquidity issues at some companies with which we do business. We believe these conditions, combined with significant energy price volatility, have increased the potential credit risks associated with certain financial institutions and trading companies with which we do business. However, we have a rigorous credit review process and closely monitor these conditions in order to make a determination with respect to the amount, if any, 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 June 30, 2008 and December 31, 2007, we had received approximately $152 million and $43 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with most of our counterparties. These arrangements cover a significant portion of our transactions and also serve to mitigate credit risk.

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 June 30, 2008 and December 31, 2007, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts may vary significantly from estimated amounts.

Note 4 Acquisitions and Investment in Unconsolidated Entities

Acquisitions

In May 2008, we completed the acquisition of Rainbow Pipe Line Company, Ltd. (Rainbow) for approximately $688 million. The assets acquired include approximately (i) 480 miles of mainline crude oil pipelines, (ii) 140 miles of gathering pipelines, (iii) 570,000 barrels of tankage along the system and (iv) 1 million barrels of crude oil linefill. The system currently has a throughput capacity of approximately 200,000 barrels per day and 2007 volumes on the system averaged approximately 195,000 barrels per day. The acquired operations are reflected primarily in our transportation segment.

In anticipation of closing the Rainbow acquisition, we entered into forward currency exchange contracts, which exchanged Canadian dollars and US dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill. We recognized a gain on those positions of approximately $8 million and $3 million, respectively, which is reflected in our consolidated results of operations in the Interest income and other income (expense), net line.

The purchase price consisted of the following (in millions):

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Cash payment to sellers	$	661
Assumption of Rainbow debt (at estimated fair value)		26
Estimated transaction costs		1
Total purchase price	$	688

The purchase price allocation related to the Rainbow acquisition is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired. The preliminary purchase price allocation is as follows (in millions):

PP&E	$	425
Pipeline linefill in owned assets		143
Intangible assets		52
Goodwill		193
Future income tax liability		(110)
Assumption of working capital and other long-term assets and liabilities, including cash [1]		(15)
Total	$	688

(1) Includes approximately $16 million associated with environmental liabilities.

Investment in Unconsolidated Entities

During the three and six months ended June 30, 2008, we contributed $28 million and $40 million, respectively, to PAA/Vulcan Gas Storage, LLC, offset by distributions received of $8 million and $11 million, respectively. These contributions did not result in an increase in our ownership interest.

Note 5 Inventory and Linefill

Inventory and linefill consisted of the following (barrels in thousands and dollars in millions, except dollars per barrel amounts):

	June 30, 2008			December 31, 2007		
	Barrels	Dollars	Dollars/ Barrel (1)	Barrels	Dollars	Dollars/ Barrel (1)
Inventory						
Crude oil	6,264	$ 758	$ 121.01	7,365	$ 592	$ 80.38
LPG	5,706	413	$ 72.38	6,480	363	$ 56.02
Refined products	34	4	$ 117.65	133	11	$ 82.71
Parts and supplies	N/A	6	N/A	N/A	6	N/A
Inventory subtotal	12,004	1,181		13,978	972	

Inventory in third-party assets						
Crude oil	886	64	$ 72.23	986	64	$ 64.91
LPG	252	16	$ 63.49	175	10	$ 57.14
Inventory in third-party assets subtotal	1,138	80		1,161	74	
Pipeline linefill in owned assets						
Crude oil	8,853	424	$ 47.89	7,734	282	$ 36.46
LPG	51	2	$ 39.22	43	2	$ 46.51
Pipeline linefill in owned assets subtotal	8,904	426		7,777	284	
Total	22,046	$ 1,687		22,916	$ 1,330	

(1) The prices listed represent a weighted average associated with various grades and qualities of crude oil, LPG and refined

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products and, accordingly, are not comparable metrics with published benchmarks for such products.

Note 6 Debt

Debt consisted of the following (in millions):

		June 30, 2008		December 31, 2007
Short-term debt:				
Senior secured hedged inventory facility bearing interest at a rate of 2.9% and 5.3% at June 30, 2008 and December 31, 2007, respectively	$	420	$	476
Working capital borrowings, bearing interest at a rate of 4.1% and 5.5% at June 30, 2008 and December 31, 2007, respectively [1]		298		482
Other		1		2
Total short-term debt		719		960
Long-term debt:				
Senior notes, net of unamortized net premium and discount		3,219		2,623
Long-term debt under credit facilities and other [1]		1		1
Total long-term debt [1]		3,220		2,624
Total debt	$	3,939	$	3,584

(1) At June 30, 2008 and December 31, 2007, we have classified $298 million and $482 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) margin deposits.

In April 2008, we completed the issuance of $600 million of 6.5% Senior Notes due May 1, 2018. The senior notes were sold at 99.424% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2008. We used the net proceeds from the offering to repay amounts outstanding under our credit facilities.

In connection with the sale of the $600 million senior notes, we entered into an exchange and registration rights agreement pursuant to which we agreed to use our reasonable best efforts to, among other things:

- file, within 180 days after issuance of the senior notes, a registration statement with the SEC relating to an exchange offer for the senior notes;

- cause the registration statement to become effective within 270 days after the issuance of the senior notes; and

- consummate the exchange offer within 300 days after the issuance of the senior notes.

If we fail to meet our obligations under this agreement in a timely manner (a registration default), the per annum interest rate on the senior notes will increase for the period from the occurrence of the registration default until such time as the registration default is no longer in effect. In the event of a registration default, interest on the senior notes will increase by 0.25% during the first 90-day period following the occurrence and during the continuation of a registration default and by an additional 0.25% subsequent to the first 90-day period during which the registration default continues, up to a maximum of 0.50%.

Letters of Credit

In connection with our crude oil marketing activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At June 30, 2008 and December 31, 2007, we had outstanding letters of credit of approximately $116 million and $153 million, respectively.

Note 7 Earnings per Limited Partner Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2008 and 2007 (amounts in millions, except per unit data):

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	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 41	$ 105	$ 133	$ 190
Less: General partner s incentive distribution paid	(25)	(17)	(49)	(32)
Subtotal	16	88	84	158
Less: General partner 2% ownership		(2)	(1)	(4)
Net income available to limited partners	$ 16	$ 86	$ 83	$ 154
Denominator:				
Basic weighted average number of limited partner units outstanding	120	110	118	110
Effect of dilutive securities:				
Weighted average LTIP units (1)	1	1	1	1
Diluted weighted average number of limited partner units outstanding	121	111	119	111
Basic net income per limited partner unit	$ 0.13	$ 0.78	$ 0.70	$ 1.40
Diluted net income per limited partner unit	$ 0.13	$ 0.78	$ 0.69	$ 1.39

(1) Our LTIP awards (described in Note 9) that contemplate the issuance of common units are considered dilutive 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 SFAS No. 128, *Earnings per Share.*

Note 8 Partners Capital and Distributions

Equity Offerings

We completed the following equity offerings of our common units during the six months ended June 30, 2008 and 2007 (in millions, except units and per unit amounts):

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs (1)	Net Proceeds
April 2008	6,900,000	$ 46.31	$ 320	$ 6	$ (11)	$ 315
June 2007	6,296,172	$ 59.56	$ 375	$ 8	$	$ 383

(1) The April 2008 offering of common units was an underwritten transaction that required us to pay a gross spread; however, the direct placement of common units in June 2007 did not involve underwriters and thus did not require a gross spread payment.

LTIP Vesting

In May 2008, we issued 29,969 common units at a price of $46.58, for a fair value of approximately $1 million in connection with the settlement of vested LTIP awards.

Distributions

The following table details the distribution we declared subsequent to the second quarter of 2008 and distributions declared and paid in the six months ended June 30, 2008 and 2007, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

			Distributions Paid			
		Common	General Partner			Distributions per limited
Date Declared	**Date Paid or To Be Paid**	**Units**	**Incentive**	**2%**	**Total**	**partner unit**
July 14, 2008	August 14, 2008 [(1)]	$ 109	$ 30	$ 2	$ 141	$ 0.8875
April 17, 2008	May 15, 2008	$ 100	$ 25	$ 2	$ 127	$ 0.8650
January 16, 2008	February 14, 2008	$ 99	$ 23	$ 2	$ 124	$ 0.8500
April 17, 2007	May 15, 2007	$ 88	$ 17	$ 2	$ 107	$ 0.8125
January 16, 2007	February 14, 2007	$ 88	$ 15	$ 2	$ 105	$ 0.8000

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(1) Payable to unitholders of record on August 4, 2008, for the period April 1, 2008 through June 30, 2008.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to these acquisitions is $75 million. Following the distribution in August 2008, the aggregate remaining incentive distribution reductions related to these acquisitions will be approximately $44 million.

Note 9 Equity Compensation Plans

Long-Term Incentive Plans

For discussion of our Long-Term Incentive Plan (LTIP) awards, see Note 10 to our Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K. At June 30, 2008 we have the following LTIP awards outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date				
		2008	2009	2010	2011	2012
1.2(1)	$3.20		0.6	0.6		
1.3(2)	$3.50 - $4.00			0.2	0.7	0.4
1.3(3)	$3.50 - $4.00			0.8	0.2	0.3
3.8(4)(5)			0.6	1.6	0.9	0.7

(1) Upon our February 2007 annualized distribution of $3.20, these LTIP awards satisfied all distribution requirements and will vest upon completion of the respective service periods.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained, these awards will be forfeited. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. The awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(4) Approximately 2.0 million of our 3.8 million outstanding LTIP awards also include distribution equivalent rights (DERs), of which 1.2 million are currently earned.

(5) LTIP units outstanding do not include Class B units of Plains AAP, L.P. described below.

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, 2007	3.6	$ 37.73
Granted	0.4	$ 33.80
Vested	(0.1)	$ 37.60
Cancelled or forfeited	(0.1)	$ 48.78
Outstanding at June 30, 2008	3.8	$ 37.46

Our accrued liability at June 30, 2008 related to all outstanding LTIP awards and DERs is approximately $59 million, which includes an accrual associated with our assessment that an annualized distribution of $3.75 is probable of occurring. We have not deemed a distribution of more than $3.75 to be probable. At December 31, 2007, the accrued liability was

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approximately $51 million.

Class B Units of Plains AAP, L.P.

At June 30, 2008, approximately 154,000 Class B units have been granted and 46,000 Class B units are reserved for future grants. The total grant date fair value of the 154,000 Class B units outstanding at June 30, 2008 was approximately $34 million, of which approximately $7 million and $10 million was recognized as expense during the three months and six months ended June 30, 2008, respectively. For further discussion of the Class B units, see Note 10 to our Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K.

Other Consolidated Information

We refer to our LTIP Plans and the Class B units collectively as our equity compensation plans. The table below summarizes the expense recognized and the value of vestings (settled both in units and cash) related to our equity compensation plans (in millions):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008		2007		2008		2007	
Equity compensation expense	$	18	$	22	$	24	$	40
LTIP unit settled vestings	$	1	$	17	$	1	$	17
LTIP cash settled vestings	$	1	$	16	$	2	$	16
DER cash payments	$	1	$	1	$	2	$	2

Based on the June 30, 2008 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $67 million of additional expense over the life of our outstanding awards under our equity compensation plans related to the remaining unrecognized fair value. This estimate is based on the closing market price of our units of $45.11 at June 30, 2008. Actual amounts may differ materially as a result of a change in market price and/or probability assessment regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Plan Fair Value Amortization (1)	
2008 (2)	$	18
2009		25
2010		15
2011		6
2012		3
Total	$	67

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(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at June 30, 2008.

(2) Includes equity compensation plan fair value amortization for the remaining six months of 2008.

Note 10 Derivative Instruments and Hedging Activities

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.

Summary of Financial Impact

A summary of the earnings impact of all derivative activities, including the change in fair value of open derivatives and settled derivatives recognized in earnings, is as follows (in millions, losses designated in parentheses):

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	For the Three Months Ended June 30, 2008			For the Three Months Ended June 30, 2007		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging[1]	$ (86)	$ 162	$ 76	$ 13	$ 11	$ 24
Controlled trading program					1	1
Interest rate risk hedging	(2)		(2)		(1)	(1)
Currency exchange rate risk hedging	1	9	10	2	1	3
Total	$ (87)	$ 171	$ 84	$ 15	$ 12	$ 27

	For the Six Months Ended June 30, 2008			For the Six Months Ended June 30, 2007		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging[1]	$ (91)	$ 253	$ 162	$ (6)	$ 81	$ 75
Controlled trading program					1	1
Interest rate risk hedging					(1)	(1)
Currency exchange rate risk hedging	(1)	7	6	4		4
Total	$ (92)	$ 260	$ 168	$ (2)	$ 81	$ 79

(1) Included in Commodity price risk hedging are certain physical commodity contracts that meet the definition of a derivative and are not excluded from SFAS 133 under the normal purchase normal sale scope exception.

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 parentheses):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Derivatives that are not designated for hedge accounting [1]	$ (87)	$ 16	$ (93)	$ (1)
Ineffective portion of cash flow hedges		(1)	1	(1)
Total	$ (87)	$ 15	$ (92)	$ (2)

(1) Derivatives that do not qualify for hedge accounting consist of 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. We currently do not receive hedge accounting on certain risk management strategies due to various factors including that (i) positions have historically been immaterial, (ii) required documentation is extensive and (iii) some amount of ineffectiveness is likely. These gains or losses are generally offset by future physical positions that are not included in the mark-to-market calculation because they qualify for the normal purchase and normal sale scope exception under SFAS 133.

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

	June 30, 2008	December 31, 2007
Other current assets	$ 122	$ 56
Other long-term assets	71	26
Other current liabilities	(209)	(97)
Other long-term liabilities and deferred credits	(118)	(22)
Other		1
Net liability	$ (134)	$ (36)

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

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	June 30, 2008			December 31, 2007		
	Net Asset / (Liability)	Earnings	AOCI	Net Asset / (Liability)	Earnings	AOCI
Commodity price risk hedging	$ (138)	$ (138)	$	$ (38)	$ (48)	$ 10
Controlled trading program						
Interest rate risk hedging [(1)]	2	2		3	3	
Currency exchange rate risk hedging	2	(1)	3	(1)		(1)
	$ (134)	$ (137)	$ 3	$ (36)	$ (45)	$ 9

(1) Amounts are presented on a net basis and include both the net asset/(liability) related to our interest rate derivatives and any fair value adjustment related to our underlying debt.

In addition to the $3 million of unrealized gain as of June 30, 2008 and the $9 million of unrealized gain as of December 31, 2007 deferred to AOCI for open derivative positions, AOCI also includes deferred losses of approximately $6 million and $5 million as of June 30, 2008 and December 31, 2007, respectively, that relate to terminated interest rate hedging instruments that were settled in connection with the issuance and 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 underlying debt.

The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings, contemporaneously with (i) the related physical purchase or delivery of the underlying commodity, (ii) interest expense accruals associated with the underlying debt instruments and (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD denominated intercompany interest receivables. Of the total net loss deferred in AOCI at June 30, 2008, a net gain of approximately $27 million will be reclassified into earnings in the next twelve months. Of the remaining deferred loss in AOCI, approximately 90% is expected to be reclassed to earnings prior to 2012. 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 and six months ended June 30, 2008 and 2007, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring.

We do not offset the assets and liabilities associated with the fair value of our derivatives with amounts we have recognized related to our right to receive or our obligation to pay cash collateral. When we deposit cash collateral with our brokers, we recognize a broker receivable, which is a component of our accounts receivable. Based on the outstanding positions held in our broker accounts, our aggregate initial margin requirements with our brokers was approximately $46 million and $33 million as of June 30, 2008 and December 31, 2007, respectively. Changes in the value of our positions in the broker accounts result in increases or decreases in the amount of margin we have to provide to maintain our initial margin requirements (variation margin). Variation margin was favorable as of June 30, 2008 and December 31, 2007, respectively, and reduced the amount of our cash required to maintain our initial margin requirements.

In anticipation of closing the Rainbow acquisition, we entered into derivative instruments. See Note 4 to our Condensed Consolidated Financial Statements for further discussion.

Adoption of SFAS 157

Effective January 1, 2008, we adopted SFAS 157 which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS 157, fair value is the price that would be received from selling an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. Whenever possible, we use market data that market participants would use when pricing an asset or liability. These inputs can be either readily observable or market corroborated. We apply the market approach for recurring fair value measurements related to our derivatives. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

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Recurring Fair Value Measures

	Fair Value as of June 30, 2008 (in millions)			
	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ 106	$	$ 82	$ 188
Interest rate derivatives			2	2
Foreign currency derivatives			3	3
Total assets at fair value	$ 106	$	$ 87	$ 193
Liabilities:				
Commodity derivatives	$ (153)	$ (31)	$ (142)	$ (326)
Foreign currency derivatives			(1)	(1)
Total liabilities at fair value	$ (153)	$ (31)	$ (143)	$ (327)
Net asset/(liability) at fair value	$ (47)	$ (31)	$ (56)	$ (134)

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are commodity derivatives that are exchange traded. Exchange-traded derivative contracts include futures and exchange-traded options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy is a physical commodity supply contract that meets the definition of a derivative but is not excluded from SFAS 133 under the normal purchase and normal sale scope exception. The fair value of this commodity derivative is measured with level 1 inputs for similar but not identical instruments and therefore must be included in level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are (i) commodity derivatives that are not exchange traded, (ii) interest rate derivatives and (iii) foreign currency derivatives, which are described as follows:

- Commodity Derivatives: Level 3 commodity derivatives include OTC commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as price, volatility and correlation and do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward Treasury yields that are obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

The majority of the derivatives included in level 3 of the fair value hierarchy are classified as level 3 because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

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Rollforward of Level 3 Net Liability

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as level 3 in the fair value hierarchy (in millions):

	Six Months Ended June 30, 2008
Balance as of January 1, 2008	$ (21)
Realized and unrealized gains (losses):	
Included in earnings [1]	(81)
Included in other comprehensive income	(2)
Purchases, issuances, sales and settlements	48
Transfers into or out of level 3 [2]	
Balance as of June 30, 2008	$ (56)
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of June 30, 2008 [3]	$ (60)

(1) Gains and losses associated with level 3 commodity derivatives are reported in our condensed consolidated statements of operations as crude oil, refined products and LPG sales or purchases. Gains and losses associated with interest rate derivatives are reported in our condensed consolidated statements of operations as other income (expense). Gains and losses associated with foreign currency derivatives are reported in our condensed consolidated statements of operations as either crude oil, refined products and LPG sales or other income (expense).

(2) Transfers into or out of level 3 represent existing assets or liabilities that were either previously categorized at a higher level for which the inputs to the model became unobservable or that were previously classified as level 3 for which the lowest significant input became observable during the period. There were no transfers into or out of level 3 during the period.

(3) The change in unrealized gains and losses related to our level 3 assets and liabilities still held at the end of the period are either recognized in earnings or deferred in AOCI through the application of hedge accounting. Unrealized gains and losses related to our level 3 derivatives that are still held at June 30, 2008 that are recognized in earnings are included in our condensed consolidated statements of operations as crude oil, refined products and LPG sales or purchases for our commodity derivatives, other income (expense) for our interest rate derivatives and crude oil, refined products and LPG sales or other income (expense) for our foreign currency derivatives.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and are therefore offset by the underlying transactions. Accordingly, gains or losses associated with level 3 balances do not necessarily reflect trends occurring in the underlying business.

Note 11 Income Taxes

U.S. Federal and State Taxes

As a master limited partnership, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. We are subject to state income taxes in some states but the expense is immaterial.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which is a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in 2007 that imposes entity-level taxes on certain types of flow-through entities. This legislation includes safe harbor guidelines that grandfather certain existing entities (which would include us) and delay the effective date of such legislation until 2011 provided that such entities do not exceed the normal growth guidelines. Although we continuously review acquisition opportunities that, if consummated, could cause us to exceed the normal growth guidelines, we believe that we are currently within the normal growth guidelines.

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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 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 $4 million to $5 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. The 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 civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with the DOJ and the EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that the EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by the EPA, and will continue to engage in discussions with the EPA and the DOJ with respect to such mitigating circumstances and factors, as well as the injunctive remedies proposed.

On November 15, 2006, we completed the Pacific merger. 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 have been incurred and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, 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 $1.4 million, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered 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 alleged 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 any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are in settlement discussions with the State of California.

The EPA is also pursuing a claim in connection with this release and 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 $4.2 million. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and

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intend to pursue discussions with the EPA regarding such defenses and mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be claimed by the EPA cannot be ascertained. While we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE contamination at the Pacific Atlantic Terminals LLC (PAT) facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $12 million. Both Exxon and GATX were prior owners of the terminal. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We intend to vigorously defend against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

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 mitigative costs or the imposition of fines and penalties.

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 a program designed to help prevent releases, 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 procedures, remove selected assets from service and spend capital to upgrade the assets. The inclusion of additional miles of pipe in our operations may, however, 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, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas.

At June 30, 2008, our reserve for environmental liabilities totaled approximately $47 million, of which approximately $12 million is classified as short-term and $35 million is classified as long-term. At June 30, 2008, we have recorded receivables totaling approximately $4 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred in excess of this reserve may be higher and may potentially 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, natural disaster or terrorist activity. 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.

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, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 13 Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. The following table reflects certain financial data for each segment for the periods indicated (in millions):

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	Transportation(1)	Facilities	Marketing	Total
Three Months Ended June 30, 2008				
Revenues:				
External Customers	$ 143	$ 37	$ 8,880	$ 9,060
Intersegment (2)	89	28	1	118
Total revenues of reportable segments	$ 232	$ 65	$ 8,881	$ 9,178
Equity earnings of unconsolidated entities	$ 1	$ 3	$	$ 4
Segment profit (3) (4) (5)	$ 106	$ 36	$ (5)	$ 137
SFAS 133 impact (3)	$	$	$ (85)	$ (85)
Maintenance capital	$ 11	$ 5	$ 1	$ 17
Three Months Ended June 30, 2007				
Revenues:				
External Customers	$ 109	$ 31	$ 3,778	$ 3,918
Intersegment (2)	85	23	10	118
Total revenues of reportable segments	$ 194	$ 54	$ 3,788	$ 4,036
Equity earnings of unconsolidated entities	$ 1	$ 4	$	$ 5
Segment profit (3) (4) (5)	$ 80	$ 29	$ 101	$ 210
SFAS 133 impact (3)	$	$	$ 15	$ 15
Maintenance capital	$ 9	$ 2	$	$ 11
Six Months Ended June 30, 2008				
Revenues:				
External Customers	$ 268	$ 70	$ 15,917	$ 16,255
Intersegment (2)	169	54	1	224
Total revenues of reportable segments	$ 437	$ 124	$ 15,918	$ 16,479
Equity earnings of unconsolidated entities	$ 3	$ 4	$	$ 7
Segment profit (3) (4) (5)	$ 195	$ 68	$ 52	$ 315
SFAS 133 impact (3)	$	$	$ (92)	$ (92)
Maintenance capital	$ 25	$ 10	$ 2	$ 37
Six Months Ended June 30, 2007				
Revenues:				
External Customers	$ 211	$ 57	$ 7,880	$ 8,148
Intersegment (2)	162	42	17	221
Total revenues of reportable segments	$ 373	$ 99	$ 7,897	$ 8,369
Equity earnings of unconsolidated entities	$ 2	$ 6	$	$ 8
Segment profit (3) (4) (5)	$ 153	$ 51	$ 167	$ 371
SFAS 133 impact (3)	$	$	$ (2)	$ (2)
Maintenance capital	$ 13	$ 6	$ 3	$ 22

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(1) At June 30, 2008, our total assets were approximately $2.0 billion higher than our total assets at December 31, 2007. Such increase in total assets is approximately evenly divided between our transportation segment and marketing segment.

(2) Intersegment sales are conducted at posted tariff rates or at the same rates as those charged to third parties. For further discussion, see Analysis of Operating Segments under Item 7 of our 2007 Annual Report on Form 10-K.

(3) Amounts related to SFAS 133 are included in marketing revenues and impact segment profit. The SFAS 133 charge within the marketing segment for the three and six months ended June 30, 2008 excludes losses of $2 million and less than $1 million, respectively, related to interest rate derivatives. For the three and six months ended June 30, 2007, there was a loss of less than $1 million related to interest rate derivatives. These gains and losses are included in interest income and other income (expense), net, but do not impact segment profit.

(4) Marketing segment profit includes interest expense on contango inventory purchases of approximately $4 million and $13 million for the three months ended June 30, 2008 and 2007, respectively, and approximately $10 million and $25 million for the six months ended June 30, 2008 and 2007, respectively.

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(5) The following table reconciles segment profit to net income (in millions):

	For the Three Months Ended June 30, 2008	For the Three Months Ended June 30, 2007	For the Six Months Ended June 30, 2008	For the Six Months Ended June 30, 2007
Segment profit	$ 137	$ 210	$ 315	$ 371
Depreciation and amortization	(52)	(52)	(100)	(92)
Interest expense	(49)	(41)	(91)	(82)
Interest income and other income, net	10		12	5
Income tax expense	(5)	(12)	(3)	(12)
Net income	$ 41	$ 105	$ 133	$ 190

Note 14 Supplemental Condensed Consolidating Financial Information

For purposes of the following footnote, Plains All American is referred to as Parent. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2007 Annual Report on Form 10-K for detail of which subsidiaries are classified as Guarantor Subsidiaries and which subsidiaries are classified as Non-Guarantor Subsidiaries. There have been no material changes in the entities that constitute our guarantor and non-guarantor subsidiaries since December 31, 2007.

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 (all amounts in millions):

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Condensed Consolidating Balance Sheet
As of June 30, 2008

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,782	$ 4,611	$ 105	$ (2,902)	$ 4,596
Property plant and equipment, net		4,381	635		5,016
Investment in unconsolidated entities	4,060	1,067		(4,876)	251
Other assets	25	1,684	317		2,026
Total assets	$ 6,867	$ 11,743	$ 1,057	$ (7,778)	$ 11,889
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 62	$ 7,532	$ 56	$ (2,902)	$ 4,748
Long-term debt	3,218	2			3,220
Other long-term liabilities		333	1		334
Total liabilities	3,280	7,867	57	(2,902)	8,302
Partners Capital	3,587	3,876	1,000	(4,876)	3,587
Total liabilities and partners capital	$ 6,867	$ 11,743	$ 1,057	$ (7,778)	$ 11,889

As of December 31, 2007

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,277	$ 3,858	$ 91	$ (2,553)	$ 3,673
Property plant and equipment, net		3,791	628		4,419
Investment in unconsolidated entities	3,881	863		(4,529)	215
Other assets	22	1,259	318		1,599
Total assets	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 134	$ 5,911	$ 237	$ (2,553)	$ 3,729
Long-term debt	2,622	2			2,624
Other long-term liabilities		128	1		129
Total liabilities	2,756	6,041	238	(2,553)	6,482
Partners Capital	3,424	3,730	799	(4,529)	3,424
Total liabilities and partners capital	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906

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Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2008

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$	$ 307	$ 29	$	$ 336
Field operating costs		(143)	(9)		(152)
General and administrative expenses		(47)	(4)		(51)
Depreciation and amortization	(1)	(46)	(5)		(52)
Operating income (loss)	(1)	71	11		81
Equity earnings in unconsolidated entities	91	12		(99)	4
Interest expense	(47)	(2)			(49)
Interest and other income (expense), net	(2)	12			10
Income tax expense		(5)			(5)
Net income (loss)	$ 41	$ 88	$ 11	$ (99)	$ 41

Three Months Ended June 30, 2007

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$	$ 357	$ 32	$	$ 389
Field operating costs		(126)	(10)		(136)
General and administrative expenses		(48)			(48)
Depreciation and amortization	(1)	(46)	(5)		(52)
Operating income (loss)	(1)	137	17		153
Equity earnings in unconsolidated entities	147	17		(159)	5
Interest expense	(41)				(41)
Interest and other income (expense), net					
Income tax expense		(12)			(12)
Net income (loss)	$ 105	$ 142	$ 17	$ (159)	$ 105

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

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	Six Months Ended June 30, 2008									
		Parent		Combined Guarantor Subsidiaries		Combined Non-Guarantor Subsidiaries		Eliminations		Consolidated
Net operating revenues [1]	$		$	635	$	60	$			695
Field operating costs				(275)		(22)				(297)
General and administrative expenses				(84)		(6)				(90)
Depreciation and amortization		(1)		(89)		(10)				(100)
Operating income (loss)		(1)		187		22				208
Equity earnings in unconsolidated entities		224		24				(241)		7
Interest expense		(90)		(1)						(91)
Interest and other income (expense), net				12						12
Income tax expense				(3)						(3)
Net income (loss)	$	133	$	219	$	22	$	(241)	$	133

	Six Months Ended June 30, 2007									
		Parent		Combined Guarantor Subsidiaries		Combined Non-Guarantor Subsidiaries		Eliminations		Consolidated
Net operating revenues [1]	$		$	659	$	60	$		$	719
Field operating costs				(243)		(18)				(261)
General and administrative expenses				(96)		1				(95)
Depreciation and amortization		(1)		(80)		(11)				(92)
Operating income (loss)		(1)		240		32				271
Equity earnings in unconsolidated entities		273		33				(298)		8
Interest expense		(82)								(82)
Interest and other income (expense), net				5						5
Income tax expense				(12)						(12)
Net income (loss)	$	190	$	266	$	32	$	(298)	$	190

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

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Condensed Consolidating Statements of Cash Flows
Six Months Ended June 30, 2008

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 133	$ 219	$ 22	$ (241)	$ 133
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	1	89	10		100
SFAS 133 mark-to-market adjustment		92			92
Equity compensation expense		24			24
Gain on foreign currency revaluation		(10)			(10)
Equity earnings in unconsolidated entities, net of distributions	(214)	(23)		242	5
Deferred income tax expense		(3)			(3)
Other		(5)			(5)
Changes in assets and liabilities, net of acquisitions	(541)	800	(18)	(1)	240
Net cash provided by operating activities	(621)	1,183	14		576
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions		(661)			(661)
Additions to property and equipment		(287)	(14)		(301)
Investment in unconsolidated entities	(40)				(40)
Proceeds from sales of assets		15			15
Net cash used in investing activities	(40)	(933)	(14)		(987)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		(204)			(204)
Net repayments on short-term letter of credit and hedged inventory facility		(56)			(56)
Proceeds from the issuance of senior notes	597				597
Net proceeds from the issuance of common units	315				315
Distributions paid to common unitholders and general partner	(251)				(251)
Other financing activities	(5)				(5)
Net cash provided by (used in) financing activities	656	(260)			396
Effect of translation adjustment on cash		2			2
Net decrease in cash and cash equivalents	(5)	(8)			(13)
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ (4)	$ 15	$	$	$ 11

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	Six Months Ended June 30, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 190	$ 266	$ 32	$ (298)	$ 190
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	1	80	11		92
SFAS 133 mark-to-market adjustment		2			2
Gain on linefill					
Inventory valuation adjustment		1			1
Gain on sale of investment assets		(4)			(4)
Equity compensation expense		40			40
Gain on foreign currency revaluation		(2)			(2)
Noncash amortization of terminated interest rate hedging instruments	1				1
Equity earnings in unconsolidated entities, net of distributions	(272)	(33)		297	(8)
Deferred income tax expense		11			11
Changes in assets and liabilities, net of acquisitions	(83)	64	(32)	1	(50)
Net cash provided by operating activities	(163)	425	11		273
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquistions		(18)			(18)
Additions to property and equipment		(256)	(11)		(267)
Investment in unconsolidated entities	(9)				(9)
Cash paid for linefill in assets owned		(15)			(15)
Proceeds from sales of assets		13			13
Net cash used in investing activities	(9)	(276)	(11)		(296)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings/(repayments) on revolving credit facility		(175)			(175)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility		52			52
Net proceeds from the issuance of common units	383				383
Distributions paid to common unitholders and general partner	(212)				(212)
Other financing activities					
Net cash provided by (used in) financing activities	171	(123)			48
Effect of translation adjustment on cash		9			9
Net increase (decrease) in cash and cash equivalents	(1)	35			34
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 1	$ 44	$	$	$ 45

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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 and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2007 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Condensed Consolidated Financial Statements.

Highlights Second Quarter of 2008 and 2007 (in millions, except per unit data)

	Three Months Ended June 30,		Three Months Favorable/(Unfavorable) Variance		Six Months Ended June 30,		Six Months Favorable/(Unfavorable) Variance	
	2008	**2007**	**$**	**%**	**2008**	**2007**	**$**	**%**
Transportation segment profit	$ 106	$ 80	$ 26	33%	$ 195	$ 153	$ 42	27%
Facilities segment profit	36	29	7	24%	68	51	17	33%
Marketing segment profit	(5)	101	(106)	(105)%	52	167	(115)	(69)%
Segment profit	137	210	(73)	(35)%	315	371	(56)	(15)%
Depreciation and amortization	(52)	(52)		0%	(100)	(92)	(8)	(9)%
Interest expense	(49)	(41)	(8)	(20)%	(91)	(82)	(9)	(11)%
Interest income and other income (expense), net	10		10	N/A	12	5	7	140%
Income tax benefit (expense)	(5)	(12)	7	58%	(3)	(12)	9	75%
Net income	$ 41	$ 105	$ (64)	(61)%	$ 133	$ 190	$ (57)	(30)%
Earnings per basic limited partner unit	$ 0.13	$ 0.78	$ (0.65)	(83)%	$ 0.70	$ 1.40	$ (0.70)	(50)%
Earnings per diluted limited partner unit	$ 0.13	$ 0.78	$ (0.65)	(83)%	$ 0.69	$ 1.39	$ (0.70)	(50)%
Basic weighted average units outstanding	120	110	10	9%	118	110	8	7%
Diluted weighted average units outstanding	121	111	10	9%	119	111	8	7%

Key items impacting the comparison of the first six months of 2008 to the first six months of 2007 include:

- Two months contributions to earnings from the May 2008 acquisition of Rainbow Pipe Line Company, Ltd. (Rainbow), which was completed for consideration of approximately $688 million, as well as increased earnings resulting from prior acquisitions;

- Increased earnings from expansion activities that became operational subsequent to June 30, 2007;

- Decreased earnings in the marketing segment resulting from less favorable market conditions;

- A loss of approximately $92 million related to the mark-to-market impact for open derivative instruments (compared to a loss of approximately $2 million for the first six months of 2007). This larger than usual mark-to-market adjustment is due to the significant increase in crude oil prices and volatility during the period;

- Equity compensation plan expense of $24 million compared to approximately $40 million for the prior period. The decreased expense is primarily the result of the decrease in unit price for the first six months of 2008 compared to the increase in unit price for the first six months of 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence in the first six months of 2007;

- The issuance of $600 million of senior notes for net proceeds of approximately $597 million and the issuance of approximately 7 million limited partner units for net proceeds of approximately $315 million; and

- Capital expenditures for internal growth projects of $256 million for the first half of 2008, which represent approximately 56% of the 2008 planned expansion capital expenditures.

Acquisitions and Internal Growth Projects

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

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	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Acquisition capital	$ 688	$ 26
Investment in unconsolidated entities [1]	40	9
Internal growth projects	256	257
Maintenance capital	37	22
	$ 1,021	$ 314

(1) During the six months ended June 30, 2008, we contributed $40 million to PAA/Vulcan Gas Storage, LLC. See Note 4 to our Condensed Consolidated Financial Statements.

Acquisitions

In May 2008, we completed the Rainbow acquisition for approximately $688 million. See Note 4 to our Condensed Consolidated Financial Statements for discussion of the Rainbow acquisition, including details of the purchase price and related allocation.

Internal Growth Projects

Our internal growth projects include the construction and expansion of pipeline systems and crude oil and LPG storage facilities. Following are some of the more notable projects undertaken in 2008 and the forecasted expenditures for the year (in millions):

Projects	2008
Patoka tankage	$ 46
Paulsboro tankage	30
Kerrobert mainline connection	21
Fort Laramie tank expansion	22
Pier 400 [1]	13
West Hynes tankage	13
Kerrobert facility	12
Edmonton tankage and connections	11
Other projects, including acquisition related expansion projects [2]	292
Total [3]	$ 460

(1) This project requires approval from a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time. Does not include intangible expenditures of approximately $5 million for emission reduction credits.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing and carryover of projects started in 2007, including the Salt Lake City pipeline, for which estimated costs have increased approximately $50 million over the May 29, 2008 estimate, primarily due to adverse soil conditions. Such amount also includes expansion capital projects associated with the Rainbow acquisition that are expected to be commenced in 2008.

(3) Approximately $256 million of capital expenditures for expansion projects was incurred in the first six months of 2008.

We forecasted approximately $70 million in capital expenditures for maintenance projects during calendar year 2008, of which approximately $37 million was incurred in the first six months.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. In order to evaluate segment performance, management focuses on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 15 to our Consolidated Financial Statements in our 2007 Annual Report on Form 10-K for further discussion on how we evaluate segment performance.

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Transportation

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Three Months Favorable (Unfavorable) Variance $	Three Months Favorable (Unfavorable) Variance %	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Favorable (Unfavorable) Variance $	Six Months Favorable (Unfavorable) Variance %
Revenues								
Tariff activities	$ 199	$ 164	$ 35	21%	$ 373	$ 317	$ 56	18%
Trucking	33	30	3	10%	64	56	8	14%
Total transportation revenues	232	194	38	20%	437	373	64	17%
Costs and Expenses								
Trucking costs	(23)	(20)	(3)	(15)%	(45)	(38)	(7)	(18)%
Field operating costs (excluding equity compensation expense)	(81)	(73)	(8)	(11)%	(160)	(140)	(20)	(14)%
Equity compensation expense - operations (2)	(1)	(3)	2	67%	(2)	(5)	3	60%
Segment G&A expenses (excluding equity compensation expense) (3)	(14)	(11)	(3)	(27)%	(28)	(24)	(4)	(17)%
Equity compensation expense - general and administrative (2)	(8)	(8)		%	(10)	(15)	5	33%
Equity earnings in unconsolidated entities	1	1		%	3	2	1	50%
Segment profit	$ 106	$ 80	$ 26	33%	$ 195	$ 153	$ 42	27%
Maintenance capital	$ 11	$ 9	$ 2	22%	$ 25	$ 13	$ 12	92%
Segment profit per barrel	$ 0.38	$ 0.30	$ 0.08	27%	$ 0.37	$ 0.30	$ 0.07	23%

Average Daily Volumes (in thousands of barrels) (4)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Three Months Favorable (Unfavorable) Variance Volumes	Three Months Favorable (Unfavorable) Variance %	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Favorable (Unfavorable) Variance Volumes	Six Months Favorable (Unfavorable) Variance %
Tariff activities								
All American	43	47	(4)	(9)%	45	48	(3)	(6)%
Basin	377	407	(30)	(7)%	370	374	(4)	(1)%
Capline	247	231	16	7%	218	233	(15)	(6)%
Line 63/Line 2000	160	181	(21)	(12)%	161	181	(20)	(11)%
Salt Lake City Area Systems	96	105	(9)	(9)%	96	101	(5)	(5)%
West Texas/New Mexico Area Systems	427	395	32	8%	402	381	21	6%
Manito	72	74	(2)	(3)%	70	74	(4)	(5)%
Rainbow	132		132	N/A	66		66	N/A
Rangeland	59	64	(5)	(8)%	60	64	(4)	(6)%
Refined products	107	105	2	2%	111	110	1	1%
Other	1,229	1,163	66	6%	1,206	1,125	81	7%
Tariff activities total	2,949	2,772	177	6%	2,805	2,691	114	4%
Trucking	89	107	(18)	(17)%	93	108	(15)	(14)%
Transportation total	**3,038**	**2,879**	**159**	**6%**	**2,898**	**2,799**	**99**	**4%**

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(1) Revenues and costs and expenses include intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segment 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.

Transportation segment profit and segment profit per barrel for the three- and six-month periods ended June 30, 2008 were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for both the three- and six-month periods ended June 30, 2008 as compared to the same periods ended June 30, 2007. The discussion below presents the significant variances in revenues and average daily volumes between the comparative periods:

- Acquisitions - Revenues and volumes for the three and six months ended June 30, 2008 were impacted by the Rainbow acquisition, which occurred in May 2008, and various other systems brought into service throughout the year. The Rainbow acquisition contributed approximately $12 million of additional revenues for both the three and six months ended June 30, 2008, and additional volumes of approximately 132 thousand barrels per day and 66 thousand barrels per day for the same periods, respectively.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. 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. The average price of crude oil was substantially higher during 2008 than it was in 2007. As a result, loss allowance revenues increased by approximately $10 million and $20 million for the three and six months ended June 30, 2008 compared to the three and six months ended June 30, 2007, respectively.

- Expansion projects - The Cheyenne expansion project, completed during the latter half of 2007, contributed additional revenues of approximately $2 million and $4 million for the three and six months ended June 30, 2008, respectively, as well as additional volumes of approximately 34 thousand barrels per day and 33 thousand barrels per day for the same periods, respectively.

- Foreign exchange - Revenues from our Canadian pipeline systems increased for the three and six months ended June 30, 2008, compared to the three and six months ended June 30, 2007, primarily due to the appreciation of Canadian currency. The Canadian to US dollar exchange rate appreciated to an average of $1.01:1 for the three months ended June 30, 2008 compared to an average of $1.10:1 for the three months ended June 30, 2007. The average exchange rate for the six months ended June 30, 2008 was $1.01:1 compared to an average of $1.13:1 for the six months ended June 30, 2007.

- Trucking - Revenues from trucking increased for the six months ended June 30, 2008 compared to the six months ended June 30, 2007 due to (i) contribution from an acquisition that was completed during the first quarter of 2007 and (ii) an increase in rates during the second quarter of 2007. Revenues from trucking for the three months ended June 30, 2008 were consistent with those for the three months ended June 30, 2007. Volumes from trucking decreased for the three and six months ended June 30, 2008 compared to the same periods for 2007 due to (i) a strategic decision to replace short haul contracts with more profitable long haul contracts and (ii) a decrease in demand due to warmer weather.

- Rate increases - Rates increased on the majority of our pipeline systems in the third quarter of 2007 and resulted in increased revenues for the three and six months ended June 30, 2008 compared to the three and six months ended June 30, 2007. Rates on these systems are increased through indexing by the FERC (on July 1 of each year), by state and Canadian regulatory agencies and/or through market-based escalation.

- Other factors - Our revenues and volumes are impacted by miscellaneous other factors for the respective periods including, but not limited to, refinery turnarounds and downtime and new or revised contracts.

Field Operating Costs. The 2008 increased costs primarily relate to (i) utilities costs, which increased due to higher market prices, (ii) payroll and employee benefits, (iii) increased maintenance costs and (iv) additional pipeline inspection and integrity maintenance costs in the first quarter of 2008 compared to the first quarter of 2007. Pipeline inspection and integrity maintenance costs for the second quarter of 2008 were comparable to the costs for the second quarter of 2007.

General and Administrative Expenses. Our G&A expenses were impacted in 2008 by equity compensation charges that decreased in 2008 compared to 2007, primarily as a result of the decrease in unit price for the first six months of 2008 compared to the increase in unit price for the first six months of 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence in the first six months of 2007.

Maintenance Capital. The increase in maintenance capital for the six months ended June 30, 2008 is primarily due to the timing of current projects and projects that were carried over from 2007. In addition, maintenance capital in the first six months of 2007 was lower than forecast.

Facilities

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

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Operating Results (1) **(in millions, except per barrel amounts)**	**Three Months Ended June 30,**		**Three Months Favorable (Unfavorable) Variance**		**Six Months Ended June 30,**		**Six Months Favorable (Unfavorable) Variance**	
	2008	**2007**	**$**	**%**	**2008**	**2007**	**$**	**%**
Storage and terminalling revenues (1)	$ 65	$ 54	$ 11	20%	$ 124	$ 99	$ 25	25%
Field operating costs	(25)	(21)	(4)	(19)%	(48)	(39)	(9)	(23)%
Segment G&A expenses (excluding equity compensation expense) (2)	(4)	(5)	1	20%	(8)	(10)	2	20%
Equity compensation expense - general and administrative (3)	(3)	(3)		%	(4)	(5)	1	20%
Equity earnings in unconsolidated entities	3	4	(1)	(25)%	4	6	(2)	(33)%
Segment profit	$ 36	$ 29	$ 7	24%	$ 68	$ 51	$ 17	33%
Maintenance capital	$ 5	$ 2	$ 3	150%	$ 10	$ 6	$ 4	67%
Segment profit per barrel	$ 0.21	$ 0.21	$	%	$ 0.20	$ 0.19	$ 0.01	5%

Volumes (4)	**Three Months Ended June 30,**		**Three Months Favorable (Unfavorable) Variance**		**Six Months Ended June 30,**		**Six Months Favorable (Unfavorable) Variance**	
	2008	**2007**	**Volumes**	**%**	**2008**	**2007**	**Volumes**	**%**
Crude oil, refined products and LPG storage (5) (average monthly capacity in millions of barrels)	55	43	12	28%	54	43	11	26%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet (bcf))	14	13	1	8%	13	13		%
LPG processing (average throughput in thousands of barrels per day)	17	20	(3)	(15)%	16	17	(1)	(6)%
Facilities total (average monthly capacity in millions of barrels) (6)	58	46	12	26%	57	45	12	26%

(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 segment 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 business activities that exist during each period.

(3) Equity compensation expense related to our equity compensation plans.

(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) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for

these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

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

Facilities segment profit and segment profit per barrel for the three- and six-month periods ended June 30, 2008 were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for the three and six months ended June 30, 2008 compared to the three and six months ended June 30, 2007. The table below presents the significant variances in revenues (in millions) and volumes (in millions of barrels per month) between the comparative periods:

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		Revenues	Volumes Crude Oil, Refined Products and LPG Storage(1)	Volumes Natural Gas Storage(2)	Volumes LPG and Crude Processing(3)
Three Months Ended June 30, 2008 compared to Three Months Ended June 30, 2007:					
(Increase)/Decrease due to:					
Acquisitions (4)	$	4	4		
Expansions (5)		5	7		
Other (6)		2	1	1	(3)
Total variance	**$**	**11**	**12**	**1**	**(3)**

		Revenues	Volumes Crude Oil, Refined Products and LPG Storage(1)	Volumes Natural Gas Storage(2)	Volumes LPG and Crude Processing(3)
Six Months Ended June 30, 2008 compared to Six Months Ended June 30, 2007:					
(Increase)/Decrease due to:					
Acquisitions (4)	$	7	4		
Expansions (5)		10	6		
Other (6)		8	1		(1)
Total variance	**$**	**25**	**11**		**(1)**

(1) Average monthly capacity (in millions of barrels).

(2) Average monthly capacity (in bcf).

(3) Barrels per day (in thousands).

(4) Revenues and volumes were impacted in 2008 by 2007 acquisitions. The Bumstead and Tirzah acquisitions were completed in the third and fourth quarters of 2007 and, in the aggregate, contributed additional revenues of approximately $4 million and $7 million for the three and six months ended June 30, 2008, respectively, and additional volumes of approximately 4 million barrels for both of the respective periods.

(5) Expansion projects also resulted in an increase in revenues and volumes in the second quarter and first six months of 2008 compared to the second quarter and first six months of 2007. The Cushing, Martinez and St. James expansion projects that were completed either during the first six months of 2008 or in the last six months of 2007 contributed additional revenues of approximately $5 million and $10 million for the three and six months ended June 30, 2008, and additional aggregate volumes of approximately 7 million barrels and 6 million barrels for the respective periods.

(6) Other immaterial variances.

Field Operating Costs. Our field operating costs were impacted primarily by the acquisitions completed during 2007 and the additional tankage added in 2008 and 2007. Of the total increase for the three and six months ended June 30, 2008 compared to the prior periods, $1 million and $2 million, respectively, relates to the operating costs (including increased utilities expense) associated with the Bumstead and Tirzah facilities, which were acquired in the third and fourth quarters of 2007. Expansion projects, including Cushing, St. James and Martinez, contributed additional operating costs for the three and six months ended June 30, 2008 compared to the prior periods.

Marketing

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

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	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Three Months Favorable (Unfavorable) Variance $	Three Months Favorable (Unfavorable) Variance %	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Favorable (Unfavorable) Variance $	Six Months Favorable (Unfavorable) Variance %
Operating Results (in millions, except per barrel amounts) (1)								
Revenues (2)	$ 8,881	$ 3,788	$ 5,093	134%	$ 15,918	$ 7,897	$ 8,021	102%
Purchases and related costs (3)	(8,819)	(3,627)	(5,192)	(143)%	(15,739)	(7,612)	(8,127)	(107)%
Field operating costs	(45)	(39)	(6)	(15)%	(87)	(77)	(10)	(13)%
Segment G&A expenses (excluding equity compensation expense) (4)	(16)	(13)	(3)	(23)%	(32)	(26)	(6)	(23)%
Equity compensation expense - general and administrative (5)	(6)	(8)	2	25%	(8)	(15)	7	47%
Segment profit (2)	$ (5)	$ 101	$ (106)	(105)%	$ 52	$ 167	$ (115)	(69)%
SFAS 133 mark-to-market loss (2)	$ (85)	$ 15	$ (100)	(667)%	$ (92)	$ (2)	$ (90)	(4500)%
Maintenance capital	$ 1	$	$ 1	N/A	$ 2	$ 3	$ (1)	(33)%
Segment profit per barrel (6)	$ (0.06)	$ 1.32	$ (1.38)	(105)%	$ 0.32	$ 1.07	$ (0.75)	(70)%

Average Daily Volumes (in thousands of barrels per day) (7)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Three Months Favorable (Unfavorable) Variance Volumes	Three Months Favorable (Unfavorable) Variance %	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Favorable (Unfavorable) Variance Volumes	Six Months Favorable (Unfavorable) Variance %
Crude oil lease gathering	672	707	(35)	(5)%	676	694	(18)	(3)%
Refined products	24	13	11	85%	22	8	14	175%
LPG sales	51	45	6	13%	93	89	4	4%
Waterborne foreign crude imported	102	78	24	31%	89	72	17	24%
Marketing total	849	843	6	1%	880	863	17	2%

(1) Revenues and costs include intersegment amounts.
(2) Amounts related to SFAS 133 are included in revenues and impact segment profit.
(3) Purchases and related costs include interest expense on hedged inventory purchases of approximately $4 million and $10 million for the three and six months ended June 30, 2008, respectively, compared to $13 million and $25 million for the three and six months ended June 30, 2007, respectively.
(4) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segment 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.
(5) Equity compensation expense related to our equity compensation plans.
(6) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes and waterborne foreign crude volumes.
(7) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Revenues and purchases and related costs. Our revenues and purchases and related costs for the second quarter and first six months of 2008 increased compared to the second quarter and first six months of 2007, primarily due to an increase in the average NYMEX price for crude oil. The NYMEX average price was $124 and $111 for the second quarter and first six months of 2008, respectively, compared to $65 and $62 for the second quarter and first six months of 2007, respectively.

Marketing segment profit and segment profit per barrel for the three- and six-month periods ended June 30, 2008 were impacted by the following:

- Market conditions were not as favorable in the second quarter and first six months of 2008 as they were in the second quarter and first six months of 2007.

- Although there was significant volatility in absolute crude oil prices during the first six months of 2008, the market structure was generally range-bound in the second quarter of 2008 between $0.50 per barrel backwardation and $0.50 per barrel contango. The market structure was backwardated for the first quarter of 2008. In contrast, the crude oil market was in contango for the first six months of 2007. A contango market is favorable to our commercial strategies that are associated with storage tankage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. In a backwardated crude oil market, there is little incentive to store crude oil as current prices are above future delivery prices. The monthly time spread of prices averaged approximately $(0.11) (backwardated) for the second quarter

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of 2008 versus an average contango spread of $1.28 for the second quarter of 2007. For the first six months of 2008, the monthly time spread of prices averaged approximately $(0.29) (backwardated) versus an average contango spread of $1.24 for the first six months of 2007. If the market remains in the slightly backwardated to transitional structure that has generally prevailed since July 2007, future results from our marketing segment may be less than those generated during the more favorable contango market conditions that prevailed throughout the first half of 2007.

- The NYMEX benchmark price of crude oil ranged from approximately $86 to $144 per barrel during the first six months of 2008 and from approximately $50 to $71 per barrel for the comparable period in 2007. The NYMEX WTI crude oil benchmark prices reached a record high of $144 per barrel in June 2008 (and has since been exceeded). During the first half of 2007, the volatility in crude oil prices was accompanied by significantly high volatility in market structure and differentials that allowed us to utilize risk management strategies to optimize and enhance margins of our gathering and marketing activities. Although there was significant outright price volatility in the first half of 2008, there was limited volatility in the market structure and differentials as compared to the first half of 2007.

- Results from our LPG operations were lower in the second quarter and first six months of 2008 as compared to the respective periods of 2007. Profits in the second quarter and first six months of 2008 were negatively impacted by the timing of recognizing profits during the LPG season due to average costing of inventory and the sales price of contracts presented for delivery (more profits were recognized earlier in the April 2007 to March 2008 season).

- Revenues for the second quarter of 2008 include a mark-to-market loss under SFAS 133 of approximately $85 million compared to a gain of approximately $15 million for the second quarter of 2007. Revenues for the first six months of 2008 include a SFAS 133 loss of approximately $92 million compared to a loss of approximately $2 million for the first six months of 2007. The mark-to-market loss during 2008 was caused by the significant increase in crude oil prices. The loss was primarily related to risk management strategies for which we currently do not receive hedge accounting due to various factors including that (i) positions have historically been immaterial, (ii) required documentation is extensive and (iii) some amount of ineffectiveness is likely. These gains or losses are generally offset by future physical positions that are not included in the mark-to-market calculation because they qualify for the normal purchase and normal sale scope exception under SFAS 133. See Note 10 to our Condensed Consolidated Financial Statements for discussion of our hedging activities.

- Field operating costs increased in the second quarter and first six months of 2008 compared to the second quarter and first six months of 2007 primarily as a result of increases in transportation-related costs, including fuel and third-party trucking fees.

- Equity compensation charges decreased in 2008 compared to 2007 primarily as a result of the decrease in unit price for the first six months of 2008 compared to the increase in unit price for the first six months of 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence in the first six months of 2007.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased $8 million for the first six months of 2008 compared to the comparable 2007 period primarily as a result of an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. The expense for the second quarter of 2008 is comparable to that of the second quarter of 2007. The expense for the second quarter of 2008 reflects an increased amount of depreciable assets offset by a smaller net loss on the disposition of assets relative to the second quarter of 2007.

Interest Expense. Interest expense increased $8 million and $9 million for the second quarter and first six months of 2008 in comparison to the second quarter and first six months of 2007. The increase primarily resulted from the issuance of $600 million senior notes completed in April 2008 and imputed interest related to the Rainbow acquisition. These increases were partially offset by lower interest charges under our short-term credit facilities as a result of lower borrowings.

Interest Income and Other Income (Expense), Net. Interest income and other income (expense), net, increased $10 million and $7 million for the second quarter and first six months of 2008 in comparison to the second quarter and first six months of 2007. The increase primarily resulted from gains on the forward currency exchange hedge and commodity price risk hedge that we entered into as part of the Rainbow acquisition. See Note 4 to our Condensed Consolidated Financial Statements for further discussion of these hedges.

Income Tax Expense. Income tax expense decreased $7 million and $9 million for the three and six months ended June 30, 2008 in comparison to the three and six months ended June 30, 2007. We recognized an $11 million deferred tax expense during the second quarter of 2007. This tax expense was recognized in response to Canadian tax legislation that may apply to a portion of our Canadian activities. In the six months ended June 30, 2008, we recognized a tax benefit related to a reduction in the tax rate applied to flow-through entities in Canada. See Note 11 to our Condensed Consolidated Financial Statements.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Financial Market Volatility

Our marketing activities can generally be described as high volume and low margin activities. Our sales are primarily to purchasers and shippers of crude oil and, to a lesser extent, purchasers of refined products and LPG. These purchasers include refineries, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. Recent turmoil in the financial markets, which escalated late in the first quarter of 2008, resulted in unprecedented actions by the Federal Reserve Bank to provide liquidity to financial institutions. In addition, in the second quarter of 2008, as the values of crude oil and refined products were at historically high levels, there have been liquidity issues at some companies with which we do business. We believe these conditions, combined with significant energy price volatility, have increased the potential credit risks associated with certain financial institutions and trading companies with which we do business. However, we have a rigorous credit review process and closely monitor these conditions in order to make a determination of the amount, if any, 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. Although we believe that our credit risk review procedures and related reserves are adequate, further disruptions in the financial markets and significant energy price volatility that adversely affects our counterparties may have a material adverse effect on our financial condition, results of operations or cash flows.

Crude Oil Prices

As has been publicly reported, the U.S. Commodity Futures Trading Commission (CFTC) has instituted a nationwide investigation of crude oil pricing. In response to a request from the CFTC, we have provided information regarding, among other things, our storage facilities, our pipeline assets and throughput, and our crude oil trading practices. It is our understanding that similar information requests have also been made to a number of companies other than PAA.

Liquidity and Capital Resources

Liquidity

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At June 30, 2008, we had a working capital deficit of approximately $152 million, approximately $1.2 billion of availability under our committed revolving credit facilities and approximately $0.8 billion of availability under our uncommitted hedged inventory facility. Our working capital decreased approximately $96 million in the first six months of 2008. Usage of our credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash Flow from Operations

For a discussion of the primary drivers of cash flow from our operations and the impact of varying market conditions, see Liquidity and Capital Resources *Cash Flow from Operations* under Item 7 of our 2007 Annual Report on Form 10-K.

Our cash flow provided by operating activities in the first six months of 2008 was approximately $576 million, resulting from cash generated by our recurring operations and our primary drivers. Our operating activities were also positively impacted by (i) an increase in prepayments from our counterparties and (ii) our NYMEX margin activities. Our cash flow provided by operating activities was approximately $273 million in the first six months of 2007. This reflects cash generated by our recurring operations, offset by changes in certain working capital items (including an increase in inventory). A significant portion of the increased inventory was purchased and stored due to contango market conditions experienced during the first six months of 2007. This increase in inventory was funded primarily through cash on hand and borrowings under our credit facilities.

Cash Used in or Provided by Equity and Debt Financing Activities

Our financing activities primarily relate to (i) funding acquisitions and internal capital projects and (ii) short-term working capital and hedged inventory borrowings and repayments related to our contango market and LPG activities. These financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

In May 2008, we completed the issuance of 6,900,000 common units for net proceeds of approximately $315 million. The net proceeds include our general partner s proportionate capital contribution and is reflected net of costs associated with the offering. See Note 8 to our Condensed Consolidated Financial Statements.

In April 2008, we completed the issuance of $600 million of 6.5% Senior Notes due May 1, 2018. The senior notes were sold at 99.424% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2008. We used the net proceeds from the offering to repay amounts outstanding under our credit facilities. We may borrow under our credit facilities to fund our capital program, including acquisitions, and for general partnership purposes.

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 $2.0 billion of debt or equity securities. At June 30, 2008, we have approximately $450 million of unissued securities remaining available under this registration statement.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

Our primary uses of cash are for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. See Liquidity and Capital Resources *Capital Expenditures and Distributions Paid to Unitholders and General Partner* under Item 7 of our 2007 Annual Report on Form 10-K.

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. See Note 8 to our Condensed Consolidated Financial Statements for details of distributions paid. Also, see *Cash Distribution Policy* under Item 5 of our 2007 Annual Report on Form 10-K for additional discussion on distribution thresholds.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. See Note 8 to our Condensed Consolidated Financial Statements for details related to the general partner s incentive distributions reduction.

Contingencies

See Note 12 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations

The amounts presented in the table below represent our best estimate as of June 30, 2008 of the amount and timing of the net obligations associated with those contractual obligations that varied significantly since December 31, 2007. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

	Total	2008	2009	2010	2011	2012	2013 and Thereafter
Long-term debt and interest payments (1)	$ 5,915	$ 103	$ 379	$ 198	$ 198	$ 394	$ 4,643
Leases (2)	$ 378	$ 31	$ 50	$ 40	$ 34	$ 29	$ 194
Crude oil, refined products and LPG purchases (3)	$ 12,982	$ 8,467	$ 2,068	$ 1,089	$ 746	$ 612	$

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at June 30, 2008, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for office rent, trucks used in our gathering activities, and rights-of-way obligations.

(3) 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.

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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. At June 30, 2008, we had outstanding letters of credit of approximately $116 million.

Capital Contributions to PAA/Vulcan Gas Storage, LLC

We and Vulcan Gas Storage LLC are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. During the first six months of 2008, we made an additional investment of approximately $40 million in PAA/Vulcan. Such contribution did not result in an increase in our ownership interest. See Note 4 to our Condensed Consolidated Financial Statements.

Distributions

See discussion above under *Capital Expenditures and Distributions Paid to Unitholders and General Partner.*

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

SFAS 157 requires new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. Our assessment of the significance of a particular input to the fair value measurements requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy level. Additional information relating to fair value measurement is discussed in Notes 2 and 10 to our Condensed Consolidated Financial Statements.

For additional discussion regarding our critical accounting policies and estimates, see *Critical Accounting Policies and Estimates* under Item 7 of our 2007 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, intend and forecast, as well as similar expressions and sta 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:

- failure to implement or capitalize on planned internal growth projects;
- 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;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and

transported on our pipeline systems;

- 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

- 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 transportation throughput requirements;

- 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;

- the 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, governmental regulations and interpretations;

- the effects of competition;

- 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;
- future developments and circumstances at the time distributions are declared;
- 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 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 Risk included under Item 7A in our 2007 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 10 to our Condensed 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 June 30, 2008 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a ten percent price decrease are shown in the table below (in millions):

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	Fair Value		Effect of 10% Price Decrease
Crude oil:			
Futures contracts	$ (63)	$	10
Swaps and options contracts	(387)	$	113
LPG and other:			
Futures contracts	31	$	(9)
Swaps and options contracts	281	$	(68)
Total Fair Value	$ (138)		

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 the end of the period covered by this report, 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 second quarter of 2008 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.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under this caption Legal Proceedings in Note 12 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2007 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.

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

None.

Item 5. OTHER INFORMATION

None.

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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	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).
3.4	Amendment No. 3 dated August 16, 2007 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 August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 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 April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 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 May 30, 2008).
3.7	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).
3.8	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).
3.9	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.10	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.11	Certificate of Incorporation of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	Bylaws of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (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, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

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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, as trustee (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, as trustee (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, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
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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, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.10	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.12	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.13	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.14	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.15	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA

	Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee.
4.16	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a 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 Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.17	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed March 9, 2005).
4.18	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.19	Third Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein 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).
4.20	Fourth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 6 1/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.22	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.23	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.24	Exchange and Registration Rights Agreement dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed April 23, 2008).
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.

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SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

By:	PAA GP LLC, its general partner
By:	PLAINS AAP, L.P., its sole member
By:	PLAINS ALL AMERICAN GP LLC, its general partner

Date: August 8, 2008

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

Date: August 8, 2008

By: /s/ PHIL KRAMER
Phil Kramer, *Executive Vice President and Chief Financial Officer (Principal Financial Officer)*

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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	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).
3.4	Amendment No. 3 dated August 16, 2007 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 August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 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 April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 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 May 30, 2008).
3.7	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).
3.8	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).
3.9	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.10	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.11	Certificate of Incorporation of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
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