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

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

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

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

Indicate by check mark whether the registrant is 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 November 4, 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)

	September 30, 2008 (unaudited)	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 37	$ 24
Trade accounts receivable and other receivables, net	2,911	2,561
Inventory	1,391	972
Other current assets	196	116
Total current assets	4,535	3,673
PROPERTY AND EQUIPMENT	5,705	4,938
Accumulated depreciation	(644)	(519)
	5,061	4,419
OTHER ASSETS		
Pipeline linefill in owned assets	431	284
Inventory in third-party assets	78	74
Investment in unconsolidated entities	254	215
Goodwill	1,242	1,072
Other, net	269	169
Total assets	$ 11,870	$ 9,906
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,138	$ 2,577
Short-term debt	1,349	960
Other current liabilities	255	192
Total current liabilities	4,742	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	257	129
Total long-term liabilities	3,477	2,753
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Common unitholders (122,911,645 and 115,981,676 units outstanding, respectively)	3,566	3,343
General partner	85	81
Total partners' capital	3,651	3,424
Total liabilities and partners' capital	$ 11,870	$ 9,906

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

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

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(unaudited)		(unaudited)	
REVENUES	$ 8,862	$ 5,799	$ 25,118	$ 13,946
COSTS AND EXPENSES				
Crude oil, refined products and LPG purchases and related costs	8,369	5,455	23,929	12,884
Field operating costs	162	134	458	395
General and administrative expenses	39	33	130	128
Depreciation and amortization	49	43	150	135
Total costs and expenses	8,619	5,665	24,667	13,542
OPERATING INCOME	243	134	451	404
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	4	11	12
Interest expense (net of capitalized interest of $4, $4, $14 and $10, respectively)	(52)	(39)	(143)	(121)
Interest income and other income (expense), net	14	2	27	8
Income before tax	209	101	346	303
Current income tax expense	(3)	—	(9)	(1)
Deferred income tax benefit (expense)	—	(3)	2	(14)
NET INCOME	$ 206	$ 98	$ 339	$ 288
NET INCOME-LIMITED PARTNERS	$ 173	$ 77	$ 256	$ 231
NET INCOME-GENERAL PARTNER	$ 33	$ 21	$ 83	$ 57
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.15	$ 0.66	$ 2.14	$ 2.06
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.14	$ 0.66	$ 2.12	$ 2.05
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	123	116	120	112
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	124	117	121	113

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)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 339	$ 288
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	150	135
SFAS 133 mark-to-market adjustment	(72)	15
Inventory valuation adjustment	65	—
Equity compensation expense	27	41
Deferred income tax (benefit) expense	(2)	14
Gain on sale of investment assets	(12)	—
Gain on foreign currency revaluation	(2)	(3)
Equity earnings in unconsolidated entities, net of distributions	(4)	(11)
Other	(7)	(2)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(338)	(288)
Inventory	(521)	410
Accounts payable and other current liabilities	619	368
Due to related parties	(3)	2
Net cash provided by operating activities	239	969
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 4)	(662)	(69)

Additions to property, equipment and other	(446)	(402)
Investment in unconsolidated entities	(35)	(9)
Cash paid for linefill in assets owned	(8)	(18)
Proceeds from sales of assets	36	14
Net cash used in investing activities	(1,115)	(484)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on revolving credit facility	259	(126)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	111	(417)
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)	(308)	(272)
Distributions paid to general partner (Note 8)	(84)	(58)
Other financing activities	(4)	(1)
Net cash provided by (used in) financing activities	886	(491)
Effect of translation adjustment on cash	3	8
Net increase (decrease) in cash and cash equivalents	13	2
Cash and cash equivalents, beginning of period	24	11
Cash and cash equivalents, end of period	$ 37	$ 13
Cash paid for interest, net of amounts capitalized	$ 143	$ 146
Cash paid for income taxes	$ 8	$ 3

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		General Partner	Partners' Capital
	Units	Amount	Amount	Amount
		(unaudited)		
Balance at December 31, 2007	116	$ 3,343	$ 81	$ 3,424
Net income		256	83	339
Issuance of common units	7	309	6	315
Issuance of common units under Long Term Incentive Plans ("LTIP")	—	1	—	1
Distributions	—	(308)	(84)	(392)
Class B Units of Plains AAP, L.P.	—	14	—	14
Other comprehensive loss	—	(49)	(1)	(50)
Balance at September 30, 2008	123	$ 3,566	$ 85	$ 3,651

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(unaudited)		(unaudited)	
Net income	$ 206	$ 98	$ 339	$ 288
Other comprehensive income/(loss)	(4)	43	(50)	88
Comprehensive income	$ 202	$ 141	$ 289	$ 376

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

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2007	$ 4	$ 176	$ 180

Reclassification adjustments for settled contracts	12	—	12
Changes in fair value of outstanding hedge positions	35	—	35
Currency translation adjustment	—	(97)	(97)
Total period activity	47	(97)	(50)
Balance at September 30, 2008	$ 51	$ 79	$ 130

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. and its 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 nine months ended September 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 unit ("EPU") 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 EPU data presented will be adjusted retrospectively to conform with the provisions of EITF 03-6-1. We will adopt EITF 03-6-1 on January 1, 2009. Adoption will not impact our distributions to limited partners, financial position, results of operations or cash flows.

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,*&# 148; and other generally accepted accounting principles. 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 will adopt the FSP on January 1, 2009. 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 account ed 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 having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines EPU 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 will adopt EITF 07-04 on January 1, 2009. Adoption will impact the net income available to limited partners used in our computation of EPU but will not impact our distributions to limited partners, financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurements*" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. 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, producers, 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.

The U.S. and world financial markets are extremely volatile, the economy has weakened, and many well-known and previously sound financial institutions are experiencing significant difficulties. In addition, during the first half of 2008 the values of crude oil and refined products reached historically high levels, but recently energy prices have dropped to levels seen last year. This volatility in the financial markets combined with the significant energy price volatility have caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business. Recently, we have seen significant actions taken by the U.S. government in an attempt to provide liquidity and stability to financial institutions and the financial markets.

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 September 30, 2008 and December 31, 2007, we had approximately $73 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 September 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):

Cash payment to sellers	$	660
Assumption of Rainbow debt (at estimated fair value)		26
Estimated transaction costs		2
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):

Property, plant and equipment	$	425
Pipeline linefill in owned assets		143
Intangible assets		52
Goodwill		185
Future income tax liability		(102)
Assumption of working capital and other long-term assets and liabilities, including cash [(1)]		(15)
Total	$	688

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

Investment in Unconsolidated Entities

During the three months ended September 30, 2008, no contribution was made to PAA/Vulcan Gas Storage, LLC; however, for the nine months ended September 30, 2008, we contributed $35 million. These contributions did not result in an increase in our ownership interest. During the three months and nine months ended September 30, 2008, we received distributions of $1 million and $7 million, respectively, from our unconsolidated entities.

Note 5—Inventory and Linefill

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

	September 30, 2008			December 31, 2007		
	Barrels	Dollars	Dollars/ Barrel (1)	Barrels	Dollars	Dollars/ Barrel (1)
Inventory						
Crude oil	6,690	$ 697	$ 104.19	7,365	$ 592	$ 80.38
LPG	10,145	678	$ 66.83	6,480	363	$ 56.02
Refined products	93	10	$ 107.53	133	11	$ 82.71
Parts and supplies	N/A	6	N/A	N/A	6	N/A
Inventory subtotal	16,928	1,391		13,978	972	
Inventory in third-party assets						
Crude oil	850	62	$ 72.94	986	64	$ 64.91
LPG	253	16	$ 63.24	175	10	$ 57.14
Inventory in third-party assets subtotal	1,103	78		1,161	74	
Pipeline linefill in owned assets						
Crude oil	8,905	429	$ 48.18	7,734	282	$ 36.46
LPG	49	2	$ 40.82	43	2	$ 46.51
Pipeline linefill in owned assets subtotal	8,954	431		7,777	284	
Total	26,985	$ 1,900		22,916	$ 1,330	

(1) The prices listed represent a weighted average associated with various grades and qualities of crude oil, LPG and refined products and, accordingly, are not comparable metrics with published benchmarks for such products.

The inventory balances at September 30, 2008 include an inventory valuation adjustment, which resulted in a loss of approximately $65 million, related to certain crude oil and LPG inventories that were revalued to market prices as of September 30, 2008.

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Note 6—Debt

Debt as of September 30, 2008 and December 31, 2007 consisted of the following (in millions):

	September 30, 2008	December 31, 2007
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 4.1% and 5.3% at September 30, 2008 and December 31, 2007, respectively	$ 586	$ 476
Working capital borrowings, bearing interest at a rate of 4.0% and 5.5% at September 30, 2008 and December 31, 2007, respectively (1)	762	482
Other	1	2
Total short-term debt	1,349	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	$ 4,569	$ 3,584

(1) At September 30, 2008 and December 31, 2007, we have classified $762 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. NYMEX is part of CME Group Inc.

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%. A registration statement relating to the exchange offer for the senior notes was filed and declared effective in September 2008. The exchange offer is scheduled to expire and close in November 2008.

In August 2009, our $175 million 4.75% senior notes will mature. However, since we have the ability and intent to refinance those notes, they are classified as long-term debt within our balance sheet.

Credit Facility

At September 30, 2008, we had approximately $0.6 billion of availability under our $1.2 billion uncommitted hedged inventory facility, which was set to mature in November 2008. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. Our utilization under this facility over the last 15 months has averaged approximately $456 million per month.

In light of the current uncertainty in the financial markets, recognition of the recent reduction in oil prices and actions we have taken to reduce our potential working capital requirements, on November 6, we replaced this uncommitted facility with a $525 million committed hedged inventory facility. The new facility's committed amount may be increased to $1.2 billion, subject to obtaining additional commitments from lenders. Initial proceeds from the new committed facility were used to re-finance the outstanding balance of the previous uncommitted facility and subsequent proceeds will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable, and will be repaid from the proceeds of the sale of the financed inventory. The new facility will mature on an annual basis beginning in November 2009 and, except for increased pricing, bears similar terms to the previous facility.

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 September 30, 2008 and December 31, 2007, we had outstanding letters of credit of approximately $73 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 nine months ended September 30, 2008 and 2007 (amounts in millions, except per unit data):

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	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 206	$ 98	$ 339	$ 288
Less: General partner's incentive distribution paid	(30)	(20)	(78)	(52)
Subtotal	176	78	261	236
Less: General partner 2% ownership	(3)	(1)	(5)	(5)
Net income available to limited partners	173	77	256	231
Less: Pro forma EITF 03-06 additional general partner's distribution	(31)	—	—	—
Net income available for limited partners under EITF 03-06	$ 142	$ 77	$ 256	$ 231
Denominator:				
Basic weighted average number of limited partner units outstanding	123	116	120	112
Effect of dilutive securities:				
Weighted average LTIP units [(1)]	1	1	1	1
Diluted weighted average number of limited partner units outstanding	124	117	121	113
Basic net income per limited partner unit	$ 1.15	$ 0.66	$ 2.14	$ 2.06
Diluted net income per limited partner unit	$ 1.14	$ 0.66	$ 2.12	$ 2.05

(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 nine months ended September 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. 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 third quarter of 2008 and 2007 and distributions declared and paid in the nine months ended September 30, 2008 and 2007, net of reductions to the general partner's incentive distributions (in millions, except per unit amounts):

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		Distributions Paid				Distributions per limited partner unit
			General Partner			
Date Declared	Date Paid or To Be Paid	Common Units	Incentive	2%	Total	
October 22, 2008	November 14, 2008 (1)	$ 110	$ 28	$ 2	$ 140	$ 0.8925
July 14, 2008	August 14, 2008	$ 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
October 18, 2007	November 14, 2007	$ 98	$ 21	$ 2	$ 121	$ 0.8400
July 19, 2007	August 14, 2007	$ 96	$ 20	$ 2	$ 118	$ 0.8300
April 17, 2007	May 15, 2007	$ 88	$ 17	$ 2	$ 107	$ 0.8125
January 16, 2007	February 14, 2007	$ 88	$ 15	$ 2	$ 105	$ 0.8000

(1) Payable to unitholders of record on November 4, 2008, for the period July 1, 2008 through September 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 November 2008, the aggregate remaining incentive distribution reductions related to these acquisitions will be approximately $38 million.

Note 9—Equity Compensation Plans

Long-Term Incentive Plans

For discussion of our LTIP awards, see Note 10 to our Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K. At September 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	—	—	0.1	0.8	0.4
1.3(3)	$3.50 - $4.00	—	—	0.8	0.2	0.3
3.8(4) (5)		—	0.6	1.5	1.0	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 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):

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	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2007	3.6	$ 37.73
Granted	0.4	$ 33.77
Vested	(0.1)	$ 32.44
Cancelled or forfeited	(0.1)	$ 34.92
Outstanding at September 30, 2008	3.8	$ 37.50

Our accrued liability at September 30, 2008 related to all outstanding LTIP awards and DERs is approximately $57 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 approximately $51 million.

Class B Units of Plains AAP, L.P.

At September 30, 2008, 154,000 Class B units were outstanding and 46,000 Class B units were reserved for future grants. The total grant date fair value of the Class B units outstanding at September 30, 2008 was approximately $34 million, of which approximately $3 million and $14 million was recognized as expense during the three months and nine months ended September 30, 2008, respectively. In August 2008, 21,000 Class B units were earned upon the payment of our second quarter distribution of $0.8875 per unit and an additional 17,500 will be earned 180 days after such payment. Although the entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding, the intent of the Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners' Capital in our Condensed Consolidated Financial Statements.

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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Equity compensation expense	$ 3	$ 1	$ 27	$ 41
LTIP unit settled vestings	$ —	$ 1	$ 1	$ 18
LTIP cash settled vestings	$ —	$ —	$ 2	$ 16
DER cash payments	$ 1	$ 1	$ 3	$ 3

Based on the September 30, 2008 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $51 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 $39.62 at September 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)	$ 7
2009	23
2010	13
2011	6
2012	2
Total	$ 51

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

(2) Includes equity compensation plan fair value amortization for the remaining three 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 (part of CME Group Inc.), the ICE and over-the-counter ("OTC"), including commodity swap and option contracts entered into with financial institutions and other energy companies. We use derivatives as an effective element of our risk management strategy and do so to eliminate or mitigate risk inherent in our business.

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):

	For the Three Months Ended September 30, 2008			For the Three Months Ended September 30, 2007		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging [1]	$ 164	$ (172)	$ (8)	$ (14)	$ 38	$ 24
Controlled trading program	—	—	—	—	—	—
Interest rate risk hedging	—	—	—	2	—	2
Currency exchange rate risk hedging	(1)	—	(1)	(1)	4	3
Total	$ 163	$ (172)	$ (9)	$ (13)	$ 42	$ 29

	For the Nine Months Ended September 30, 2008			For the Nine Months Ended September 30, 2007		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging [1]	$ 74	$ 81	$ 155	$ (19)	$ 121	$ 102
Controlled trading program	—	—	—	—	1	1
Interest rate risk hedging	—	—	—	2	(1)	1
Currency exchange rate risk hedging	(2)	7	5	3	4	7
Total	$ 72	$ 88	$ 160	$ (14)	$ 125	$ 111

(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 and 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 September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Derivatives that are not designated for hedge accounting [1]	$ 164	$ (14)	$ 72	$ (13)
Ineffective portion of cash flow hedges	(1)	1	—	(1)
Total	$ 163	$ (13)	$ 72	$ (14)

(1) These derivatives that do not qualify for hedge accounting consist of derivatives that are an effective element of our risk management strategy but we did not elect to receive hedge accounting treatment due to various factors including that the positions have historically been immaterial and the required documentation was considered extensive and burdensome. 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):

	September 30, 2008	December 31, 2007
Other current assets	$ 169	$ 56
Other long-term assets	84	26
Other current liabilities	(118)	(97)
Other long-term liabilities and deferred credits	(51)	(22)
Other	—	1
Net asset (liability)	$ 84	$ (36)

The net asset 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):

	September 30, 2008			December 31, 2007		
	Net Asset / (Liability)	Earnings	AOCI	Net Asset / (Liability)	Earnings	AOCI
Commodity price risk hedging	$ 75	$ 27	$ 48	$ (38)	$ (48)	$ 10
Controlled trading program	—	—	—	—	—	—

Interest rate risk hedging [1]	2	2	—	3	3	—
Currency exchange rate risk hedging	7	(3)	10	(1)	—	(1)
	$ 84	$ 26	$ 58	$ (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 $58 million and $9 million of unrealized gains deferred to AOCI for open derivative positions as of September 30, 2008 and as of December 31, 2007, respectively, AOCI also includes deferred losses of approximately $7 million and $5 million as of September 30, 2008 and December 31, 2007, respectively. These deferred losses relate to terminated interest rate hedges 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 gain 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 Canadian dollar ("CAD") denominated intercompany interest receivables. Of the total net gain deferred in AOCI at September 30, 2008, a net gain of approximately $24 million will be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 84% is expected to be reclassified 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 nine months ended September 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 were approximately $6 million and $33 million as of September 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 September 30, 2008 and December 31, 2007 and reduced the amount of our cash required to maintain our initial margin requirements.

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

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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 September 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.

	Fair Value as of September 30, 2008 (in millions)			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:				
Commodity derivatives	$ 170	$ 4	$ 67	$ 241
Interest rate derivatives	—	—	2	2
Foreign currency derivatives	—	—	10	10
Total assets at fair value	$ 170	$ 4	$ 79	$ 253
Liabilities:				
Commodity derivatives	$ (103)	$ —	$ (63)	$ (166)
Foreign currency derivatives	—	—	(3)	(3)
Total liabilities at fair value	$ (103)	$ —	$ (66)	$ (169)
Net asset/(liability) at fair value	$ 67	$ 4	$ 13	$ 84

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. The fair value of our level 3 commodity derivatives, interest rate derivatives and foreign currency derivatives includes adjustments for credit risk. We measure credit risk by deriving a probability of default from market observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of our counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. Fair value adjustments related to our credit risk resulted in a gain of $2 million during the three month period ended September 30, 2008. Fair value adjustments related to counterparty credit risk resulted in a deferred loss of $2 million in AOCI during the three month period ended September 30, 2008. 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.

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):

Beginning Balance at July 1, 2008 and January 1, 2008, respectively	$	(56)	$	(21)
Realized and unrealized gains (losses):				
Included in earnings (1)		36		(45)
Included in other comprehensive income		7		5
Purchases, issuances, sales and settlements		26		74
Transfers into or out of level 3 (2)		—		—
Ending Balance at September 30, 2008	$	13	$	13
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of September 30, 2008 (3)	$	62	$	34

(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 September 30, 2008 and 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.

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.

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. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

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 the pipeline 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 alleged 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. On October 15, 2008 this criminal action (all four counts) was dismissed with prejudice and PPS was not subjected to any fine or penalty.

In September 2008, PPS was served by the State of California with a civil complaint in connection with this release, in the Los Angeles Superior Court Case No. BC398627, alleging violations of the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, violations of two sections of the California Water Code for the unlawful discharge of waste into state waters without a permit, and violations of the Public Nuisance Code alleging that discharge of petroleum into waters of the state had created a public nuisance. This case was settled in October 2008. Pursuant to the terms of the settlement agreement, PPS paid no fine or penalty, but made civil settlement payments to various agencies of the State of California in the total amount of approximately $1.1 million. PPS has submitted these payments to its insurance carrier for reimbursement.

United States of America v. Pacific Pipeline Systems, LLC. In September 2008, the EPA filed a civil complaint against PPS in connection with the March 2005 release described above. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV08-

5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. The EPA and DOJ have discretion to 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 may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We will defend against these charges. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty or fine that might be imposed by the EPA and DOJ, and intend to pursue discussions with the EPA and DOJ regarding such defenses and mitigating circumstances and factors. Although 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 on behalf of the EPA to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE (and other petroleum product) 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 contend that Exxon and GATX are primarily responsible for the majority of the remediation costs. 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 are vigorously defending 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. We are, for instance, in the process of discussing with the Bay Area Air Quality Management District the settlement of certain historical air quality issues at our facilities acquired in the merger.

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 merger, 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 September 30, 2008, our reserve for environmental liabilities totaled approximately $46 million, of which approximately $13 million is classified as short-term and $33 million is classified as long-term. At September 30, 2008, we have recorded receivables totaling approximately $5 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.

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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 period indicated (in millions):

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	Transportation [1]	Facilities	Marketing [1]	Total
Three Months Ended September 30, 2008				
Revenues:				
External Customers	$ 147	$ 39	$ 8,676	$ 8,862
Intersegment [2]	95	30	—	125
Total revenues of reportable segments	$ 242	$ 69	$ 8,676	$ 8,987
Equity earnings of unconsolidated entities	$ 1	$ 3	$ —	$ 4
Segment profit [3] [4] [5]	$ 119	$ 39	$ 138	$ 296
SFAS 133 gain [3]	$ —	$ —	$ 163	$ 163
Maintenance capital	$ 13	$ 5	$ 1	$ 19
Three Months Ended September 30, 2007				
Revenues:				
External Customers	$ 107	$ 31	$ 5,661	$ 5,799
Intersegment [2]	91	23	7	121
Total revenues of reportable segments	$ 198	$ 54	$ 5,668	$ 5,920
Equity earnings of unconsolidated entities	$ 2	$ 2	$ —	$ 4
Segment profit [3] [4] [5]	$ 91	$ 29	$ 61	$ 181
SFAS 133 loss [3]	$ —	$ —	$ (15)	$ (15)
Maintenance capital	$ 9	$ —	$ 1	$ 10

	Transportation [1]	Facilities	Marketing [1]	Total
Nine Months Ended September 30, 2008				
Revenues:				
External Customers	$ 416	$ 109	$ 24,593	$ 25,118
Intersegment [2]	264	85	1	350
Total revenues of reportable segments	$ 680	$ 194	$ 24,594	$ 25,468
Equity earnings of unconsolidated entities	$ 4	$ 7	$ —	$ 11
Segment profit [3] [4] [5]	$ 315	$ 107	$ 190	$ 612
SFAS 133 gain [3]	$ —	$ —	$ 72	$ 72
Maintenance capital	$ 38	$ 15	$ 3	$ 56
Nine Months Ended September 30, 2007				
Revenues:				
External Customers	$ 317	$ 87	$ 13,542	$ 13,946
Intersegment [2]	254	66	23	343
Total revenues of reportable segments	$ 571	$ 153	$ 13,565	$ 14,289
Equity earnings of unconsolidated entities	$ 3	$ 9	$ —	$ 12
Segment profit [3] [4] [5]	$ 244	$ 80	$ 227	$ 551
SFAS 133 loss [3]	$ —	$ —	$ (17)	$ (17)
Maintenance capital	$ 22	$ 6	$ 4	$ 32

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(1) At September 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, rates similar to those charged to third parties or rates that we believe approximate market rates. 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 gain within the marketing segment for the three and nine months ended September 30, 2008 excludes a gain of less than $1 million and a loss of less than $1 million, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The SFAS 133 charge for both the three- and nine- month periods ended September 30, 2007 includes a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

(4) Marketing segment profit includes interest expense on contango inventory purchases of approximately $6 million and $15 million for the three months ended September 30, 2008 and 2007, respectively, and approximately $10 million and $38 million for the nine months ended September 30, 2008 and 2007, respectively.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Segment profit	$ 296	$ 181	$ 612	$ 551
Depreciation and amortization	(49)	(43)	(150)	(135)
Interest expense	(52)	(39)	(143)	(121)
Interest income and other income / (expense), net	14	2	27	8
Income tax expense	(3)	(3)	(7)	(15)
Net income	$ 206	$ 98	$ 339	$ 288

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 September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,909	$ 4,704	$ 107	$ (3,185)	$ 4,535
Property plant and equipment, net	—	4,427	634	—	5,061
Investment in unconsolidated entities	4,315	1,064	—	(5,125)	254
Other assets	23	1,680	317	—	2,020
Total assets	$ 7,247	$ 11,875	$ 1,058	$ (8,310)	$ 11,870
LIABILITIES AND PARTNERS’ CAPITAL					
Total current liabilities	$ 378	$ 7,490	$ 59	$ (3,185)	$ 4,742
Long-term debt	3,218	2	—	—	3,220
Other long-term liabilities	—	256	1	—	257
Total liabilities	3,596	7,748	60	(3,185)	8,219
Partners’ Capital	3,651	4,127	998	(5,125)	3,651
Total liabilities and partners’ capital	$ 7,247	$ 11,875	$ 1,058	$ (8,310)	$ 11,870

	Condensed Consolidating Balance Sheet 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 September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$ —	$ 467	$ 26	$ —	$ 493
Field operating costs	—	(151)	(11)	—	(162)
General and administrative expenses	—	(37)	(2)	—	(39)
Depreciation and amortization	—	(44)	(5)	—	(49)
Operating income (loss)	—	235	8	—	243
Equity earnings in unconsolidated entities	258	10	—	(264)	4
Interest expense	(52)	—	—	—	(52)
Interest and other income (expense), net	—	13	1	—	14
Income tax expense	—	(3)	—	—	(3)
Net income (loss)	$ 206	$ 255	$ 9	$ (264)	$ 206

	Condensed Consolidating Statement of Operations Three Months Ended September 30, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$ —	$ 312	$ 32	$ —	$ 344
Field operating costs	—	(125)	(9)	—	(134)
General and administrative expenses	—	(31)	(2)	—	(33)
Depreciation and amortization	—	(37)	(6)	—	(43)
Operating income (loss)	—	119	15	—	134
Equity earnings in unconsolidated entities	135	17	—	(148)	4
Interest expense	(39)	—	—	—	(39)
Interest and other income (expense), net	2	—	—	—	2
Income tax expense	—	(3)	—	—	(3)
Net income (loss)	$ 98	$ 133	$ 15	$ (148)	$ 98

(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 Statement of Operations Nine Months Ended September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$ —	$ 1,103	$ 86	$ —	$ 1,189
Field operating costs	—	(426)	(32)	—	(458)

General and administrative expenses	—	(121)	(9)	—	(130)
Depreciation and amortization	(2)	(133)	(15)	—	(150)
Operating income (loss)	(2)	423	30	—	451
Equity earnings in unconsolidated entities	483	34	—	(506)	11
Interest expense	(143)	—	—	—	(143)
Interest and other income (expense), net	1	25	1	—	27
Income tax expense	—	(7)	—	—	(7)
Net income (loss)	$ 339	$ 475	$ 31	$ (506)	$ 339

	Condensed Consolidating Statement of Operations Nine Months Ended September 30, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 971	$ 91	$ —	$ 1,062
Field operating costs	—	(367)	(28)	—	(395)
General and administrative expenses	—	(127)	(1)	—	(128)
Depreciation and amortization	(2)	(118)	(15)	—	(135)
Operating income (loss)	(2)	359	47	—	404
Equity earnings in unconsolidated entities	407	51	—	(446)	12
Interest expense	(120)	(1)	—	—	(121)
Interest and other income (expense), net	3	5	—	—	8
Income tax expense	—	(15)	—	—	(15)
Net income (loss)	$ 288	$ 399	$ 47	$ (446)	$ 288

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

	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 339	$ 475	$ 31	$ (506)	$ 339
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	2	133	15	—	150
SFAS 133 mark-to-market adjustment	—	(72)	—	—	(72)
Inventory valuation adjustment	—	65	—	—	65
Equity compensation expense	—	27	—	—	27
Gain on sale of investment asset	—	(12)	—	—	(12)
Gain on foreign currency revaluation	—	(2)	—	—	(2)
Equity earnings in unconsolidated entities, net of distributions	(478)	(32)	—	506	(4)
Deferred income tax benefit	—	(2)	—	—	(2)
Other	—	(7)	—	—	(7)
Changes in assets and liabilities, net of acquisitions	(307)	92	(28)	—	(243)
Net cash provided by (used in) operating activities	(444)	665	18	—	239
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(662)	—	—	(662)
Additions to property and equipment		(428)	(18)	—	(446)
Investment in unconsolidated entities	(35)	—	—	—	(35)
Cash paid for linefill in assets owned	—	(8)	—	—	(8)
Proceeds from sales of assets	—	36	—	—	36
Net cash used in investing activities	(35)	(1,062)	(18)	—	(1,115)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	—	259	—	—	259
Net repayments on short-term letter of credit and hedged inventory facility	—	111	—	—	111
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	(392)	—	—	—	(392)
Other financing activities	(4)	—	—	—	(4)

Net cash provided by financing activities	516	370	—	—	886
Effect of translation adjustment on cash	—	3	—	—	3
Net increase (decrease) in cash and cash equivalents	37	(24)	—	—	13
Cash and cash equivalents, beginning of period	1	23	—	—	24
Cash and cash equivalents, end of period	$ 38	$ (1)	$ —	$ —	$ 37

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	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 288	$ 399	$ 47	$ (446)	$ 288
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	2	118	15	—	135
SFAS 133 mark-to-market adjustment	(2)	17	—	—	15
Equity compensation expense	—	41	—	—	41
Equity earnings in unconsolidated entities, net of distributions	(407)	(50)	—	446	(11)
Deferred income tax expense	—	14	—	—	14
Other	1	(6)	—	—	(5)
Changes in assets and liabilities, net of acquisitions	76	454	(38)	—	492
Net cash provided by operating activities	(42)	987	24	—	969
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquistions	—	(69)	—	—	(69)
Additions to property and equipment	—	(378)	(24)	—	(402)
Investment in unconsolidated entities	(9)	—	—	—	(9)
Cash paid for linefill in assets owned	—	(18)	—	—	(18)
Proceeds from sales of assets	—	14	—	—	14
Net cash used in investing activities	(9)	(451)	(24)	—	(484)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings/(repayments) on revolving credit facility	—	(126)	—	—	(126)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	—	(417)	—	—	(417)
Net proceeds from the issuance of common units	383	—	—	—	383
Distributions paid to common unitholders and general partner	(330)	—	—	—	(330)
Other financing activities	—	(1)	—	—	(1)
Net cash provided by (used in) financing activities	53	(544)	—	—	(491)
Effect of translation adjustment on cash	—	8	—	—	8
Net increase in cash and cash equivalents	1	1	—	—	2
Cash and cash equivalents, beginning of period	2	9	—	—	11
Cash and cash equivalents, end of period	$ 3	$ 10	$ —	$ —	$ 13

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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 — Third Quarter and First Nine Months of 2008 and 2007 (in millions, except per unit data)

	Three Months Ended September 30,		Three Months Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Nine Months Favorable/ (Unfavorable) Variance	
	2008	2007	$	%	2008	2007	$	%
Transportation segment profit	$ 119	$ 91	$ 28	31%	$ 315	$ 244	$ 71	29%
Facilities segment profit	39	29	10	34%	107	80	27	34%

Marketing segment profit	138	61	77	126%	190	227	(37)	(16)%
Segment profit	296	181	115	64%	612	551	61	11%
Depreciation and amortization	(49)	(43)	(6)	(14)%	(150)	(135)	(15)	(11)%
Interest expense	(52)	(39)	(13)	(33)%	(143)	(121)	(22)	(18)%
Interest income and other income (expense), net	14	2	12	600%	27	8	19	238%
Income tax expense	(3)	(3)	—	—	(7)	(15)	8	53%
Net income	$ 206	$ 98	$ 108	110%	$ 339	$ 288	$ 51	18%
Earnings per basic limited partner unit	$ 1.15	$ 0.66	$ 0.49	74%	$ 2.14	$ 2.06	$ 0.08	4%
Earnings per diluted limited partner unit	$ 1.14	$ 0.66	$ 0.48	73%	$ 2.12	$ 2.05	$ 0.07	3%
Basic weighted average units outstanding	123	116	7	6%	120	112	8	7%
Diluted weighted average units outstanding	124	117	7	6%	121	113	8	7%

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

- Five 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 and expansion activities;

- Marketing segment profit for 2008 returned to base-line levels compared to 2007, which benefited from more favorable market conditions;

- A gain of approximately $72 million related to the mark-to-market impact for open derivative instruments (compared to a loss of approximately $15 million for the first nine months of 2007). The mark-to-market gain during the third quarter and first nine months of 2008 is primarily the result of the significant decrease in crude oil prices that occurred during the third quarter of 2008;

- The third quarter of 2008 includes an inventory valuation adjustment, which resulted in a loss of approximately $65 million, related to certain crude oil and LPG inventories which were revalued to market prices as of September 30, 2008. Included in our mark-to-market adjustment is a gain on related financial derivatives, which are economic hedges, that substantially offsets this loss;

- Decreased earnings and increased expenses totaling an estimated $10 million to $15 million due to impacts of Hurricane Gustav and Hurricane Ike, both of which came through the Gulf Coast area during the third quarter of 2008;

- A gain of approximately $12 million resulting from the sale of our shares in NYMEX Holdings, Inc., which merged with CME Group Inc. during the third quarter of 2008;

- Equity compensation plan expense of $27 million compared to approximately $38 million for the prior period. The decreased expense is primarily the result of the decrease in unit price for the first nine months of 2008 compared to the increase in unit price for the first nine 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 for

most of the first nine months of 2007; and

- The issuance during the second quarter of 2008 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.

Acquisitions and Internal Growth Projects

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Acquisition capital	$ 688	$ 69
Investment in unconsolidated entities [(1)]	35	9
Internal growth projects	379	392
Maintenance capital	56	32
	$ 1,158	$ 502

(1) During the nine months ended September 30, 2008, we contributed $35 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	$ 54
Paulsboro tankage	30
Fort Laramie tank expansion	22
St. James phase III (1)	22
Kerrobert mainline connection	20
Rangeland tankage and connections	14
West Hynes tankage	13
Pier 400 (2)	11
Other projects, including acquisition related expansion projects (3)	284
Total (4)	$ 470

(1) Includes a dock and condensate tanks.

(2) 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.

(3) 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. Such amount also includes expansion capital projects associated with the Rainbow acquisition that are expected to be commenced in 2008.

(4) Approximately $379 million of capital expenditures for expansion projects was incurred in the first nine months of 2008.

We forecasted approximately $75 million in capital expenditures for maintenance projects during calendar year 2008, of which approximately $56 million was incurred in the first nine 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.

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 September 30, 2008	Three Months Ended September 30, 2007	Three Months Favorable (Unfavorable) Variance $	Three Months Favorable (Unfavorable) Variance %	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Nine Months Favorable (Unfavorable) Variance $	Nine Months Favorable (Unfavorable) Variance %
Revenues								
Tariff activities	$ 209	$ 169	$ 40	24%	$ 583	$ 486	$ 97	20%
Trucking	33	29	4	14%	97	85	12	14%
Total transportation revenues	242	198	44	22%	680	571	109	19%
Costs and Expenses								
Trucking costs	(23)	(20)	(3)	(15)%	(68)	(58)	(10)	(17)%
Field operating costs (excluding equity compensation expense)	(86)	(74)	(12)	(16)%	(246)	(213)	(33)	(15)%
Equity compensation income (expense) - operations (2)	1	—	1	N/A	(1)	(5)	4	80%
Segment G&A expenses (excluding equity compensation expense) (3)	(14)	(14)	—	—	(42)	(38)	(4)	(11)%
Equity compensation expense - general and administrative (2)	(2)	(1)	(1)	(100)%	(12)	(16)	4	25%
Equity earnings in unconsolidated entities	1	2	(1)	(50)%	4	3	1	33%
Segment profit	$ 119	$ 91	$ 28	31%	$ 315	$ 244	$ 71	29%
Maintenance capital	$ 13	$ 9	$ 4	44%	$ 38	$ 22	$ 16	73%
Segment profit per barrel	$ 0.44	$ 0.36	$ 0.08	22%	$ 0.39	$ 0.32	$ 0.07	22%

Average Daily Volumes	Three Months Ended September 30,	Three Months Favorable	Nine Months Ended September 30,	Nine Months Favorable

(in thousands of barrels per day) [4]	2008	2007	(Unfavorable) Variance Volumes	%	2008	2007	(Unfavorable) Variance Volumes	%
Tariff activities								
All American	44	46	(2)	(4)%	44	48	(4)	(8)%
Basin	375	397	(22)	(6)%	372	382	(10)	(3)%
Capline	216	230	(14)	(6)%	218	232	(14)	(6)%
Line 63/Line 2000	131	171	(40)	(23)%	151	177	(26)	(15)%
Salt Lake City Area Systems	90	103	(13)	(13)%	94	102	(8)	(8)%
West Texas/New Mexico Area Systems [5]	370	382	(12)	(3)%	367	375	(8)	(2)%
Manito	68	72	(4)	(6)%	70	74	(4)	(5)%
Rainbow	191	—	191	N/A	108	—	108	N/A
Rangeland	54	65	(11)	(17)%	58	64	(6)	(9)%
Refined products	108	110	(2)	(2)%	110	110	—	—
Other	1,234	1,129	105	9%	1,238	1,132	106	9%
Tariff activities total	2,881	2,705	176	7%	2,830	2,696	134	5%
Trucking	101	104	(3)	(3)%	96	107	(11)	(10)%
Transportation total	2,982	2,809	173	6%	2,926	2,803	123	4%

(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

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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.
(5) The volumes for the West Texas/New Mexico Area Systems for the three and nine months ended September 30, 2007 previously included amounts for the Mesa system, which has been reclassified to "Other" for all periods presented.

Transportation segment profit and segment profit per barrel for the three- and nine-month periods ended September 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 nine-month periods ended September 30, 2008 as compared to the same periods ended September 30, 2007. The discussion below presents the significant variances in revenues and average daily volumes between the comparative periods:

- Acquisitions and Expansion Projects – Revenues and volumes for the three and nine months ended September 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 $22 million and $34 million of additional tariff revenues for the three and nine months ended September 30, 2008, and additional volumes of approximately 191 thousand barrels per day and 108 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 higher during the first nine months of 2008 than it was in 2007. As a result, loss allowance revenues increased by approximately $9 million and $29 million for the three and nine months ended September 30, 2008 compared to the three and nine months ended September 30, 2007, respectively.

- Foreign Exchange – Revenues from our Canadian pipeline systems (other than Rainbow, as noted above) increased for the three and nine months ended September 30, 2008, compared to the three and nine months ended September 30, 2007, primarily due to the appreciation of Canadian currency. The average exchange rate for the nine months ended September 30, 2008 was $1.02:1 compared to an average of $1.10:1 for the nine months ended September 30, 2007. The Canadian to US dollar exchange rate for the three month periods ended September 30, 2008 and 2007 were comparable at an average rate of $1.04:1 and $1.05:1, respectively.

- Rate Increases – Rates increased on the majority of our pipeline systems on July 1, 2007 and on July 1, 2008 resulted in increased revenues for the three and nine months ended September 30, 2008 compared to the three and nine months ended September 30, 2007. Rates on these systems are increased through indexing by the FERC, by state and Canadian regulatory agencies and through market-based escalation.

- Hurricane Impact – Decreased earnings of an estimated $3 million to $5 million due to impacts of Hurricane Gustav and Hurricane Ike, both of which came through the Gulf Coast area during the third quarter of 2008.

Field Operating Costs. The 2008 increased costs primarily relate to (i) acquisitions, (ii) utilities costs, which increased due to higher market prices, (iii) payroll and employee benefits, (iv) increased maintenance costs for the first nine months of 2008, (v) additional pipeline inspection and integrity maintenance costs, (vi) foreign currency differences and (vii) costs associated with hurricane repairs.

Equity Compensation Expense. Equity compensation charges decreased in 2008 compared to 2007 primarily as a result of the decrease in unit price for the first nine months of 2008 compared to the increase in unit price for the first nine 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 for most of the first nine months of 2007.

Maintenance Capital. The increase in maintenance capital for the nine months ended September 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 nine months of 2007 was lower than forecast. The increase for the three months ended September 30, 2008 is primarily related to maintenance capital spending specifically on assets acquired in the Rainbow acquisition.

Facilities

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Three Months Favorable (Unfavorable) Variance $	Three Months Favorable (Unfavorable) Variance %	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Nine Months Favorable (Unfavorable) Variance $	Nine Months Favorable (Unfavorable) Variance %
Storage and terminalling revenues (1)	$ 69	$ 54	$ 15	28%	$ 194	$ 153	$ 41	27%
Field operating costs	(27)	(22)	(5)	(23)%	(76)	(62)	(14)	(23)%
Segment G&A expenses (excluding equity compensation expense) (2)	(5)	(5)	—	—	(13)	(15)	2	13%
Equity compensation expense - general and administrative (3)	(1)	—	(1)	N/A	(5)	(5)	—	—
Equity earnings in unconsolidated entities	3	2	1	50%	7	9	(2)	(22)%
Segment profit	$ 39	$ 29	$ 10	34%	$ 107	$ 80	$ 27	34%
Maintenance capital	$ 5	$ —	$ 5	N/A	$ 15	$ 6	$ 9	150%
Segment profit per barrel	$ 0.23	$ 0.19	$ 0.04	21%	$ 0.21	$ 0.19	$ 0.02	11%

Volumes (4)(5)(6)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Three Months Favorable (Unfavorable) Variance Volumes	Three Months Favorable (Unfavorable) Variance %	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Nine Months Favorable (Unfavorable) Variance Volumes	Nine Months Favorable (Unfavorable) Variance %
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	55	47	8	17%	54	44	10	23%
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	21	(4)	(19)%	16	18	(2)	(11)%
Facilities total (average monthly capacity in millions of barrels)	58	50	8	16%	57	47	10	21%

(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) Facilities total is 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 nine-month periods ended September 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 nine months ended September 30, 2008 compared to the three and nine months ended September 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 nine months ended September 30, 2008 and 2007 were impacted by the Bumstead and Tirzah acquisitions. The Bumstead acquisition was completed in the latter portion of the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007 and, in the aggregate, both acquisitions contributed additional revenues of approximately $3 million and $10 million for the three and nine months ended September 2008, respectively, and additional volumes of approximately 2 million barrels and 4 million barrels, respectively.

- Expansion Projects - The Cushing, Martinez and St. James expansion projects also resulted in an increase in revenues and volumes in the third quarter and first nine months of 2008 compared to the third quarter and first nine months of 2007.

Field Operating Costs. Our field operating costs were impacted primarily by the Tirzah and Bumstead acquisitions completed during 2007 and the additional tankage added at Cushing, St. James and Martinez in 2008 and 2007.

Maintenance Capital. The increase in maintenance capital for the nine months ended September 30, 2008 is primarily due to maintenance and upgrades at the Martinez, Dominguez Hills, Alamitos and Cushing terminals.

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Marketing

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

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Three Months Favorable (Unfavorable) Variance $	Three Months Favorable (Unfavorable) Variance %	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Nine Months Favorable (Unfavorable) Variance $	Nine Months Favorable (Unfavorable) Variance %
Revenues [2]	$ 8,676	$ 5,668	$ 3,008	53%	$ 24,594	$ 13,565	$ 11,029	81%
Purchases and related costs [3]	(8,471)	(5,556)	(2,915)	(52)%	(24,211)	(13,169)	(11,042)	(84)%
	205	112	93	83%	383	396	(13)	(3)%
Field operating costs	(50)	(38)	(12)	(32)%	(135)	(115)	(20)	(17)%
Segment G&A expenses (excluding equity compensation expense) [4]	(16)	(13)	(3)	(23)%	(49)	(39)	(10)	(26)%
Equity compensation expense - general and administrative [5]	(1)	—	(1)	N/A	(9)	(15)	6	40%
Segment profit [2]	$ 138	$ 61	$ 77	126%	$ 190	$ 227	$ (37)	(16)%
SFAS 133 mark-to-market gain (loss) [2]	$ 163	$ (15)	$ 178	1,187%	$ 72	$ (17)	$ 89	(524)%
Maintenance capital	$ 1	$ 1	$ —	—	$ 3	$ 4	$ (1)	(25)%
Segment profit per barrel [6]	$ 1.86	$ 0.79	$ 1.07	135%	$ 0.81	$ 0.98	$ (0.17)	(17)%

Average Daily Volumes [7] (in thousands of barrels per day)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Three Months Favorable (Unfavorable) Variance Volumes	Three Months Favorable (Unfavorable) Variance %	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Nine Months Favorable (Unfavorable) Variance Volumes	Nine Months Favorable (Unfavorable) Variance %
Crude oil lease gathering	638	679	(41)	(6)%	663	689	(26)	(4)%
Refined products sales	27	14	13	93%	24	10	14	140%
LPG sales	67	58	9	16%	85	78	7	9%
Waterborne foreign crude imported	77	82	(5)	(6)%	84	76	8	11%
Marketing total	809	833	(24)	(3)%	856	853	3	—

(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 $6 million and $15 million for the three and nine months ended September 30, 2008, respectively, compared to $13 million and $38 million for the three and nine months ended September 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 third quarter and first nine months of 2008 increased compared to the third quarter and first nine months of 2007, primarily due to an increase in the average NYMEX price for crude oil. The NYMEX average price was $118 and $113 for the third quarter and first nine months of 2008, respectively, compared to $75 and $66 for the third quarter and first nine months of 2007, respectively.

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

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- Market conditions for our crude oil gathering and marketing activities were not as favorable in the first nine months of 2008 as they were in the first nine months of 2007. Generally we consider the market to be favorable and are able to optimize and enhance the margins of our gathering and marketing activities when there is a high level of volatility in the market combined with favorable basis differentials and a steep contango or backwardated market structure. There was volatility in the outright price of crude oil during both periods as the NYMEX benchmark price of crude oil ranged from approximately $86 to $147 per barrel during the first nine months of 2008 and from approximately $50 to $84 per barrel for the comparable period in 2007. However, that volatility did not lead to as favorable market conditions for the 2008 period as compared to the 2007 period. For further discussion related to contango and backwardated market structures and the respective impacts that they have on our marketing segment profit, see "Analysis of Operating Segments – *Marketing*" under Item 7 of our 2007 Annual Report on Form 10-K.

- Results from our LPG operations were lower in the third quarter and first nine months of 2008 as compared to the respective periods of 2007. Our LPG operations operate on an April to March storage season and the timing of recognizing earnings over that season may vary from year to year based on the sales price of contracts presented for delivery and the average costing of inventory. The first nine month period of 2007 benefited from a strong first quarter that included profits from the end of the 2006 – 2007 storage season. In addition, a significant portion of the profits from our 2008 – 2009 storage season are expected to be recognized in the fourth quarter of 2008 and the first quarter of 2009.

- Revenues for the third quarter of 2008 include a mark-to-market gain under SFAS 133 of approximately $163 million compared to a loss of approximately $15 million for the third quarter of 2007. Revenues for the first nine months of 2008 include a SFAS 133 gain of approximately $72 million compared to a loss of approximately $17 million for the first nine months of 2007. We utilize risk management strategies to hedge anticipated commodity sales and our inventory that effectively enable us to lock in future sales prices and therefore reduce the commodity price risk associated with these anticipated sales. When market prices for commodities decrease below our respective hedged prices we recognize mark-to-market gains on the respective derivatives. The mark-to-market gain during the third quarter and first nine months of 2008 is primarily the result of the significant decrease in crude oil and LPG prices that occurred during the third quarter of 2008. See above for discussion of crude oil volatility. The gain was primarily related to risk management strategies for which we did not elect to receive hedge accounting treatment due to various factors including that the positions have historically been immaterial and the required documentation was considered extensive and burdensome. 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.

- Purchases and related costs for the third quarter of 2008 include an inventory valuation adjustment, which resulted in a loss of approximately $65 million, related to certain crude oil and LPG inventories which were revalued to market prices as of September 30, 2008. Included in our mark-to-market adjustment is a gain on related financial derivatives, which are economic hedges, that substantially offsets this loss.

- The third quarter of 2008 was also negatively impacted by an estimated $7 million to $10 million resulting from reduced volumes and other impacts of Hurricane Gustav and Hurricane Ike.

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

- Equity compensation charges decreased in 2008 compared to 2007 primarily as a result of the decrease in unit price for the first nine months of 2008 compared to the increase in unit price for the first nine 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 for most of the first nine months of 2007.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense for the three and nine months ended September 30, 2008 increased $6 million and $15 million, respectively. Such an increase is primarily a result of an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Also, the three and nine month comparisons are impacted by a $3 million gain on sale of non-core assets in the third quarter of 2008, which reduced depreciation and amortization.

Interest Expense. Interest expense increased $13 million and $22 million for the third quarter and first nine months of 2008 in comparison to the third quarter and first nine months of 2007. The increase primarily resulted from the issuance of $600 million senior notes completed in April 2008.

Interest Income and Other Income (Expense), Net. Interest income and other income (expense), net, increased $12 million and $19 million for the third quarter and first nine months of 2008 in comparison to the third quarter and first nine months of 2007. The increase primarily resulted from (i) a gain of $12 million resulting from the sale of our shares in NYMEX Holdings, Inc. which merged with CME Group Inc. during the third quarter of 2008 and (ii) a gain of $11 million on the forward currency exchange hedge and commodity price risk hedge that we entered into in connection with 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 $8 million for the nine months ended September 30, 2008 in comparison to the nine months ended September 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 applies to a portion of our Canadian activities. In the nine months ended September 30, 2008, we recognized a tax benefit of approximately $3 million related to a reduction in the tax rate applied to flow-through entities in Canada. Income tax expense for the third quarter ended September 30, 2008 is comparable to the same period in 2007.

Outlook

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

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions regarding potential acquisitions of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets that, if acquired, could have a material effect on our financial condition and results of operations. We also have expanded our efforts to prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities. Although we expect the acquisitions we make to be accretive in the long term, we can give no assurance that our current or future acquisition efforts will be successful, that any such acquisition will be completed on terms considered favorable to us or that our expectations will ultimately be realized. In addition, due to the adverse conditions within the financial markets, our access to capital to fund large acquisitions today could prove to be challenging and expensive. Accordingly, we will be selective in our acquisition efforts, focusing on strategic assets and transactions that involve modest financing risk. Also, see Item 1A. "Risk Factors" in our 2007 Annual Report on Form 10-K.

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, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The U.S. and world financial markets are extremely volatile, the economy has weakened, and many well-known and previously sound financial institutions are experiencing significant difficulties. In addition, during the first half of 2008 the values of crude oil and refined products reached historically high levels, but recently the energy prices have dropped to levels seen last year. This volatility in the financial markets combined with the significant energy price volatility have caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business. Recently, we have seen significant actions taken by the U.S. government in an attempt to provide liquidity and stability to financial institutions and the financial markets.

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. 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. We are also responding to a CFTC subpoena regarding trading activities in September 2008, and particularly September 22, a day on which crude oil futures trading on the NYMEX experienced unprecedented volatility.

Liquidity and Capital Resources

Liquidity

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At November 3, 2008 we had approximately $0.6 billion of availability under our committed revolving credit facilities and approximately $0.8 billion of availability under our uncommitted hedged inventory facility. See “Credit Facilities and Long-term Debt” below.

We believe that we have and will continue to have the ability to access these credit facilities which we use to meet our short-term cash needs. At September 30, 2008, we had a working capital deficit of approximately $207 million as compared to $56 million at December 31, 2007.

We believe that our financial position is strong and we have sufficient liquidity; however, further disruptions in the financial markets and significant energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. See Item 1A. “Risk Factors” in our 2007 Annual Report on Form 10-K.

Accordingly, we have taken a number of proactive and preemptive steps to maintain our financial strength and flexibility and the ability to generate baseline cash flow, including:

- We have increased the amount of storage capacity leased to third parties by leasing storage capacity on certain newly constructed tanks and certain tanks previously reserved for our proprietary use, which has increased our fee-based business activities while also reducing our potential working capital requirements.

- We have pre-funded or contemporaneously funded acquisitions and our capital expansion programs in order to maintain a strong balance sheet and high levels of liquidity. As a result, we are targeting to execute our capital plans through 2009 without reliance on the financial markets for incremental debt or equity capital.

- We have reduced our preliminary 2009 capital expansion budget to approximately $250 million.

Cash Flow from Operations

As discussed in “Liquidity and Capital Resources – *Cash Flow from Operations*” under Item 7 of our 2007 Annual Report on Form 10-K, our cash flow from operations can be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. Both 2008 and 2007 were impacted by changes in the amount of inventory stored. During 2008 we have increased our inventory levels primarily related to the routine seasonal build of LPG inventory which occurred in the third quarter. This increase in inventory was financed under our credit facilities (see “Credit Facilities and Long-Term Debt” for additional discussion related to LPG inventory and its impact on liquidity) and had a negative impact on our cash flow from operations for the nine months. Conversely, during the first nine months of 2007 we reduced our overall inventory levels as we liquidated inventory that had been stored in the contango market. The proceeds from liquidating the inventory were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

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 September 30, 2008, we have approximately $450 million of unissued securities remaining available under this registration statement. We intend to file a new shelf registration statement before November 30, 2008 that will be intended to cover our needs over the next several years.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We use cash primarily 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. On October 22, 2008, we announced an increase in our quarterly distribution. Due to the unstable and uncertain financial markets, the amount of the increase in the distribution was modest but achieved a year-over-year distribution increase of 6.3%, which is in the middle of our beginning of the year target for distribution growth of 5-8%. We will continue to monitor the financial market conditions as they evolve and it is our intent to maintain an appropriate balance between the near-term benefits of distribution growth and the long-term benefits of retaining excess cash flow during such challenging times for capital formation. 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.

We currently estimate that our capital expansion program for 2009 will approximate $250 million. The vast majority of funding for this capital program will be provided by a combination of cash flow in excess of partnership distributions, proceeds associated with planned reductions in crude oil and LPG inventories and pending asset sales. This will allow us to fund these capital projects without need to access the capital markets for equity or debt.

Credit Facilities and Long-Term Debt

At September 30, 2008, we had approximately $0.8 billion of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilitzed at September 30, 2008, approximately $73 million was associated with outstanding letters of credit and $762 million was borrowed. The majority of these borrowings relate to LPG inventory that is scheduled to be sold over the next six months. As these inventory sales take place, it will further increase our liquidity. This credit facility, among other things, has a maturity date of July 2012, contains no Material Adverse Change language and can be expanded to $2.0 billion, subject to additional lender commitments. In addition this revolving credit facility includes broad participation from 25 financial institutions, with no one institution holding more that 6% or less than 2% of the total facility.

At September 30, 2008, we had approximately $0.6 billion of availability under our $1.2 billion uncommitted hedged inventory facility, which was set to mature in November 2008. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. Our utilization under this facility over the last 15 months has averaged approximately $456 million per month.

In light of the current uncertainty in the financial markets, recognition of the recent reduction in crude oil prices and actions we have taken to reduce our potential working capital requirements, on November 6, we replaced this uncommitted facility with a $525 million committed hedged inventory facility. The new facility's committed amount may be increased to $1.2 billion, subject to obtaining additional commitments from lenders. Initial proceeds from the new committed facility were used to re-finance the outstanding balance of the previous uncommitted facility and subsequent proceeds will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable, and will be repaid from the proceeds of the sale of the financed inventory. The new facility will mature on an annual basis beginning in November 2009 and, except for increased pricing, bears similar terms to the previous facility.

We also have several issues of senior debt outstanding that total $3.2 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037. Approximately $175 million of these senior notes are due in August 2009. We plan to refinance these notes with a new issuance of senior unsecured notes, if debt capital market conditions improve. However, if the capital market conditions do not improve, we have sufficient availability under our committed revolving credit facility to repay the notes. See Note 6 to our Condensed Consolidated Financial Statements. Usage of our credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Contingencies

See Note 12 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations

The amounts presented in the table below represent our estimate as of September 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)	$ 5,863	$ 52	$ 378	$ 198	$ 198	$ 394	$ 4,643
Leases (2)	375	16	53	42	36	31	197
Crude oil, refined products and LPG purchases (3)	8,556	5,221	1,486	738	592	519	—

(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 September 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.

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 September 30, 2008, we had outstanding letters of credit of approximately $73 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 nine months of 2008, we made an additional investment of approximately $35 million in PAA/Vulcan Gas Storage, LLC. 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 statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

· failure to implement or capitalize on planned internal growth projects;

· 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;

- the success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- 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 ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the successful integration and future performance of acquired assets and 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 September 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):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 74	$ (16)
Swaps and options contracts	(73)	$ 98

LPG and other:		
Futures contracts	(4)	$ (6)
Swaps and options contracts	78	$ (53)
Total Fair Value	$ 75	

Currency Exchange Risk

Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments may include forward exchange contracts, swaps and options. The fair value of these instruments is an unrealized gain of $7 million as of September 30, 2008. A ten percent decrease in the exchange rate (Canadian dollars to US dollars) would result in an increase of approximately $15 million to the fair value of our foreign currency derivatives.

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 third 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

Issuer Repurchases of Equity Securities:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Party of Publicly Announced Plans or Programs	Maximum Number (or approximate dollar value) of Units that May Yet be Purchased Under the Plans or Programs
July 1, 2008 – July 31, 2008	—	N/A	N/A	N/A
August 1, 2008 – August 31, 2008 (1)	8,750	$ 45.04	N/A	N/A
September 1, 2008 – September 30, 2008	—	N/A	N/A	N/A
Total	**8,750**			

(1) In August 2008, we purchased 8,750 common units from our general partner for an average price of $45.04 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our Long-Term Incentive Plans.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	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).

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).
4.6	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, 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 (incorporated by

		reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
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).
†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: November 7, 2008

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

Date: November 7, 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).
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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).

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4.6	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, 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 (incorporated by

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reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).

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).
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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).
†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.

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

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

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 7, 2008

/s/ GREG L. ARMSTRONG

Greg L. Armstrong

Chief Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phil Kramer, certify that:

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

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 7, 2008

/s/ PHIL KRAMER

Phil Kramer
Chief Financial Officer

EXHIBIT 32.1

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

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

(i) the accompanying report on Form 10-Q for the period ended September 30, 2008 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

/s/ GREG L. ARMSTRONG
Name: Greg L. Armstrong
Date: November 7, 2008

EXHIBIT 32.2

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

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

(i) the accompanying report on Form 10-Q for the period ended September 30, 2008 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

/s/ PHIL KRAMER
Name: Phil Kramer
Date: November 7, 2008