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 March 31, 2009
OR	
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**76-0582150** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas (Address of principal executive offices)	**77002** (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 May 1, 2009, there were outstanding 128,661,645 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)

	March 31, 2009 (unaudited)	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 7	$ 11
Trade accounts receivable and other receivables, net	1,218	1,525
Inventory	688	801
Other current assets	100	259
Total current assets	2,013	2,596
PROPERTY AND EQUIPMENT	5,794	5,727
Accumulated depreciation	(711)	(668)
	5,083	5,059
OTHER ASSETS		
Pipeline linefill in owned assets	418	425
Long-term inventory	128	139
Investment in unconsolidated entities	250	257
Goodwill	1,201	1,210
Other, net	292	346
Total assets	$ 9,385	$ 10,032
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,484	$ 1,507
Short-term debt	594	1,027
Other current liabilities	133	426
Total current liabilities	2,211	2,960
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	1	40
Senior notes, net of unamortized net discount of $6 and $6, respectively	3,219	3,219
Other long-term liabilities and deferred credits	214	261
Total long-term liabilities	3,434	3,520
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

PARTNERS CAPITAL				
Common unitholders (128,661,645 and 122,911,645 units outstanding, respectively)		3,592		3,469
General partner		86		83
Total partners capital excluding noncontrolling interest		3,678		3,552
Noncontrolling interest		62		
Total partners capital		3,740		3,552
Total liabilities and partners capital	$	9,385	$	10,032

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended March 31, 2009		2008	
	(unaudited)			
REVENUES				
Crude oil, refined products and LPG sales and related revenues	$	3,132	$	7,037
Pipeline tariff activities, trucking and related revenues		123		125
Storage, terminalling, processing and related revenues		47		33
Total revenues		3,302		7,195
COSTS AND EXPENSES				
Crude oil, refined products and LPG purchases and related costs		2,790		6,836
Field operating costs		152		144
General and administrative expenses		46		40
Depreciation and amortization		58		48
Total costs and expenses		3,046		7,068
OPERATING INCOME		256		127
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities		3		2
Interest expense (net of capitalized interest of $3 and $6, respectively)		(51)		(42)
Interest income and other income (expense), net		4		3
INCOME BEFORE TAX		212		90
Current income tax expense		(2)		(1)
Deferred income tax benefit		1		3
NET INCOME	$	211	$	92
NET INCOME-LIMITED PARTNERS	$	180	$	67
NET INCOME-GENERAL PARTNER	$	31	$	25
BASIC NET INCOME PER LIMITED PARTNER UNIT	$	1.42	$	0.56
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	1.41	$	0.56
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		124		116
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		125		117

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three Months Ended March 31, 2009	2008
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 211	$ 92
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	58	48
Equity compensation expense	11	6
Deferred gains on settled hedges, net	9	
Other	(4)	(3)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other assets	420	(229)
Inventory	121	181
Accounts payable and other liabilities	(348)	414
Net cash provided by operating activities	478	509
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to property, equipment and other	(116)	(149)
Investment in unconsolidated entities	(2)	(13)
Cash received for sale of noncontrolling interest in a subsidiary (Note 7)	26	
Proceeds from the sale of assets and other	4	10
Net cash used in investing activities	(88)	(152)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on revolving credit facilities	(544)	(181)
Net borrowings on short-term letter of credit and hedged inventory facility	78	(62)
Net proceeds from the issuance of common units	210	
Distributions paid to common unitholders (Note 7)	(110)	(99)
Distributions paid to general partner (Note 7)	(30)	(25)
Net cash used in financing activities	(396)	(367)
Effect of translation adjustment on cash	2	3
Net decrease in cash and cash equivalents	(4)	(7)
Cash and cash equivalents, beginning of period	11	24
Cash and cash equivalents, end of period	$ 7	$ 17
Cash paid for interest, net of amounts capitalized	$ 48	$ 53
Cash paid for income taxes	$ 4	$

The accompanying notes are an integral part of these unaudited 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 Excluding Noncontrolling Interest	Noncontrolling Interest	Partners Capital
	Units	Amount				
			(unaudited)			
Balance at December 31, 2008	123	$ 3,469	$ 83	$ 3,552	$	$ 3,552
Sale of noncontrolling interest in a subsidiary		(36)		(36)	62	26
Net income		180	31	211		211
Issuance of common units	6	206	4	210		210
Distributions		(110)	(30)	(140)		(140)
Class B Units of Plains AAP, L.P.		1		1		1
Other comprehensive loss		(118)	(2)	(120)		(120)
Balance at March 31, 2009	**129**	**$ 3,592**	**$ 86**	**$ 3,678**	**$ 62**	**$ 3,740**

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(unaudited)	
Net income	$ 211	$ 92
Other comprehensive loss	(120)	(65)
Comprehensive income	$ 91	$ 27

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance at December 31, 2008	$ 161	$ (86)	$	$ 75
Reclassification adjustments	(100)			(100)
Changes in fair value of outstanding hedge positions	16			16
Deferred gains on settled hedges, net	9			9

Currency translation adjustment				(37)				(37)
Proportionate share of our unconsolidated entities other comprehensive loss						(8)		(8)
Total period activity		(75)		(37)		(8)		(120)
Balance at March 31, 2009	$	86	$	(123)	$	(8)	$	(45)

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

As used in this Form 10-Q, the terms Partnership, Plains, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. a subsidiaries, unless the context indicates otherwise. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC.

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2008 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 condensed balance sheet data as of December 31, 2008 was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America. The results of operations for the three months ended March 31, 2009 should not be taken as indicative of the results to be expected for the full year.

Note 2 Recent Accounting Pronouncements

Standards Adopted as of January 1, 2009

In November 2008, the Emerging Issues Task Force (EITF) issued Issue No. 08-06, *Equity Method Investment Accounting Considerations* (EITF 08-06). EITF 08-06 addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related to equity method investments. We have adopted EITF 08-06 as of January 1, 2009. Adoption did not have any material impact on our 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 SFAS 142. The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141 (revised 2007), *Business Combinations*, and other generally accepted accounting principles. We have adopted the FSP as of January 1, 2009. Adoption did not have any material impact on 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, *Earnings Per Share* 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 earnings per unit for each class of common units and participating securities according to participation rights in undistributed earnings. We have adopted EITF 07-04 as of January 1, 2009. The guidance in this Issue has been applied retrospectively for all financial statement periods presented. Adoption impacted the net income available to limited partners used in our computation of earnings per unit, but did not impact our net income, distributions to limited partners, financial position, results of operations or cash flows. See Note 6 for additional disclosure.

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Note 3 Trade Accounts Receivable

At March 31, 2009 and December 31, 2008, we had received approximately $89 million and $66 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At March 31, 2009 and December 31, 2008, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $7 million and $5 million at March 31, 2009 and December 31, 2008, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Note 4 Inventory and Linefill

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

	March 31, 2009			December 31, 2008		
	Barrels	**Dollars**	**Dollars/ Barrel (1)**	**Barrels**	**Dollars**	**Dollars/ Barrel (1)**
Inventory						
Crude oil	13,100	$ 546	$ 41.68	9,986	$ 421	$ 42.16
LPG	2,903	136	$ 46.85	7,748	370	$ 47.75
Refined products	49	3	$ 61.22	103	5	$ 48.54
Parts and supplies	N/A	3	N/A	N/A	5	N/A
Inventory subtotal	16,052	688		17,837	801	
Pipeline linefill in owned assets						
Crude oil	9,153	416	$ 45.45	9,148	422	$ 46.13
LPG	51	2	$ 39.22	67	3	$ 44.78
Pipeline linefill in owned assets subtotal	9,204	418		9,215	425	
Long-term inventory						
Crude oil	1,767	115	$ 65.08	1,781	121	$ 67.94
LPG	362	13	$ 35.91	363	18	$ 49.59
Long-term inventory subtotal	2,129	128		2,144	139	
Total	27,385	$ 1,234		29,196	$ 1,365	

(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 to published benchmarks for such products.

Note 5 Debt

Debt consists of the following (in millions):

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		March 31, 2009		December 31, 2008
Short-term debt:				
Senior secured hedged inventory facility bearing interest at a rate of 2.3% and 2.3% at March 31, 2009 and December 31, 2008, respectively	$	358	$	280
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% and 1.1% at March 31, 2009 and December 31, 2008, respectively (1)		235		746
Other		1		1
Total short-term debt		594		1,027
Long-term debt:				
Long-term debt under senior unsecured revolving credit facility and other (1)		1		40
Senior notes, net of unamortized net premium and discount (2)		3,219		3,219
Total long-term debt (1) (3)		3,220		3,259
Total debt	$	3,814	$	4,286

(1) At March 31, 2009 and December 31, 2008, we have classified $235 million and $746 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.

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

(3) At March 31, 2009, the aggregate fair value of our fixed-rate senior notes was estimated to be approximately $2,774 million. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end.

In April 2009, we completed the issuance of $350 million of 8.75% Senior Notes due May 1, 2019. The senior notes were sold at 99.994% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2009. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities, which may be reborrowed to fund future investments and for general partnership purposes.

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 March 31, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $47 million and $51 million, respectively.

Note 6 Net Income per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing our limited partners interest in net income by the weighted average number of limited partner units outstanding during the period. Pursuant to EITF 07-04, the limited partners interest in net income is calculated by first reducing net income by the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter (including the incentive distribution interest in excess of the 2% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement. The adoption of EITF 07-04 resulted in a change to our calculation of earnings per unit by using distributions applicable to the period rather than distributions paid in the period (applicable to the previous period). Also, in accordance with EITF 07-04, earnings per unit for prior periods were recast to conform to this revised calculation.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three months ended March 31, 2009 and 2008 (amounts in millions, except per unit data):

	Three Months Ended March 31, 2009	2008
Numerator for basic and diluted earnings per limited partner unit:		
Net income	$ 211	$ 92
Less: General partner s incentive distribution paid (1)	(28)	(23)
Subtotal	183	69
Less: General partner 2% ownership (1)	(3)	(2)
Net income available to limited partners	180	67
Adjustment in accordance with EITF 07-04 (1)	(4)	(2)
Net income available to limited partners in accordance with EITF 07-04	$ 176	$ 65
Denominator:		
Basic weighted average number of limited partner units outstanding	124	116
Effect of dilutive securities:		
Weighted average LTIP units (2)	1	1
Diluted weighted average number of limited partner units outstanding	125	117
Basic net income per limited partner unit	$ 1.42	$ 0.56
Diluted net income per limited partner unit	$ 1.41	$ 0.56

(1) We allocate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). EITF 07-04 requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized within the earnings per unit calculation. We reflect the impact of this difference as the Adjustment in accordance with EITF 07-04.

(2) Our LTIP awards (described in Note 8) 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 7 Partners Capital and Distributions

Noncontrolling Interest in a Subsidiary

During the fourth quarter of 2008, we completed construction on a 93-mile expansion of the Salt Lake City Core Area system from Wahsatch, Utah to Salt Lake City, which has a throughput capacity of approximately 120,000 barrels per day. During February 2009, this pipeline became fully operational. Pursuant to a master formation agreement, we contributed the pipeline with a book value of approximately $246 million to a newly formed joint venture, SLC Pipeline LLC (SLC Pipeline). Holly Energy Partners-Operating, L.P. (HEP) contributed approximately $26 million in cash for a 25% ownership in SLC Pipeline. We own the remaining 75% interest in SLC Pipeline and control the joint venture, and therefore, have consolidated the financial results.

We account for noncontrolling interests in subsidiaries in accordance with SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 160 requires all entities to report noncontrolling interests in subsidiaries (formerly referred to as minority interest) as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a subsidiary that is owned by a third-party.

Upon formation of the SLC Pipeline joint venture and in accordance with SFAS 160, we recognized a loss in partners capital of approximately $36 million. This loss represents the difference between HEP s contribution of cash and the book value of its 25% interest in the net assets of SLC Pipeline. As of March 31, 2009, the noncontrolling interest on the balance sheet consists solely of HEP s interest in the net assets of SLC Pipeline.

Equity Offerings

During the three months ended March 31, 2009, we completed the following equity offering of our common units (in millions, except per unit data):

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Period	Units Issued		Gross Unit Price		Proceeds from Sale		General Partner Contribution		Costs (1)		Net Proceeds
March 2009	5,750,000	$	36.90	$	212	$	4	$	(6)	$	210

(1) The March 2009 offering of common units was an underwritten transaction that required us to pay a gross spread.

No equity offerings were completed during the three months ended March 31, 2008

Distributions

The following table details the distributions related to the first quarter of 2009 and 2008, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

		Distributions Paid									
					General Partner						Distributions
Date Declared	Date Paid or To Be Paid		Common Units		Incentive		2%		Total		per limited partner unit
2009											
April 8, 2009	May 15, 2009 (1)	$	117	$	32	$	2	$	151	$	0.9050
January 14, 2009	February 13, 2009	$	110	$	28	$	2	$	140	$	0.8925
2008											
April 17, 2008	May 15, 2008	$	100	$	25	$	2	$	127	$	0.8650
January 16, 2008	February 14, 2008	$	99	$	23	$	2	$	124	$	0.8500

(1) Payable to unitholders of record on May 5, 2009, for the period January 1, 2009 through March 31, 2009.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distribution. The total reduction in incentive distributions related to these acquisitions is $75 million. Following the distribution in May 2009, the aggregate remaining incentive distribution reductions related to these acquisitions will be approximately $26 million.

Note 8 Equity Compensation Plans

Long-Term Incentive Plans

At March 31, 2009, the following LTIP awards were outstanding (units in millions):

LTIP Units Outstanding	Annualized Distribution per Unit	Estimated Unit Vesting Date 2009	2010	2011	2012
1.3(1)	$3.20	0.6	0.7		
1.4(2)	$3.50 - $4.50			0.9	0.5
1.4(3)	$3.50 - $4.00		0.8	0.2	0.4
4.1(4) (5)		0.6	1.5	1.1	0.9

(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 period.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.50 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.

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(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. 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.

(4) Approximately 2.2 million of our approximately 4.1 million outstanding LTIP awards also include Distribution Equivalent Rights (DERs), of which 1.2 million are currently earned.

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

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

	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2008	3.9	$	36.44
Granted	0.2	$	24.64
Vested			
Cancelled or forfeited			
Outstanding at March 31, 2009	4.1	$	36.62

Our accrued liability at March 31, 2009 related to all outstanding LTIP awards and DERs is approximately $64 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, 2008, the accrued liability was approximately $55 million.

For further discussion of our Long-Term Incentive Plan (LTIP) awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2008 Annual Report on Form 10-K.

Class B Units of Plains AAP, L.P.

At March 31, 2009, 165,500 Class B units were outstanding, of which 38,500 units were earned. A total of 34,500 units were reserved for future grants. During the three months ended March 31, 2009, 11,500 Class B units were issued to certain members of our senior management. These Class B units become earned in increments of 37.5%, 37.5% and 25% 180 days after us achieving annualized distribution levels of $3.75, $4.00 and $4.50, respectively. 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. The total grant date fair value of the 165,500 Class B units outstanding at March 31, 2009 was approximately $34 million of which approximately $1 million was recognized as expense during the three months ended March 31, 2009.

Other Consolidated Equity Compensation Information

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

	Three Months Ended March 31,			
	2009		2008	
Equity compensation expense	$	11	$	6
LTIP unit vestings	$		$	
LTIP cash settled vestings	$		$	1
DER cash payments	$	1	$	1

Based on the March 31, 2009 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $42 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. This estimate is based on the closing market price of our units of $36.76 at March 31,

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2009. Actual amounts may differ materially as a result of a change in the market price of our units 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) (2)	
2009 (3)	$	17
2010		16
2011		6
2012		3
2013		
Total	$	42

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at March 31, 2009.

(2) Includes unamortized fair value associated with Class B units of Plains AAP, L.P.

(3) Includes equity compensation plan fair value amortization for the remaining nine months of 2009.

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Note 9 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and utilize risk management activities to mitigate those risks when we determine there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk, as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our policy is to use derivative instruments only for risk management purposes. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items. A discussion of our derivative activities by risk category follows.

Commodity Price-Risk

Our core business activities contain certain commodity price related risks that we manage in various ways, including the utilization of derivative instruments. Our policy is generally (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we earn, and (iii) not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes. Subsequent to year end 2008, our risk management committee eliminated the 500,000 barrel controlled trading program discussed in our 2008 Form 10-K. In that regard, the committee modified our risk management policies and procedures to better reflect our operating requirements and clarify provisions regarding intra-month activities to maintain a balanced position, which modifications are incorporated into the following discussion. Although we seek to maintain a position that is substantially balanced within our marketing activities, we purchase crude and LPG from thousands of locations and may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions and other uncontrollable events that occur within each month. In connection with our efforts to maintain a balanced position, our personnel are authorized to purchase or sell an aggregate limit of up to 800,000 barrels of crude oil and LPG relative to the volumes originally scheduled for such month, based on interim information. The purpose of these purchases and sales is to manage risk as opposed to establishing a risk position. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

The material commodity related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchase and Sales In the normal course of our marketing operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of March 31, 2009, material net derivative positions related to these activities included:

- An approximate 265,000 barrel per day net long position (total net of 7.9 million barrels) associated with our crude oil activities, which will be unwound ratably during April 2009.

- A short position averaging approximately 20,000 barrels per day (total of 4.7 million barrels) of calendar spread call options for the period May 2009 through December 2009. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

- An average of 4,000 barrels per day (total of 2.4 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are based on a percentage of WTI and continue through 2010.

- Approximately 9,500 barrels per day on average (total of 6.0 million barrels) of crude oil basis differential hedges, which run through 2010.

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Storage Capacity Utilization We own approximately 55 million barrels of crude oil and refined products storage tanks that are not used in our transportation operations. These storage tanks may be leased to third parties or utilized in our own marketing activities, including for the storage of inventory in a contango market. For capacity allocated to our marketing operations we have utilization risk if the market structure is backwardated. As of March 31, 2009, we used derivates to manage the risk of not utilizing approximately 3.0 million barrels per month of storage capacity through 2011. These positions are a combination of calendar spread options and NYMEX futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage At times, we elect to purchase and store crude oil, LPG and refined products inventory in conjunction with our marketing activities. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of March 31, 2009, we had approximately 10 million barrels of hedged inventory.

Pipeline Loss Allowance Oil As is common in the pipeline transportation 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 utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of March 31, 2009, we had entered into derivative positions to manage the risk associated with the anticipated sale of an average of approximately 1,900 barrels per day from April 2009 through December 2012. These derivatives consisted of a net short position of approximately 1.3 million barrels and a net long put option position of approximately 1.3 million barrels. In addition, we were long approximately 1.3 million barrels of call options for the same time period which provide upside price participation.

Diluent Purchases We use diluent in our Canadian crude oil operations and have used derivative instruments to hedge the anticipated forward purchases of diluents. As of March 31, 2009, we had an average of 4,500 barrels per day of natural gasoline/WTI spread positions (approximately 3.7 million barrels) that run through mid 2011.

The derivative instruments we use consist primarily of futures, options and swaps traded on the NYMEX, ICE and in over-the-counter transactions, including commodity swap and option contracts entered into with financial institutions and other energy companies. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into AOCI and recognized in revenues or purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended (SFAS 133). Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded on the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and in certain cases, outstanding debt instruments. The derivative instruments we use consist primarily of interest rate swaps and treasury locks. As of March 31, 2009, AOCI includes deferred losses that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate swaps and treasury locks were cash settled in connection with the issuance and refinancing of debt agreements over the previous five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the forecasted debt instruments.

As of March 31, 2009, our outstanding interest rate derivatives consist of 4 interest rate swaps by which we receive fixed interest payments and pay floating-rate interest payments based on six-month LIBOR plus an average spread of 1.67% on a quarterly basis. The swaps have a combined notional amount of $80 million with a fixed rate of 7.13% and terminate in 2014. Beginning on June 15, 2009, the swaps are subject to a call option whereby our counterparties have the right to call the swaps for a fee of $3 million. Our outstanding interest rate swaps are not designated for hedge accounting. However, the interest rate swaps serve as an economic hedge in the event that market interest rates decline below the fixed interest rate of the underlying debt.

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Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments primarily include forward exchange contracts, swaps and options. As of March 31, 2009, AOCI includes deferred gains that relate to open and settled forward exchange contracts that were designated for hedge accounting. These forward exchange contracts hedge the cash flow variability associated with CAD-denominated interest payments on a CAD denominated intercompany note as a result of changes in the foreign exchange rate. The deferred gains related to these instruments are recognized as other income (expense) concurrent with the underlying CAD-denominated interest payments.

As of March 31, 2009, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative we enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At March 31, 2009, our open foreign exchange derivatives consisted of forward exchange contracts that exchange CAD for U.S. dollars on a net basis as follows (in millions):

	CAD		U.S. Dollars		Average Exchange Rate
2009	$	24	$	18	CAD $1.17 to US $1.00
2010	$	3	$	3	CAD $1.01 to US $1.00
2011	$	3	$	3	CAD $1.01 to US $1.00
2012	$	3	$	3	CAD $1.01 to US $1.00
2013	$	9	$	9	CAD $1.00 to US $1.00

These financial instruments are placed with large, highly rated financial institutions.

Summary of Financial Impact

The majority of our derivative activity relates to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil, LPG, natural gas and refined products, as well as with respect to expected purchases, sales and transportation of these commodities. The instruments that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective, as defined in SFAS 133, in offsetting changes in cash flows of the hedged items, are marked-to-market in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

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A summary of the impact of our derivative activities recognized in earnings for the three-month period ended March 31, 2009 is as follows (in millions, losses designated in parenthesis):

DERIVATIVES IN SFAS 133 CASH FLOW HEDGING RELATIONSHIPS:

	Location of Gain/(Loss)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain or (Loss) Recognized in Income on Derivatives (Ineffective Portion)
Commodity contracts	Crude oil, refined products and LPG sales and related revenues	$ 127	$ (1)
Commodity contracts	Crude oil, refined products and LPG purchases and related costs	(32)	
Foreign exchange contracts	Interest income and other income (expense), net	5	
Total		$ 100	$ (1)

DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS UNDER SFAS 133:

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives
Commodity contracts	Crude oil, refined products and LPG sales and related revenues	$(29)
Commodity contracts	Crude oil, refined products and LPG purchases and related costs	95
Interest rate contracts	Interest income and other income (expense), net	(1)
Foreign exchange contracts	Crude oil, refined products and LPG purchases and related costs	(5)
Total		$60

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The following table summarizes the net derivative assets and liabilities on our consolidated balance sheet as of March 31, 2009 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		**Fair Value**	**Balance Sheet Location**		**Fair Value**
Derivatives designated as hedging instruments under SFAS 133:						
Commodity contracts	Other current assets	$	23	Other current liabilities	$	(26)
	Other long-term assets		66	Other long-term liabilities		
Interest rate contracts	Other current assets			Other current liabilities		
	Other long-term assets			Other long-term liabilities		
Foreign exchange contracts	Other current assets		1	Other current liabilities		
	Other long-term assets		9	Other long-term liabilities		
Total derivatives designated as hedging instruments under SFAS 133		$	99		$	(26)
Derivatives not designated as hedging instruments under SFAS 133:						
Commodity contracts	Other current assets	$	33	Other current liabilities	$	
	Other long-term assets		16	Other long-term liabilities		(28)
Interest rate contracts	Other current assets		1	Other current liabilities		
	Other long-term assets		3	Other long-term liabilities		
Foreign exchange contracts	Other current assets		2	Other current liabilities		(2)
	Other long-term assets			Other long-term liabilities		
Total derivatives not designated as hedging instruments under SFAS 133		$	55		$	(30)
Total derivatives		$	154		$	(56)

As of March 31, 2009, there is a net gain of $86 million deferred in AOCI. 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 CAD-denominated intercompany interest receivables. Of the total net gain deferred in AOCI at March 31, 2009, a net gain of approximately $1 million is expected to be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 96% is expected to be reclassified to earnings prior to 2012 with the remaining deferred gain being reclassed to earnings through 2018. Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the three months ended March 31, 2009, we reclassed a deferred gain of approximately $6 million from AOCI to other income as a result of anticipated hedged transactions that are no longer considered to be probable of occurring. During the three months ended March 31, 2008, no amounts were reclassed from AOCI to earnings as a result of forecasted transactions no longer considered to be probable of occurring.

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Amounts recognized in AOCI during the three months ended March 31, 2009 are as follows (in millions):

	Amount of Gain/(Loss) Recognized in AOCI on Derivatives (Effective Portion)
Commodity contracts	$ (72)
Foreign exchange contracts	(3)
Total	$ (75)

We do not enter into master netting agreements with our derivative counterparties, nor do we 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. The account equity in our brokerage accounts is a combination of our cash balance and the fair value of our open derivatives within our brokerage account. When our account equity is less than our initial margin requirement we are required to post margin. At March 31, 2009, we did not have a broker receivable because the fair value of our open derivatives exceeded our initial margin requirements. Our broker receivable was approximately $81 million as of December 31, 2008. At March 31, 2009 and 2008, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

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 March 31, 2009. 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 March 31, 2009 (in millions)				Fair Value as of December 31, 2008 (in millions)			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Commodity derivatives	$ 78	$ 14	$ 46	$ 138	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives			4	4			5	5
Foreign currency derivatives			12	12			18	18
Total assets at fair value	$ 78	$ 14	$ 62	$ 154	$ 235	$ 9	$ 135	$ 379
Liabilities:								
Commodity derivatives	$ (20)	$	$ (34)	$ (54)	$ (330)	$	$ (56)	$ (386)
Foreign currency derivatives			(2)	(2)			(5)	(5)
Total liabilities at fair value	$ (20)		$ (36)	$ (56)	$ (330)	$	$ (61)	$ (391)
Net asset/(liability) at fair value	$ 58	$ 14	$ 26	$ 98	$ (95)	$ 9	$ 74	$ (12)

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 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

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ultimately be recovered through a bankruptcy proceeding in the event of default. 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, options and swaps. 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 over-the-counter 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):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Balance as of January 1, 2009 and 2008, respectively	$ 74	$ (21)
Realized and unrealized gains (losses):		
Included in earnings	46	(26)
Included in other comprehensive income	(1)	(5)
Purchases, issuances, sales and settlements	(93)	21
Transfers into or out of level 3		
Balance as of March 31, 2009 and 2008, respectively	$ 26	$ (31)
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of March 31, 2009 and 2008, respectively	$ 43	$ (24)

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.

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Note 10 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. Although, we are subject to state income taxes in some states, the impact 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 has historically been treated as a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in June 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, we believe, 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 11 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 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

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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. 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 DOJ and 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 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.

SemCrude Bankruptcy. We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately $62 million. We intend to vigorously defend our contractual and statutory rights.

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.

United States of America 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 September 2008, the EPA filed a civil complaint against PPS, a subsidiary acquired in the Pacific merger, in connection with the Pyramid Lake release. 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

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estimated maximum potential remediation cost ranges up to $10 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 contamination, which occurred prior to PAT s ownership.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in mitigative costs or the imposition of fines and penalties.

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

Environmental

We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to help prevent releases, damages and liabilities incurred due to any such 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. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link 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. See Pipeline Releases above.

At March 31, 2009, our reserve for environmental liabilities totaled approximately $40 million, of which approximately $9 million is classified as short-term and $31 million is classified as long-term. At March 31, 2009, we have recorded receivables totaling approximately $4 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

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

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change

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in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate we will elect to self-insure more of our environmental and wind damage exposures, incorporate higher retention in our insurance arrangements, pay higher premiums or some combination of such actions.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 12 Operating Segments

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

	Transportation		Facilities		Marketing		Total	
Three Months Ended March 31, 2009								
Revenues:								
External Customers	$	123	$	47	$	3,132	$	3,302
Intersegment (1)		102		30		1		133
Total revenues of reportable segments	$	225	$	77	$	3,133	$	3,435
Equity earnings of unconsolidated entities	$	1	$	2	$		$	3
Segment profit(2) (3) (4)	$	112	$	46	$	159	$	317
Maintenance capital	$	14	$	6	$	2	$	22
Three Months Ended March 31, 2008								
Revenues:								
External Customers	$	125	$	33	$	7,037	$	7,195
Intersegment (1)		80		26				106
Total revenues of reportable segments	$	205	$	59	$	7,037	$	7,301
Equity earnings of unconsolidated entities	$	1	$	1	$		$	2
Segment profit(2) (3) (4)	$	89	$	31	$	57	$	177
Maintenance capital	$	14	$	5	$	1	$	20

(1) 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 2008 Annual Report on Form 10-K.

(2) Gains/losses from derivative activities are included in marketing revenues and impact segment profit. The losses within the marketing segment for the three months ended March 31, 2009 and 2009 include gains of approximately $3 million and $2 million, respectively, related to foreign currency and interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

(3) Marketing segment profit includes interest expense on contango inventory purchases of $3 million and $6 million for the

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three months ended March 31, 2009 and 2008, respectively.

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

	For the Three Months Ended March 31, 2009	2008
Segment profit	$ 317	$ 177
Depreciation and amortization	(58)	(48)
Interest expense	(51)	(42)
Interest income and other income (expense), net	4	3
Income tax (expense) benefit	(1)	2
Net income	$ 211	$ 92

Note 13 Supplemental Condensed Consolidating Financial Information

For purposes of this Note 13, Plains All American is referred to as Parent. See Note 13 to our Consolidated Financial Statements included in Part IV of our 2008 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, 2008.

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):

Condensed Consolidating Balance Sheet

	As of March 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,454	$ 2,218	$ 125	$ (2,784)	$ 2,013
Property, plant and equipment, net		4,193	890		5,083
Investment in unconsolidated entities	4,575	1,153		(5,478)	250
Other assets	24	1,699	316		2,039
Total assets	$ 7,053	$ 9,263	$ 1,331	$ (8,262)	$ 9,385
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 95	$ 4,657	$ 243	$ (2,784)	$ 2,211

Long-term debt		3,218		2						3,220
Other long-term liabilities				213		1				214
Total liabilities		3,313		4,872		244		(2,784)		5,645
Partners capital excluding noncontrolling interest		3,678		4,329		1,087		(5,416)		3,678
Noncontrolling interest		62		62				(62)		62
Total partners capital		3,740		4,391		1,087		(5,478)		3,740
Total liabilities and partners capital	$	7,053	$	9,263	$	1,331	$	(8,262)	$	9,385

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Condensed Consolidating Balance Sheet

	As of December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,698	$ 2,789	$ 110	$ (3,001)	$ 2,596
Property, plant and equipment, net		4,410	649		5,059
Investment in unconsolidated entities	4,388	895		(5,026)	257
Other assets	27	1,777	316		2,120
Total assets	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 304	$ 5,411	$ 246	$ (3,001)	$ 2,960
Long-term debt	3,257	2			3,259
Other long-term liabilities		260	1		261
Total liabilities	3,561	5,673	247	(3,001)	6,480
Partners capital	3,552	4,198	828	(5,026)	3,552
Total liabilities and partners capital	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032

Condensed Consolidating Statements of Operations

	Three Months Ended March 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 484	$ 28	$	$ 512
Field operating costs		(143)	(9)		(152)
General and administrative expenses		(44)	(2)		(46)
Depreciation and amortization	(1)	(51)	(6)		(58)
Operating income (loss)	(1)	246	11		256
Equity earnings in unconsolidated entities	265	12		(274)	3
Interest expense	(52)	1			(51)
Interest and other income (expense), net	(1)	5			4
Income tax expense		(1)			(1)
Net income (loss)	$ 211	$ 263	$ 11	$ (274)	$ 211

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	Three Months Ended March 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 329	$ 30	$	$ 359
Field operating costs		(132)	(12)		(144)
General and administrative expenses		(37)	(3)		(40)
Depreciation and amortization	(1)	(43)	(4)		(48)
Operating income (loss)	(1)	117	11		127
Equity earnings in unconsolidated entities	133	11		(142)	2
Interest expense	(43)	1			(42)
Interest income and other income (expense), net	2	1			3
Income tax expense		2			2
Net income (loss)	$ 91	$ 132	$ 11	$ (142)	$ 92

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

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Condensed Consolidating Statements of Cash Flows

	Three Months Ended March 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 211	$ 263	$ 11	$ (274)	$ 211
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	1	51	6		58
Equity compensation expense		11			11
Net cash received for terminated interest rate and foreign currency hedging instruments		9			9
Other	(263)	(15)		274	(4)
Changes in assets and liabilities, net of acquisitions	235	(30)	(12)		193
Net cash provided by operating activities	184	289	5		478
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property, equipment and other		(111)	(5)		(116)
Investment in unconsolidated entities	(2)				(2)
Cash received for noncontrolling interest in connection with formation of a subsidiary		26			26
Proceeds from the sale of assets		4			4
Net cash used in investing activities	(2)	(81)	(5)		(88)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	(252)	(292)			(544)
Net borrowings on short-term letter of credit and hedged inventory facility		78			78
Net proceeds from the issuance of common units	210				210
Distributions paid to common unitholders and general partner	(140)				(140)
Net cash used in financing activities	(182)	(214)			(396)
Effect of translation adjustment on cash		2			2
Net decrease in cash and cash equivalents		(4)			(4)
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 2	$ 5	$	$	$ 7

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Condensed Consolidating Statements of Cash Flows

	Three Months Ended March 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 91	$ 132	$ 11	$ (142)	$ 92
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	1	43	4		48
Equity compensation expense		6			6
Other	(130)	(20)		142	(8)
Changes in assets and liabilities, net of acquisitions	175	160	36		371
Net cash provided by operating activities	137	321	51		509
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property and equipment		(98)	(51)		(149)
Investment in unconsolidated entities	(13)				(13)
Proceeds from sales of assets		10			10
Net cash used in investing activities	(13)	(88)	(51)		(152)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		(181)			(181)
Net repayments on short-term letter of credit and hedged inventory facility		(62)			(62)
Distributions paid to common unitholders and general partner	(124)				(124)
Net cash used in financing activities	(124)	(243)			(367)
Effect of translation adjustment on cash		3			3
Net decrease in cash and cash equivalents		(7)			(7)
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ 1	$ 16	$	$	$ 17

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Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Executive Summary

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 2008 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.

Our discussion and analysis includes the following:

- Overview of Operating Results, Capital Spending and Significant Activities
- Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements

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- Critical Accounting Policies and Estimates

Overview of Operating Results, Capital Spending and Significant Activities

During the first quarter of 2009, our operations provided results that exceeded those experienced during the first quarter of 2008. The increase in first quarter 2009 results were driven primarily by our marketing segment, which benefited from a favorable contango crude oil market structure and favorable LPG margins. Additional key items impacting the first quarter of 2009 include:

- Contributions to earnings from the acquisition of Rainbow Pipe Line Company, Ltd. (Rainbow), which was completed in May 2008 for consideration of approximately $687 million and higher average pipeline tariff rates.

- Equity compensation plan expense of approximately $11 million for the first quarter of 2009 compared to $6 million for the corresponding prior year period. The increased expense is primarily the result of an increase in unit price for the first three months of 2009 compared to a decrease in unit price for the first three months of 2008.

- The issuance of 5,750,000 limited partner units at $36.90 per unit for net proceeds of approximately $210 million.

Internal Growth Projects

The following table summarizes our capital expenditures for acquisitions, investments in unconsolidated entities, internal growth projects and maintenance capital for the periods indicated (in millions):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Investment in unconsolidated entities	$ 2	$ 13
Internal growth projects	79	124
Maintenance capital	22	20
	$ 103	$ 157

Our internal growth projects primarily relate to the construction and expansion of pipeline systems and crude oil storage and terminal facilities. The following table summarizes our more notable projects undertaken in 2009 and the forecasted expenditures for the year (in millions):

Projects		2009
St. James Phase III (1)	$	85
Rangeland tankage and connections		35
Kerrobert pumping project		34
Cushing Phase VII		29
Nipisi storage and truck terminal		20
Patoka Phase II		20
Salt Lake City		14
Pier 400		13
Paulsboro		8
Other projects, including acquisition related expansion projects (2)		92
Total	$	350

(1) Includes a dock and condensate tanks.

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(2) Primarily pipeline connections and upgrades, truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

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 2008 Annual Report on Form 10-K for further discussion on how we evaluate segment performance.

	Three Months Ended March 31,		Favorable/(Unfavorable) Variance	
	2009	**2008**	**$**	**%**
Transportation segment profit	$ 112	$ 89	$ 23	26%
Facilities segment profit	46	31	15	48%
Marketing segment profit	159	57	102	179%
Total segment profit	317	177	140	79%
Depreciation and amortization	(58)	(48)	(10)	(21)%
Interest expense	(51)	(42)	(9)	(21)%
Interest income and other income (expense), net	4	3	1	33%
Income tax benefit (expense)	(1)	2	(3)	(150)%
Net income	$ 211	$ 92	$ 119	129%
Earnings per basic limited partner unit	$ 1.42	$ 0.56	$ 0.86	154%
Earnings per diluted limited partner unit	$ 1.41	$ 0.56	$ 0.85	152%
Basic weighted average units outstanding	124	116	8	7%
Diluted weighted average units outstanding	125	117	8	7%

Transportation Segment

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

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Operating Results (1) **(in millions, except per barrel amounts)**	**Three Months Ended March 31,** **2009**	 **2008**	**Favorable/(Unfavorable) Variance** **$**	 **%**
Revenues				
Tariff activities	$ 201	$ 174	$ 27	16%
Trucking	24	31	(7)	(23)%
Total transportation revenues	225	205	20	10%
Costs and Expenses				
Trucking costs	(16)	(21)	5	24%
Field operating costs (excluding equity compensation expense)	(78)	(79)	1	1%
Equity compensation expense - operations (2)	(1)		(1)	N/A
Segment G&A expenses (excluding equity compensation expense)	(14)	(14)		%
Equity compensation expense - general and administrative (2)	(5)	(3)	(2)	(67)%
Equity earnings in unconsolidated entities	1	1		%
Segment profit	$ 112	$ 89	$ 23	26%
Maintenance capital	$ 14	$ 14	$	%
Segment profit per barrel	$ 0.43	$ 0.36	$ 0.07	19%

Average Daily Volumes **(in thousands of barrels per day) (3)**	**Three Months Ended March 31,** **2009**	 **2008**	**Favorable/(Unfavorable) Variance** **Volumes**	 **%**
Tariff activities				
All American	35	46	(11)	(24)%
Basin	393	363	30	8%
Capline	206	190	16	8%
Line 63/Line 2000	121	162	(41)	(25)%
Salt Lake City Area Systems	104	97	7	7%
West Texas/New Mexico Area Systems (4)	395	350	45	13%
Manito	65	69	(4)	(6)%
Rainbow	195		195	N/A
Rangeland	59	62	(3)	(5)%
Refined products	97	115	(18)	(16)%
Other	1,141	1,191	(50)	(4)%
Tariff activities total	2,811	2,645	166	6%
Trucking	89	97	(8)	(8)%
Transportation segment total	2,900	2,742	158	6%

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

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

(3) 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.

(4) The volumes for the West Texas/New Mexico Area Systems 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 months ended March 31, 2009 were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for the three months ended March 31, 2009 as compared to the three months ended March 31, 2008. The significant variances in revenues and average daily volumes between the comparative periods are discussed below:

• Acquisitions and Expansion Projects Revenues and volumes for the three months ended March 31, 2009 were impacted by the Rainbow acquisition, which occurred in May 2008, and various other systems brought into service

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throughout the year. The Rainbow acquisition contributed approximately $18 million of additional tariff revenues and additional volumes of approximately 195,000 barrels per day for the three months ended March 31, 2009.

- West Texas/New Mexico Area Systems Revenues for the three months ended March 31, 2009 increased by approximately $9 million in comparison to the three months ended March 31, 2008. The increase in revenues is primarily due to the increased tariff rates and volumes compared to the first quarter of 2008.

- Various Other Systems Volumes on other various systems declined; however the volume decrease did not materially impact revenues for the three months ended March 31, 2009 compared to the first three months of 2008.

Field Operating Costs. Field operating costs (excluding equity compensation costs of approximately $1 million and the Rainbow acquisition related costs of approximately $4 million) decreased for the three months ended March 31, 2009 compared to the three months ended March 31, 2008 primarily related to utilities and compliance with API 653 and pipeline integrity testing.

Facilities Segment

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 March 31,** **2009**	**2008**	**Favorable/(Unfavorable) Variance** **$**	**%**
Storage and terminalling revenues (1)	$ 77	$ 59	$ 18	31%
Field operating costs	(27)	(24)	(3)	(13)%
Segment G&A expenses (excluding equity compensation expense)	(4)	(4)		%
Equity compensation expense - general and administrative (2)	(2)	(1)	(1)	(100)%
Equity earnings in unconsolidated entities	2	1	1	100%
Segment profit	$ 46	$ 31	$ 15	48%
Maintenance capital	$ 6	$ 5	$ 1	20%
Segment profit per barrel	$ 0.26	$ 0.19	$ 0.07	37%

Volumes (3)(4)	**Three Months Ended March 31,** **2009**	**2008**	**Favorable/(Unfavorable) Variance** **Volumes**	**%**
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	55	51	4	8%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet (bcf))	17	13	4	31%
	14	15	(1)	(7)%

LPG processing (average throughput in thousands of barrels per day)				
Facilities segment total **(average monthly capacity in millions of barrels)**	58	54	4	7%

(1) Revenues include intersegment amounts.

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

(3) 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.

(4) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG 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 months ended March 31, 2009 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 months ended March 31, 2009 compared to the three months ended March 31, 2008. The significant variances in revenues and average daily volumes between the comparative periods are discussed below:

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- Expansion Projects and Acquisitions - The Paulsboro, Patoka, St. James and Ft. Laramie expansion projects resulted in an increase in revenues of approximately $7 million and volumes of approximately 6 million barrels per month for the first three months of 2009 compared to the first three months of 2008. In addition, revenues and volumes for the three months ended March 31, 2009 were impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008. The San Pedro acquisition contributed approximately $2 million in revenues and volumes of approximately 1 million barrels per month for the three months ended March 31, 2009.

- Rate Increases Revenues for the three months ended March 31, 2009 increased approximately $6 million due to rate increases at various facilities.

Field Operating Costs. Field operating costs (excluding equity compensation charges) have increased in most categories for the three months ended March 31, 2009 in comparison to the three months ended March 31, 2008 primarily related to the expansion projects and acquisitions discussed above.

Marketing Segment

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

	Three Months Ended March 31,		Favorable/(Unfavorable) Variance	
Operating Results (1) **(in millions, except per barrel amounts)**	**2009**	**2008**	**$**	**%**
Revenues	$ 3,133	$ 7,037	$ (3,904)	(55)%
Purchases and related costs (3)	(2,904)	(6,921)	4,017	58%
Field operating costs	(49)	(41)	(8)	(20)%
Segment G&A expenses (excluding equity compensation expense)	(18)	(16)	(2)	(13)%
Equity compensation expense - general and administrative (4)	(3)	(2)	(1)	(50)%
Segment profit (2)	$ 159	$ 57	$ 102	179%
Maintenance capital	$ 2	$ 1	$ 1	100%
Segment profit per barrel (5)	$ 2.04	$ 0.69	$ 1.35	196%

	Three Months Ended March 31,		Favorable/(Unfavorable) Variance	
Average Daily Volumes (6) **(in thousands of barrels per day)**	**2009**	**2008**	**Volumes**	**%**
Crude oil lease gathering purchases	631	680	(49)	(7)%
Refined products sales	36	20	16	80%
LPG sales	144	136	8	6%
Waterborne foreign crude oil imported	58	74	(16)	(22)%
Marketing segment total	869	910	(41)	(5)%

(1) Revenues and costs include intersegment amounts.

(2) Includes net gains/(losses) related to inventory valuation adjustments and derivative activities.

(3) Purchases and related costs include interest expense on hedged inventory purchases of approximately $2 million and $6 million for the three months ended March 31, 2009 and 2008, respectively.

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

(5) Calculated based on crude oil lease gathering purchased volumes, refined products volumes, LPG sales volumes and waterborne foreign crude oil imported volumes.

(6) 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.

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Marketing segment profit and segment profit per barrel for the three months ended March 31, 2009 were impacted by the following:

Revenues and Purchases and Related Costs. The absolute amount of our revenues and purchases decreased in the first quarter of 2009 as compared to the first quarter of 2008, primarily resulting from lower commodity prices in the 2009 period. The NYMEX benchmark price of crude oil ranged from $33 to $55 per barrel and $86 to $112 per barrel during the first quarter of 2009 and 2008, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for the both the purchase and sale, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those purchases and sales will not necessarily have a corresponding increase or decrease. Generally, we expect a base level of earnings from our marketing segment that may be optimized and enhanced when there is a high level of volatility, favorable basis differentials or a steep contango or backwardated market structure.

The positive variance between our net revenues and purchases for the applicable periods was primarily attributable to the favorable contango market structure and higher LPG sales margins.

- *Contango Market Structure* - Earnings in the first quarter of 2009 were favorably impacted by a strong contango market, while the corresponding market conditions during the first quarter of 2008 were slightly backwardated. The market structure for the quarter ranged from $0.70 per barrel to $8.49 per barrel contango and averaged approximately $3.69 per barrel contango. The market structure averaged approximately $0.29 per barrel backwardation for the first quarter of 2008.

- *LPG Marketing* Results from our LPG operations were higher in the first quarter of 2009 as compared to the respective period in 2008. We captured higher sales margins in the first quarter of 2009 primarily due to opportunities created by colder than normal weather. A portion of our LPG profits were the result of higher priced fixed price sales satisfied by purchasing lower priced product in a declining market, which effectively accelerated some of the 2009/2010 winter season s profits into the first quarter of 2009. Adding further to the variance, earnings from our LPG marketing activities were negatively impacted in the first quarter of 2008 as higher profits were recognized earlier in the 2007/2008 season due to increased demand.

In addition, results for our marketing operations were positively impacted by a mark-to-market gain of $26 million on derivatives entered into to manage the price risks associated with the future purchase of diluents used in our Canadian crude oil operations. The net gain was a reversal of a mark-to-market loss recognized in earlier periods.

Volumes. The crude oil lease gathering purchases average daily volumes decreased 49,000 barrels per day in 2009 as compared to 2008, however there was not a material impact to earnings. The decrease in volumes was primarily related to a change in methodology for reporting volumes and due to an ongoing effort to reduce low margin barrels. In addition, waterborne foreign crude oil imported volumes have decreased by approximately 16,000 barrels per day for the three months ended March 31, 2009 compared to the three months ended March 31, 2008 as the foreign barrels were not as competitively priced as domestic barrels.

Field Operating Costs. Field operating costs (excluding equity compensation charges) have increased in several categories for the three months ended March 31, 2009 in comparison to the three months ended March 31, 2008. The 2009 increased costs primarily relate to (i) payroll and benefits, (ii) maintenance costs and (iii) third-party trucking fees.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense for the three months ended March 31, 2009 increased $10 million in comparison to the three months ended March 31, 2008 primarily as a result of an increased amount of depreciable assets resulting from our Rainbow and San Pedro acquisition activities and internal growth projects. Depreciation and amortization expense was also impacted by approximately $3 million related to an impairment of excess equipment.

Interest Expense. Interest expense for the three months ended March 31, 2009 increased $9 million in comparison to the three months ended March 31, 2008. The increase primarily resulted from the issuance of $600 million of senior notes completed during the second quarter of 2008. Additionally, interest capitalized to various internal growth projects was lower for the three months ended March 31, 2009 as compared to the same period in 2008 as a result of completion in subsequent quarters of projects under construction at March 31, 2008. These increases were partially offset by an improvement in variable interest charges under our short-term credit facilities as a result of lower interest rates.

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At March 31, 2009, we had a working capital deficit of approximately $198 million, approximately $1.3 billion of availability under our committed revolving credit facility and approximately $168 million of availability under our committed hedged inventory facility. We are currently in compliance with the covenants contained in our credit agreements and indentures.

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and 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 2008 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources.

Cash Flow from Operations

For a comprehensive discussion of the primary drivers of cash flow from our operations, including the impact of varying market conditions and the timing of settlement of our derivative activities, see Liquidity and Capital Resources Cash Flow from Operations under Item 7 of our 2008 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. During the first quarter of 2009, we decreased the amount of our inventory. The decrease in inventory was primarily related to the sale of LPG inventory resulting from end users increased demand for heating requirements in the winter months. The decrease in LPG inventory was partially offset by an increase in crude oil inventory related to the strong contango market in the first quarter of 2009. These net volumetric decreases were further impacted by lower prices for our inventory purchases during the quarter compared to prior year amounts. The net proceeds received from liquidation of inventory during the quarter were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

Our cash flow provided by operating activities in the first quarter of 2008 was approximately $509 million resulting from cash generated by our recurring operations as well as proceeds from the liquidation of inventory. The decrease in inventory was primarily related to the sale of LPG inventory resulting from end users   increased heating requirements in the winter months.

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Equity and Debt Financing Activities

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

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 up to an aggregate of $2.0 billion of debt or equity securities. After giving effect to our March 2009 equity offering and our April 2009 debt offering, we have $1.4 billion of unissued securities remaining available under this registration statement.

Senior Notes. In April 2009, we completed the issuance of $350 million of 8.75% Senior Notes due May 1, 2019. We used the net proceeds from this offering of approximately $347 million to reduce outstanding borrowings under our credit facilities, which may be reborrowed to fund future investment and for general partnership purposes.

Equity Offerings. In March 2009, we completed the issuance of 5,750,000 common units at $36.90 per unit for net proceeds of approximately $210 million. The net proceeds include our general partner s proportionate capital contribution and is reflected net of costs associated with the offering.

Credit Facilities. During the quarter ended March 31, 2009, we had net repayments on our revolving credit facilities of approximately $544 million. These net repayments resulted primarily from sales of LPG inventory that was liquidated during the quarter. During the same period, we had net borrowings on our hedged inventory facility of approximately $78 million, which was primarily due to the favorable contango market structure. During the quarter ended March 31, 2008, we had net repayments on our revolving credit facilities and hedged inventory facility of approximately $181 million and $62 million, respectively. For further discussion related to our credit facilities and long-term debt, see Liquidity and Capital Resources Credit Facilities and Long-Term Debt under Item 7 of our 2008 Annual Report on Form 10-K.

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. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See Internal Growth Projects above and Internal Growth Projects and Acquisitions under Item 7 of our 2008 Annual Report on Form 10-K for further discussion of such capital expenditures.

Distributions to Unitholders and General Partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. See Note 7 to our Condensed Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash

Distribution Policy under Item 7 of our 2008 Annual Report on Form 10-K for additional discussion of 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 7 to our Condensed Consolidated Financial Statements for details related to the general partner s incentive distribution reduction.

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

Contingencies

See Note 11 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. The amounts presented in the table below includes our best estimate as of March 31, 2009 of the amount and timing of the net obligations associated with those contractual obligations that varied significantly since December 31, 2008. In the case of crude oil and LPG purchases, in the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

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	Total	2009	2010	2011	2012	2013	2014 and Thereafter
Long-term debt and interest payments(1)	$ 5,812	$ 379	$ 198	$ 198	$ 394	$ 431	$ 4,212
Leases(2)	437	50	54	44	38	22	229
Crude oil and LPG purchases(3)	3,689	2,619	547	309	210	4	

(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 March 31, 2009, 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 (i) storage, (ii) rights-of-way, (iii) office rent and (iv) trucks used in our gathering activities.

(3) Amounts are based on estimated volumes and market prices based on average activity during March 2009. 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 March 31, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $47 million and $51 million, respectively.

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 three months of 2009 and 2008, we made additional contributions of approximately $2 million and $13 million, respectively, to PAA/Vulcan Gas Storage, LLC. During the first three months of 2009 and 2008, we received distributions of approximately $2 million and $3 million, respectively, from PAA/Vulcan. Vulcan Gas Storage made the same net contribution as we did during the first three months of 2009 and 2008. Such contributions did not result in any change in ownership interest.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2008 Annual Report on Form 10-K.

Forward-Looking Statements and Associated Risks

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

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

- 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;

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- 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 or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related 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 the amplification of other risks caused by deteriorating financial markets, capital constraints and pervasive liquidity concerns; 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.

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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 2008 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 9 to our 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 March 31, 2009 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	$ 90	$ 15
Swaps and options contracts	184	$ 60
LPG and other:		
Futures contracts	(42)	$ (2)
Swaps, options and other contracts (1)	(148)	$ (30)
Total Fair Value	$ 84	

(1) Amount includes approximately $34 million associated with LPG and natural gas physical contracts not eligible for the normal purchase and sale scope exception under SFAS 133.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

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

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Certifications

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 the caption Litigation in Note 11 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 2008 Annual Report on Form 10-K. Those 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 those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on 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).

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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 3.2 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 3.1 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	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 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 20, 2009).
4.17	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 71/8% 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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).

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4.22	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo 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, 2008).
4.23	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 61/4% 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).
4.24	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).
4.25	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).
12.1	Computation of Ratio of Earnings to Fixed Charges
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

** Management compensatory plan or arrangement

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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: May 8, 2009		
	By:	/s/ GREG L. ARMSTRONG Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*
Date: May 8, 2009		
	By:	/s/ AL SWANSON Al Swanson, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

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EXHIBIT INDEX

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 the Current Report on 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 3.2 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 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.11	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

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4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
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).

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4.16	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 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 20, 2009).
4.17	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 71/8% 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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo 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, 2008).
4.23	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 61/4% 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).
4.24	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).
4.25	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).
12.1	Computation of Ratio of Earnings to Fixed Charges
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

** Management compensatory plan or arrangement