PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 07, 2009
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UNITED STATES SECURITIES AND EXCHANGE

COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 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. xYes oNo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). xYes oNo

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

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

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

At August 4, 2009, there were outstanding 128,938,683 Common Units.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	June 30, 2009	December 31, 2008
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 7	$ 11
Trade accounts receivable and other receivables, net	1,674	1,525
Inventory	995	801
Other current assets	246	259
Total current assets	2,922	2,596
PROPERTY AND EQUIPMENT	6,028	5,727
Accumulated depreciation	(773)	(668)
	5,255	5,059
OTHER ASSETS		
Pipeline linefill in owned assets	429	425
Long-term inventory	127	139
Investment in unconsolidated entities	256	257
Goodwill	1,226	1,210
Other, net	344	346
Total assets	$ 10,559	$ 10,032
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,927	$ 1,507
Short-term debt	938	1,027
Other current liabilities	343	426
Total current liabilities	3,208	2,960
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	4	40
Senior notes, net of unamortized net discount of $6 and $6, respectively	3,394	3,219
Other long-term liabilities and deferred credits	247	261
Total long-term liabilities	3,645	3,520
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

PARTNERS CAPITAL				
Common unitholders (128,938,683 and 122,911,645 units outstanding, respectively)		3,558		3,469
General partner		85		83
Total partners capital excluding noncontrolling interest		3,643		3,552
Noncontrolling interest		63		
Total partners capital		3,706		3,552
Total liabilities and partners capital	$	10,559	$	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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited)		(unaudited)	
REVENUES				
Crude oil, refined products and LPG sales and related revenues	$ 4,099	$ 8,880	$ 7,231	$ 15,917
Pipeline tariff activities, trucking and related revenues	130	144	254	268
Storage, terminalling, processing and related revenues	53	36	100	70
Total revenues	4,282	9,060	7,585	16,255
COSTS AND EXPENSES				
Crude oil, refined products and LPG purchases and related costs	3,829	8,724	6,619	15,560
Field operating costs	160	152	312	297
General and administrative expenses	54	51	100	90
Depreciation and amortization	56	52	114	100
Total costs and expenses	4,099	8,979	7,145	16,047
OPERATING INCOME	183	81	440	208
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	5	4	8	7
Interest expense (net of capitalized interest of $2, $3, $5 and $9, respectively)	(56)	(49)	(107)	(91)
Interest income and other income/(expense), net	2	10	5	12
INCOME BEFORE TAX	134	46	346	136
Current income tax expense		(5)	(2)	(6)
Deferred income tax benefit	2		3	3
NET INCOME	$ 136	$ 41	$ 347	$ 133
NET INCOME-LIMITED PARTNERS	$ 102	$ 16	$ 282	$ 83
NET INCOME-GENERAL PARTNER	$ 34	$ 25	$ 65	$ 50
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.79	$ 0.09	$ 2.20	$ 0.65
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.78	$ 0.09	$ 2.18	$ 0.64
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	129	120	126	118
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	130	121	127	119

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)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 347	$ 133
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	114	100
Equity compensation charge	30	24
Other	(1)	(13)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(162)	(559)
Inventory	(178)	(234)
Accounts payable and other liabilities	137	1,125
Net cash provided by operating activities	287	576
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(56)	(661)
Additions to property, equipment and other	(228)	(301)
Investment in unconsolidated entities	(5)	(40)
Cash received for sale of noncontrolling interest in a subsidiary	26	
Proceeds from the sale of assets and other	10	15
Net cash used in investing activities	(253)	(987)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on revolving credit facility	(459)	(204)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	157	(56)
Net proceeds from the issuance of senior notes (Note 5)	350	597
Net proceeds from the issuance of common units	210	315
Distributions paid to common unitholders (Note 7)	(227)	(199)
Distributions paid to general partner (Note 7)	(64)	(52)
Other financing activities	(5)	(5)
Net cash provided by (used in) financing activities	(38)	396
Effect of translation adjustment on cash		2
Net decrease in cash and cash equivalents	(4)	(13)
Cash and cash equivalents, beginning of period	11	24
Cash and cash equivalents, end of period	$ 7	$ 11
Cash paid for interest, net of amounts capitalized	$ 103	$ 92
Cash paid for income taxes	$ 7	$ 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 Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interest	Noncontrolling Interest	Partners Capital
			(unaudited)			
Balance, December 31, 2008	123	$ 3,469	$ 83	$ 3,552	$	$ 3,552
Sale of noncontrolling interest in a subsidiary		(36)	(1)	(37)	63	26
Net income		282	65	347		347
Issuance of common units	6	206	4	210		210
Issuance of common units under Long Term Incentive Plans (LTIP)		12		12		12
Distributions		(227)	(64)	(291)		(291)
Class B Units of Plains AAP, L.P.		2		2		2
Other comprehensive loss		(150)	(2)	(152)		(152)
Balance, June 30, 2009	129	$ 3,558	$ 85	$ 3,643	$ 63	$ 3,706

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited)		(unaudited)	
Net income	$ 136	$ 41	$ 347	$ 133
Other comprehensive income/(loss)	(32)	20	(152)	(45)
Comprehensive income	$ 104	$ 61	$ 195	$ 88

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Cash Flow Hedging Activities	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2008	$ 161	$ (86)	$	$ 75

Reclassification adjustments		(118)						(118)
Changes in fair value of outstanding hedge positions		(38)						(38)
Deferred losses on settled hedges, net		(47)						(47)
Currency translation adjustment				59				59
Proportionate share of our unconsolidated entities other comprehensive loss						(8)		(8)
Total period activity		(203)		59		(8)		(152)
Balance, June 30, 2009	$	(42)	$	(27)	$	(8)	$	(77)

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 and six months ended June 30, 2009 should not be taken as indicative of the results to be expected for the full year.

Subsequent events have been evaluated through the financial statements issuance date of August 7, 2009 and have been included within the following footnotes where applicable.

Note 2 Recent Accounting Pronouncements

Standards Adopted as of April 1, 2009

In May 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 165, *Subsequent Events* (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of subsequent events or events that occur after the balance sheet date but before financial statements are issued. This standard sets forth (i) the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (ii) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements and (iii) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. This standard was effective for interim or annual periods ending after June 15, 2009; therefore, we have adopted SFAS 165 as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 107-1, *Interim Disclosures about Fair Value of Financial Statements* (FSP No. FAS 107-1). FSP No. FAS 107-1 increases the frequency of fair value disclosures from annual to quarterly in an effort to provide financial statement users with more timely and transparent information about the effects of current market conditions on financial instruments. This is intended to address concerns raised by some financial statement users about the lack of comparability resulting from the use of different measurement attributes for financial instruments. These disclosures are also intended to stimulate more robust discussions about financial instrument valuations between users and reporting entities. We have adopted FSP No. FAS 107-1 as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

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 FASB issued 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 No. 142, *Goodwill and Other Intangible Assets* (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141 (revised 2007), *Business Combinations*, and other generally accepted accounting principles. We have adopted FSP No. FAS 142-3 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*

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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.

Note 3 Trade Accounts Receivable

At June 30, 2009 and December 31, 2008, we had received approximately $147 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 June 30, 2009 and December 31, 2008, substantially all of our net accounts receivable classified as current assets were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $8 million and $5 million at June 30, 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, Linefill and Long-term Inventory

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

	June 30, 2009			December 31, 2008		
	Barrels	**Dollars**	**Dollars/ Barrel (1)**	**Barrels**	**Dollars**	**Dollars/ Barrel (1)**
Inventory						
Crude oil	13,694	$ 774	$ 56.52	9,986	$ 421	$ 42.16
LPG	5,882	216	$ 36.72	7,748	370	$ 47.75
Refined products	40	2	$ 50.00	103	5	$ 48.54
Parts and supplies	N/A	3	N/A	N/A	5	N/A
Inventory subtotal	19,616	995		17,837	801	
Pipeline linefill in owned assets						
Crude oil	9,101	427	$ 46.92	9,148	422	$ 46.13
LPG	51	2	$ 39.22	67	3	$ 44.78
Pipeline linefill in owned assets subtotal	9,152	429		9,215	425	
Long-term inventory						

Crude oil	1,690		115	$	68.05	1,781		121	$	67.94
LPG	342		12	$	35.09	363		18	$	49.59
Long-term inventory subtotal	2,032		127			2,144		139		
Total	30,800	$	1,551			29,196	$	1,365		

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(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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	June 30, 2009	December 31, 2008
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.1% and 2.3% at June 30, 2009 and December 31, 2008, respectively	$ 436	$ 280
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% and 1.1% at June 30, 2009 and December 31, 2008, respectively (1)	325	746
Senior notes, net of unamortized discount (2) (3)	175	
Other	2	1
Total short-term debt	938	1,027
Long-term debt:		
Long-term debt under senior unsecured revolving credit facility and other (1)	4	40
Senior notes, net of unamortized net premium and discount	3,394	3,219
Total long-term debt (1) (3)	3,398	3,259
Total debt	$ 4,336	$ 4,286

(1) At June 30, 2009 and December 31, 2008, we have classified $325 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) Our $175 million 4.75% senior notes will mature on August 15, 2009 (see discussion of the issuance of our $350 million 8.75% senior notes below).

(3) We estimate the aggregate fair value of our fixed-rate senior notes at June 30, 2009 to be approximately $3,550 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 July 2009, we completed the issuance of $500 million of 4.25% Senior Notes due September 1, 2012. The senior notes were sold at 99.802% of face value. Interest payments are due on March 1 and September 1 of each year, beginning on March 1, 2010. We used the net proceeds from this offering to supplement the capital available under our existing hedged inventory facility to fund working capital needs associated with base levels of routine foreign crude oil import and for seasonal LPG inventory requirements. Concurrent with the issuance of these Senior Notes, we entered into interest rate swaps whereby we receive fixed payments at 4.25% and pay three-month LIBOR plus a spread on a notional principal amount of $150 million maturing in two years and an additional $150 million notional principal amount maturing in three years.

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, including repayment of our $175 million 4.75% senior notes that mature in August 2009.

Letters of Credit

In connection with our crude oil marketing, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At June 30, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $51 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

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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 six months ended June 30, 2009 and 2008 (amounts in millions, except per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 136	$ 41	$ 347	$ 133
Less: General partner s incentive distribution paid (1)	(32)	(25)	(60)	(49)
Subtotal	104	16	287	84
Less: General partner 2% ownership (1)	(2)		(5)	(1)
Net income available to limited partners	102	16	282	83
Adjustment in accordance with EITF 07-04 (1)		(5)	(5)	(7)
Net income available to limited partners in accordance with EITF 07-04	$ 102	$ 11	$ 277	$ 76
Denominator:				
Basic weighted average number of limited partner units outstanding	129	120	126	118
Effect of dilutive securities:				
Weighted average LTIP units (2)	1	1	1	1
Diluted weighted average number of limited partner units outstanding	130	121	127	119
Basic net income per limited partner unit	$ 0.79	$ 0.09	$ 2.20	$ 0.65
Diluted net income per limited partner unit	$ 0.78	$ 0.09	$ 2.18	$ 0.64

(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. LTIP awards that are deemed to be dilutive 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

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Equity Offerings

During the six months ended June 30, 2009 and 2008, we completed the following equity offerings of our common units (in millions, except per unit data):

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs (1)	Net Proceeds
2009						
March 2009	5,750,000	$ 36.90	$ 212	$ 4	$ (6)	$ 210
2008						
April 2008	6,900,000	$ 46.31	$ 320	$ 6	$ (11)	$ 315

(1) Costs include the gross spread paid to underwriters in connection with the March 2009 and April 2008 equity offerings of common units.

LTIP Vesting

In May 2009, in connection with the settlement of vested LTIP awards, we issued 277,038 common units at a price of $41.23, for a fair value of approximately $12 million.

Distributions

The following table details the distributions related to the first six months 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						
July 15, 2009	August 14, 2009 (1)	$ 117	$ 32	$ 2	$ 151	$ 0.9050
April 8, 2009	May 15, 2009	$ 117	$ 32	$ 2	$ 151	$ 0.9050
January 14, 2009	February 13, 2009	$ 110	$ 28	$ 2	$ 140	$ 0.8925
2008						
July 14, 2008	August 14, 2008	$ 109	$ 30	$ 2	$ 141	$ 0.8875
April 17, 2008	May 15, 2008	$ 100	$ 25	$ 2	$ 127	$ 0.8650
January 16, 2008	February 14, 2008	$ 99	$ 23	$ 2	$ 124	$ 0.8500

(1) Payable to unitholders of record on August 4, 2009, for the period April 1, 2009 through June 30, 2009.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to these acquisitions is $75 million. Following the distribution in August 2009, the aggregate remaining incentive distribution reductions related to these acquisitions will be approximately $21 million.

Note 8 Equity Compensation Plans

Long-Term Incentive Plans

For discussion of our Long-Term Incentive Plan (LTIP) awards, see Note 10 to our Consolidated Financial Statements included in our 2008 Annual Report on Form 10-K. At June 30, 2009, the following LTIP awards were outstanding (units in millions):

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LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date				
		2009	2010	2011	2012	2013
0.6(1)	$3.20		0.6			
1.4(2)	$3.50 - $4.50			0.8	0.5	0.1
1.5(3)	$3.50 - $4.00		0.9	0.2	0.4	
3.5(4) (5)			1.5	1.0	0.9	0.1

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(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 while the grantee remains employed by us, or the grantee does not meet the employment requirements, these awards will be forfeited. For purposes of this disclosure, the awards are presented above assuming that the distribution levels are attained, that all grantees remain employed by us through the vesting date, and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. 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 1.7 million of our approximately 3.5 million outstanding LTIP awards also include Distribution Equivalent Rights (DERs), of which 1 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, December 31, 2008	3.9	$ 36.44
Granted	0.3	$ 26.56
Vested	(0.6)	$ 34.72
Cancelled or forfeited	(0.1)	$ 38.99
Outstanding, June 30, 2009	3.5	$ 36.68

Our accrued liability at June 30, 2009 related to all outstanding LTIP awards and DERs is approximately $55 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.

Class B Units of Plains AAP, L.P.

At June 30, 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 six months ended June 30, 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. The total grant date fair value of the 165,500 Class B units outstanding at June 30, 2009 was approximately $35 million of which approximately $1 million and $2 million was recognized as expense during the three months and six months ended June 30, 2009, respectively. For further discussion of the Class B units, see Note 10 to our Consolidated Financial Statements included in our 2008 Annual Report on Form 10-K.

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):

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	Three Months Ended June 30,				Six Months Ended June 30,			
	2009		2008		2009		2008	
Equity compensation expense	$	19	$	18	$	30	$	24
LTIP unit settled vestings	$	18	$	1	$	18	$	1
LTIP cash settled vestings	$	7	$	1	$	7	$	2
DER cash payments	$	1	$	1	$	2	$	2

Based on the June 30, 2009 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $44 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 $42.55 at June 30, 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)	$	13
2010		20
2011		8
2012		3
Total	$	44

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at June 30, 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 six months of 2009.

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 that 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 commodity risk management policies and procedures are designed to monitor 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 interest rate and foreign currency risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. 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 Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use 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. Although we seek to maintain a position that is substantially balanced within our marketing activities, we purchase crude oil and LPG from thousands of locations and may experience net unbalanced positions 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 810,000 barrels of crude oil, refined products 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 Purchases 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 June 30, 2009, material net derivative positions related to these activities included:

- An approximate 187,000 barrel per day net long position (total net of 5.6 million barrels) associated with our crude oil activities, which was unwound ratably during July 2009 to match monthly average pricing.

- A net short position averaging approximately 15,900 barrels per day (total of 8.1 million barrels) of calendar spread call options for the period August 2009 through December 2010. 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 approximately 3,500 barrels per day (total of 1.9 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a fixed percentage of WTI and continue through 2010.

- Approximately 16,100 barrels per day on average (total of 8.7 million barrels) of crude oil basis differential hedges, which run through 2010.

Storage Capacity Utilization We own approximately 56 million barrels of crude oil, LPG and refined products storage capacity that is not used in our transportation operations. This storage 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 June 30, 2009, we used derivatives to manage the risk of not utilizing approximately 3 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

June 30, 2009, we had approximately 10 million barrels of inventory hedged with derivatives.

We also purchase foreign cargoes of crude oil. Concurrent with the purchase of foreign cargo inventory, we enter into derivatives to mitigate the price risk associated with the foreign cargo inventory between the time the foreign cargo is purchased and the ultimate sale of the foreign cargo. As of June 30, 2009, we had approximately 4 million barrels of foreign cargo inventory hedged with derivatives.

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 June 30, 2009, we had entered into a net short position consisting of crude oil futures and swaps to manage the risk associated with the anticipated sale of an average of approximately 2,300 barrels per day (total of 2.1 million barrels) from July 2009 through December 2011. In addition, we had a long put option position of approximately 1 million barrels through December 2012 and a net long call option position of approximately 2 million barrels through December 2011, 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 diluent. As of June 30, 2009, we had an average of 4,900 barrels per day of natural gasoline/WTI spread positions (approximately 3.5 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. Over-the-counter transactions include 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 June 30, 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 June 30, 2009, we had one outstanding interest-rate swap by which we receive fixed interest payments and pay floating-rate interest payments based on six-month LIBOR plus a spread of 1.85% on a quarterly basis. The swap has a notional amount of $20 million with a fixed rate of 7.13% and terminates in 2014. The swap is subject to a call option whereby our counterparty has the right to call the swap for approximately $1 million. Our outstanding interest-rate swap is not designated for hedge accounting. However, the interest-rate swap serves as an economic hedge in the event that market interest rates decline below the fixed interest rate of the underlying debt. During June 2009, we received notice from our counterparty of their intention to call the swap. As a result, the swap was called in July 2009 upon our receipt of the termination payment.

Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the U.S. Dollar-to-Canadian Dollar exchange rate. Because a significant portion of our Canadian business is conducted in Canadian Dollars and, at times, a portion of our debt is denominated in Canadian Dollars, 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 June 30, 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 Canadian Dollar-denominated interest payments on a Canadian Dollar-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 Canadian Dollar-denominated interest payments.

As of June 30, 2009, our outstanding foreign currency derivatives also include derivatives used to hedge Canadian Dollar-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a Canadian Dollar-denominated commodity transaction with a U.S. Dollar-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 June 30, 2009, our open foreign exchange derivatives consisted of forward exchange contracts that exchange Canadian Dollars for U.S. Dollars on a net basis as follows (in millions):

	Canadian Dollars	U.S. Dollars	Average Exchange Rate
2009	$ 29	$ 25	CAD $1.15 to US $1.00
2010	$ 31	$ 27	CAD $1.14 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.

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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 anticipated purchases, sales and transportation of these commodities. The majority of our 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 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 recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2009 is as follows (in millions, losses designated in parenthesis):

DERIVATIVES IN SFAS 133 CASH FLOW HEDGING RELATIONSHIPS:

		Three Months Ended June 30, 2009		**Six Months Ended June 30, 2009**	
	Location of Gain/(Loss)	**Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)**	**Amount of Gain/(Loss) Recognized in Income on Derivatives (Ineffective Portion)**	**Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)**	**Amount of Gain/(Loss) Recognized in Income on Derivatives (Ineffective Portion)**
Commodity contracts	Crude oil, refined products and LPG sales and related revenues	$ 17	$ (7)	$ 144	$ (8)
Commodity contracts	Crude oil, refined products and LPG purchases and related costs	1		(31)	
Foreign exchange contracts	Interest income and other income (expense), net			5	
Total		$ 18	$ (7)	$ 118	$ (8)

DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS UNDER SFAS 133:

Location of Gain or (Loss) Recognized in Income on Derivative	**Three Months Ended June 30, 2009 Amount of Gain/(Loss) Recognized in Income on Derivatives**	**Six Months Ended June 30, 2009 Amount of Gain/(Loss) Recognized in Income on Derivatives**

Commodity contracts	Crude oil, refined products and LPG sales and related revenues	$	35	$	6
Commodity contracts	Crude oil, refined products and LPG purchases and related costs		20		115
Interest rate contracts	Interest income and other income (expense), net				(1)
Foreign exchange contracts	Crude oil, refined products and LPG sales and related revenues		5		5
Foreign exchange contracts	Crude oil, refined products and LPG purchases and related costs		2		(3)
Foreign exchange contracts	Interest income and other income (expense), net		(2)		(2)
Total		$	60	$	120

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet as of June 30, 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	$	94	Other current liabilities	$	(98)
	Other long-term assets		48	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		5	Other long-term liabilities		(1)
Total derivatives designated as hedging instruments under SFAS 133		$	148		$	(99)
Derivatives not designated as hedging instruments under SFAS 133:						
Commodity contracts	Other current assets	$	102	Other current liabilities	$	(113)
	Other long-term assets		91	Other long-term liabilities		(57)
Interest rate contracts	Other current assets		1	Other current liabilities		
	Other long-term assets			Other long-term liabilities		
Foreign exchange contracts	Other current assets		1	Other current liabilities		(2)
	Other long-term assets			Other long-term liabilities		
Total derivatives not designated as hedging instruments under SFAS 133		$	195		$	(172)
Total derivatives		$	343		$	(271)

As of June 30, 2009, there was a net loss of $42 million deferred in AOCI. The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the related physical purchase or delivery of the underlying commodity, (ii) interest expense accruals associated with the underlying debt instruments and (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain Canadian Dollar-denominated intercompany interest receivables. Of the total net loss deferred in AOCI at June 30, 2009, a net loss of approximately $106 million is expected to be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 75% is expected to be reclassified to earnings prior to 2012 with the remaining deferred gain being reclassified 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 June 30, 2009 and 2008, no amounts were reclassified from AOCI to earnings as a result of forecasted transactions no longer considered to be probable of occurring. During the six months ended June 30, 2009, we reclassed a deferred gain of approximately $6 million from AOCI to other income as a result of anticipated hedge transactions that are no longer considered to be probable of occurring. During the six months ended June 30, 2008, no amounts were reclassed from AOCI as a result of anticipated hedge transactions that are no longer considered to be probable of occurring.

Amounts of gain/(loss) recognized in AOCI on derivatives (effective portion) during the three and six months ended June 30, 2009 are as follows (in millions):

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Commodity contracts	$ (104)	$ (82)
Foreign exchange contracts	(4)	(2)
Total	$ (108)	$ (84)

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. Our broker receivable was approximately $5 million and $81 million as of June 30, 2009 and December 31, 2008, respectively. At June 30, 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 June 30, 2009. As required by SFAS 157, financial assets and liabilities are classified in their

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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 June 30, 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	$ 289	$ 12	$ 34	$ 335	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives			1	1			5	5
Foreign currency derivatives			7	7			18	18
Total assets at fair value	$ 289	$ 12	$ 42	$ 343	$ 235	$ 9	$ 135	$ 379
Liabilities:								
Commodity derivatives	$ (224)	$	$ (44)	$ (268)	$ (330)	$	$ (56)	$ (386)
Foreign currency derivatives			(3)	(3)			(5)	(5)
Total liabilities at fair value	$ (224)	$	$ (47)	$ (271)	$ (330)	$	$ (61)	$ (391)
Net asset/(liability) at fair value	$ 65	$ 12	$ (5)	$ 72	$ (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 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, which include derivative contracts such as 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 the following derivatives:

- 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

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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 June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Balance as of April 1, 2009 and 2008 and January 1, 2009 and 2008, respectively	$ 26	(31)	$ 74	(21)
Realized and unrealized gains/(losses):				
Included in earnings	8	(55)	54	(81)
Included in other comprehensive income/(loss)	(21)	3	(22)	(2)
Purchases, issuances, sales and settlements	(18)	27	(111)	48
Transfers into or (out of) level 3				
Ending Balance as of June 30, 2009 and 2008, respectively	$ (5)	$ (56)	$ (5)	$ (56)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held as of June 30, 2009 and 2008, respectively	$ (8)	$ (36)	$ (8)	$ (60)

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and are therefore offset by the underlying transactions.

Note 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 Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs,

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are estimated to be approximately $5 million to $6 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. 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 L.P., et al Debtors (U.S. Bankruptcy Court Delaware). 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. Certain SemCrude creditors have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude, and the continuation of such lien when SemCrude sold the oil to subsequent purchasers such as us. 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 Plaintiff filed a motion for summary judgment to determine that the Clean Water Act does not require Plaintiff to demonstrate that PPS was the proximate cause of the release of oil. The motion was granted. The court also affirmed that $3.7 million was the statutory maximum permissible penalty for the release. 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 imposed, 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 Mobil Corp. v. GATX Corp. (Superior Court of New Jersey Gloucester County). This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE (and other petroleum product) contamination at the Pacific Atlantic Terminals LLC (PAT) facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $8 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. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the contamination.

New Jersey Dep t of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to Exxon v. GATX, the New Jersey Department of Environmental Protection (NJDEP) has brought suit against GATX and Exxon to recover natural resources damages associated with the contamination. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. Discussions with the NJDEP have commenced.

Other Pacific-Legacy Matters. At the time of its merger with Plains, Pacific had completed a number of acquisitions that had not been fully integrated into its operations. Accordingly, we have and may become aware of various instances in which some of these operations may not have been fully compliant with applicable environmental and safety regulations. Although we have been working to bring all of these operations into compliance with applicable requirements, any past noncompliance could result in the imposition of fines, penalties or corrective action requirements by governmental entities. We have, for instance, recently learned that some of the fuel handling activities at two Pacific terminals in Colorado, which activities were performed at the request of customers, may not have been fully compliant with the EPA s interpretation of certain fuel reporting and record-keeping obligations imposed under the federal Clean Air Act. We have responded to information requests from the EPA regarding these past practices and have been cooperating with EPA in its evaluation of this matter. Although we believe that our operations are presently in material compliance with applicable requirements, it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us, or on a portion of our operations, as a result of any past noncompliance that may have occurred.

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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 (reduce) the releases from such assets (in terms of frequency or volume) 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 June 30, 2009, our reserve for environmental liabilities totaled approximately $46 million, of which approximately $10 million is classified as short-term and $36 million is classified as long-term. At June 30, 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 facts known and believed to be relevant 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.

Insurance

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 insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the 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.

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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 June 30, 2009				
Revenues:				
External Customers	$ 130	$ 53	$ 4,099	$ 4,282
Intersegment (1)	108	32		140
Total revenues of reportable segments	$ 238	$ 85	$ 4,099	$ 4,422
Equity earnings of unconsolidated entities	$ 2	$ 3	$	$ 5
Segment profit (2) (3) (4)	$ 114	$ 52	$ 78	$ 244
Maintenance capital	$ 16	$ 3	$ 3	$ 22
Three Months Ended June 30, 2008				
Revenues:				
External Customers	$ 143	$ 37	$ 8,880	$ 9,060
Intersegment (1)	89	28	1	118
Total revenues of reportable segments	$ 232	$ 65	$ 8,881	$ 9,178
Equity earnings of unconsolidated entities	$ 1	$ 3	$	$ 4
Segment profit/(loss) (2) (3) (4)	$ 106	$ 36	$ (5)	$ 137
Maintenance capital	$ 11	$ 5	$ 1	$ 17
Six Months Ended June 30, 2009				
Revenues:				
External Customers	$ 254	$ 100	$ 7,231	$ 7,585
Intersegment (1)	210	62		272
Total revenues of reportable segments	$ 464	$ 162	$ 7,231	$ 7,857
Equity earnings of unconsolidated entities	$ 3	$ 5	$	$ 8
Segment profit (2) (3) (4)	$ 226	$ 98	$ 238	$ 562
Maintenance capital	$ 30	$ 10	$ 4	$ 44
Six Months Ended June 30, 2008				
Revenues:				
External Customers	$ 268	$ 70	$ 15,917	$ 16,255
Intersegment (1)	169	54	1	224
Total revenues of reportable segments	$ 437	$ 124	$ 15,918	$ 16,479
Equity earnings of unconsolidated entities	$ 3	$ 4	$	$ 7
Segment profit (2) (3) (4)	$ 195	$ 68	$ 52	$ 315
Maintenance capital	$ 25	$ 10	$ 2	$ 37

(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.

(3) Marketing segment profit includes interest expense on contango inventory purchases of $3 million and $4 million for the three months ended June 30, 2009 and 2008, respectively, and $5 million and $10 million for the six months ended June 30, 2009 and 2008, respectively.

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

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	For the Three Months Ended June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Segment profit	$ 244	$ 137	$ 562	$ 315
Depreciation and amortization	(56)	(52)	(114)	(100)
Interest expense	(56)	(49)	(107)	(91)
Interest income and other income/(expense), net	2	10	5	12
Income tax benefit/(expense)	2	(5)	1	(3)
Net income	$ 136	$ 41	$ 347	$ 133

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 June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,669	$ 3,107	$ 154	$ (3,008)	$ 2,922
Property, plant and equipment, net		4,334	921		5,255
Investment in unconsolidated entities	4,736	1,206		(5,686)	256
Other assets	23	1,787	316		2,126
Total assets	$ 7,428	$ 10,434	$ 1,391	$ (8,694)	$ 10,559
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 329	$ 5,635	$ 252	$ (3,008)	$ 3,208
Long-term debt	3,393	5			3,398
Other long-term liabilities		246	1		247
Total liabilities	3,722	5,886	253	(3,008)	6,853
Partners capital excluding noncontrolling interest	3,643	4,485	1,138	(5,623)	3,643
Noncontrolling interest	63	63		(63)	63

Total partners capital		3,706		4,548		1,138		(5,686)		3,706
Total liabilities and partners capital	$	7,428	$	10,434	$	1,391	$	(8,694)	$	10,559

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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 June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 416	$ 37	$	$ 453
Field operating costs		(150)	(10)		(160)
General and administrative expenses		(51)	(3)		(54)
Depreciation and amortization	(1)	(48)	(7)		(56)
Operating income (loss)	(1)	167	17		183
Equity earnings in unconsolidated entities	194	19		(208)	5
Interest expense	(57)	1			(56)
Interest and other income (expense), net		2			2
Income tax benefit		2			2
Net income (loss)	$ 136	$ 191	$ 17	$ (208)	$ 136

	Three Months Ended June 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 307	$ 29	$	$ 336
Field operating costs		(143)	(9)		(152)
General and administrative expenses		(47)	(4)		(51)

Depreciation and amortization		(1)		(46)		(5)				(52)
Operating income (loss)		(1)		71		11				81
Equity earnings in unconsolidated entities		91		12				(99)		4
Interest expense		(47)		(2)						(49)
Interest and other income (expense), net		(2)		12						10
Income tax expense				(5)						(5)
Net income (loss)	$	41	$	88	$	11	$	(99)	$	41

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Condensed Consolidating Statements of Operations

	Six Months Ended June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 900	$ 66	$	$ 966
Field operating costs		(293)	(19)		(312)
General and administrative expenses		(95)	(5)		(100)
Depreciation and amortization	(2)	(99)	(13)		(114)
Operating income (loss)	(2)	413	29		440
Equity earnings in unconsolidated entities	458	31		(481)	8
Interest expense	(109)	2			(107)
Interest and other income (expense), net		5			5
Income tax benefit		1			1
Net income (loss)	$ 347	$ 452	$ 29	$ (481)	$ 347

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

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

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Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 347	$ 452	$ 29	$ (481)	$ 347
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	2	99	13		114
Equity compensation charge		30			30
Other	(454)	(28)		481	(1)
Changes in assets and liabilities, net of acquisitions	4	(176)	(31)		(203)
Net cash provided by operating activities	(101)	377	11		287
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions		(56)			(56)
Additions to property, equipment and other		(219)	(9)		(228)
Investment in unconsolidated entities	(5)				(5)
Cash received for sale of noncontrolling interest in a subsidiary		26			26
Proceeds from the sale of assets and other		10			10
Net cash used in investing activities	(5)	(239)	(9)		(253)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	(158)	(301)			(459)
Net borrowings on short-term letter of credit and hedged inventory facility		157			157
Net proceeds from the issuance of senior notes	350				350
Net proceeds from the issuance of common units	210				210
Distributions paid to common unitholders and general partner	(291)				(291)
Other financing activities	(5)				(5)
Net cash used in financing activities	106	(144)			(38)
Net decrease in cash and cash equivalents		(6)	2		(4)
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 2	$ 3	$ 2	$	$ 7

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Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 133	$ 219	$ 22	$ (241)	$ 133
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	1	89	10		100
Equity compensation expense		24			24
Other	(214)	(41)		242	(13)
Changes in assets and liabilities, net of acquisitions	(541)	892	(18)	(1)	332
Net cash provided by operating activities	(621)	1,183	14		576
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions		(661)			(661)
Additions to property, equipment and other		(287)	(14)		(301)
Investment in unconsolidated entities	(40)				(40)
Proceeds from the sale of assets		15			15
Net cash used in investing activities	(40)	(933)	(14)		(987)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		(204)			(204)
Net repayments on short-term letter of credit and hedged inventory facility		(56)			(56)
Proceeds from the issuance of senior notes	597				597
Net proceeds from the issuance of common units	315				315
Distributions paid to common unitholders and general partner	(251)				(251)
Other financing activities	(5)				(5)
Net cash used in financing activities	656	(260)			396
Effect of translation adjustment on cash		2			2
Net decrease in cash and cash equivalents	(5)	(8)			(13)
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ (4)	$ 15	$	$	$ 11

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 and Acquisitions

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- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates

Overview of Operating Results, Capital Spending and Significant Activities

During the first six months of 2009, all three of our segments provided favorable operating results, particularly our marketing segment which benefited from the mark-to-market of certain derivative contracts, a favorable contango crude oil market structure; and favorable LPG margins. Additional key items impacting operating results during the first six months of 2009 include:

- Contributions to earnings from (i) mid-year 2008 adjustments in pipeline tariff rates and (ii) the acquisition of Rainbow Pipe Line Company, Ltd. (Rainbow) in May 2008, offset partially by the impact of tarriff settlements in 2009.

- Increased earnings from expansion projects and acquisitions completed within our facilities segment.

- Equity compensation plan expense of approximately $30 million for the six months of 2009 compared to $24 million for the corresponding prior year period. The increased expense primarily resulted from an increase in unit price for the first six months of 2009 compared to a decrease in unit price for the first six months of 2008.

- The issuance of 5,750,000 limited partner units at $36.90 per unit for net proceeds of approximately $210 million in March 2009.

- The issuance of $350 million of senior notes for net proceeds of approximately $347 million in April 2009.

Internal Growth Projects and Acquisitions

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):

	Six Months Ended June 30, 2009	2008
Acquisition capital (1)	$ 60	$ 688
Investment in unconsolidated entities	4	40
Internal growth projects	157	256
Maintenance capital	44	37
Total	$ 265	$ 1,021

(1) During the second quarter of 2009, we completed two acquisitions aggregating approximately $60 million, which included a crude oil pipeline that is reflected in our transportation segment and a natural gas processing business that is reflected in our facilities segment. In connection with these transactions, we allocated approximately $9 million to goodwill.

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):

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Projects	2009
St. James Phase III (1)	$ 73
Rangeland tankage and connections	35
Kerrobert pumping project	34
Patoka Phase II & III	30
Cushing Phase VII	29
Nipisi storage and truck terminal	20
Salt Lake City pipeline	14
Pier 400	13
Paulsboro	12
Other projects, including acquisition related expansion projects (2)	110
Total	$ 370

(1) Includes a dock and condensate tanks.

(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 June 30,		Three Months Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Six Months Favorable/ (Unfavorable) Variance	
	2009	2008	$	%	2009	2008	$	%
Transportation segment profit	$ 114	$ 106	$ 8	8%	$ 226	$ 195	$ 31	16%
Facilities segment profit	52	36	16	44%	98	68	30	44%
Marketing segment profit	78	(5)	83	1,660%	238	52	186	358%
Total segment profit	244	137	107	78%	562	315	247	78%
Depreciation and amortization	(56)	(52)	(4)	(8)%	(114)	(100)	(14)	(14)%
Interest expense	(56)	(49)	(7)	(14)%	(107)	(91)	(16)	(18)%
Interest income and other income/(expense), net	2	10	(8)	(80)%	5	12	(7)	(58)%
Income tax benefit/(expense)	2	(5)	7	140%	1	(3)	4	133%
Net income	$ 136	$ 41	$ 95	232%	$ 347	$ 133	$ 214	161%

Earnings per basic limited partner unit	$ 0.79	$ 0.09	$ 0.70	778%	$ 2.20	$ 0.65	$ 1.55	238%
Earnings per diluted limited partner unit	$ 0.78	$ 0.09	$ 0.69	767%	$ 2.18	$ 0.64	$ 1.54	241%
Basic weighted average units outstanding	129	120	9	8%	126	118	8	7%
Diluted weighted average units outstanding	130	121	9	7%	127	119	8	7%

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Transportation Segment

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Three Months Favorable/ (Unfavorable) Variance $	Three Months Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Six Months Favorable/ (Unfavorable) Variance $	Six Months Favorable/ (Unfavorable) Variance %
Revenues								
Tariff activities	$ 214	$ 199	$ 15	8%	$ 416	$ 373	$ 43	12%
Trucking	24	33	(9)	(27)%	48	64	(16)	(25)%
Total transportation revenues	238	232	6	3%	464	437	27	6%
Costs and Expenses								
Trucking costs	(16)	(23)	7	30%	(32)	(45)	13	29%
Field operating costs (excluding equity compensation expense)	(86)	(81)	(5)	(6)%	(163)	(160)	(3)	(2)%
Equity compensation expense - operations (2)	(2)	(1)	(1)	(100)%	(4)	(2)	(2)	(100)%
Segment G&A expenses (excluding equity compensation expense)	(14)	(14)		%	(30)	(28)	(2)	(7)%
Equity compensation expense - general and administrative (2)	(8)	(8)		%	(12)	(10)	(2)	(20)%
Equity earnings in unconsolidated entities	2	1	1	100%	3	3		%
Segment profit	$ 114	$ 106	$ 8	8%	$ 226	$ 195	$ 31	16%
Maintenance capital	$ 16	$ 11	$ 5	45%	$ 30	$ 25	$ 5	20%
Segment profit per barrel	$ 0.41	$ 0.38	$ 0.03	7%	$ 0.42	$ 0.37	$ 0.05	13%

Average Daily Volumes (in thousands of barrels per day) (3)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Three Months Favorable/ (Unfavorable) Variance Volumes	Three Months Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Six Months Favorable/ (Unfavorable) Variance Volumes	Six Months Favorable/ (Unfavorable) Variance %
Tariff activities								
All American	42	43	(1)	(2)%	39	45	(6)	(13)%
Basin	440	377	63	17%	417	370	47	13%
Capline	204	247	(43)	(17)%	205	218	(13)	(6)%
Line 63/Line 2000	145	160	(15)	(9)%	133	161	(28)	(17)%
Salt Lake City Area Systems	139	96	43	45%	121	96	25	26%
West Texas/New Mexico Area Systems	374	382	(8)	(2)%	384	366	18	5%
Manito	61	72	(11)	(15)%	63	70	(7)	(10)%
Rainbow	181	132	49	37%	188	66	122	185%
Rangeland	53	59	(6)	(10)%	56	60	(4)	(7)%
Refined products	91	107	(16)	(15)%	94	111	(17)	(15)%
Other	1,260	1,274	(14)	(1)%	1,201	1,234	(33)	(3)%

Tariff activities total	2,990	2,949	41	1%	2,901	2,797	104	4%
Trucking	84	89	(5)	(6)%	86	93	(7)	(8)%
Transportation segment total	3,074	3,038	36	1%	2,987	2,890	97	3%

(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.

Transportation segment profit and segment profit per barrel for the three and six months ended June 30, 2009 were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for

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both the three and six months ended June 30, 2009 as compared to the three and six months ended June 30, 2008. The significant variances in revenues and average daily volumes between the comparative periods are discussed below:

- Acquisitions and Expansion Projects The Rainbow acquisition was effective May 1, 2008 and contributed additional volumes of 122,000 barrels per day and approximately $18 million of additional tariff revenues (net of the resolution of tariff disputes) during the six months ended June 30, 2009 relative to the same period of 2008.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Loss allowance revenues increased by approximately $5 million and $7 million for the three and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008.

- Rate increases Rates increased on certain of our pipeline systems after the second quarter of 2008 as a result of indexing by the Federal Energy Regulation Commission (FERC) and normal course of business adjustments elsewhere, which resulted in increased revenues for the three and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008.

Field Operating Costs. Excluding equity compensation costs (see below) and the Rainbow acquisition related costs of approximately $4 million and $9 million for the three and six months ended June 30, 2009, field operating costs decreased for the three and six months ended June 30, 2009 compared to the same periods during 2008 primarily due to decreases in (i) fuel and utilities costs and (ii) costs associated with API 653 compliance and pipeline integrity testing. These decreases were partially offset by the increases in (i) payroll and benefits, (ii) maintenance costs and (iii) property taxes.

Equity Compensation Charges. Equity compensation charges increased in 2009 compared to 2008 primarily as a result of an increase in unit price for the six-month period ended June 30, 2009 compared to a decrease in unit price for the six-month period ended June 30, 2008. See Note 8 to our Condensed Consolidated Financial Statements for additional information on our Equity Compensation Plans.

Facilities Segment

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

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Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Three Months Favorable/ (Unfavorable) Variance $	Three Months Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Six Months Favorable/ (Unfavorable) Variance $	Six Months Favorable/ (Unfavorable) Variance %
Storage and terminalling revenues (1)	$ 85	$ 65	$ 20	31%	$ 162	$ 124	$ 38	31%
Field operating costs	(27)	(25)	(2)	(8)%	(54)	(48)	(6)	(13)%
Segment G&A expenses (excluding equity compensation expense)	(6)	(4)	(2)	(50)%	(11)	(8)	(3)	(38)%
Equity compensation expense - general and administrative (2)	(3)	(3)		%	(4)	(4)		%
Equity earnings in unconsolidated entities	3	3		%	5	4	1	25%
Segment profit	$ 52	$ 36	$ 16	44%	$ 98	$ 68	$ 30	44%
Maintenance capital	$ 3	$ 5	$ (2)	(40)%	$ 10	$ 10	$	%
Segment profit per barrel	$ 0.29	$ 0.22	$ 0.07	31%	$ 0.28	$ 0.21	$ 0.07	32%

Volumes (3)(4)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Three Months Favorable/ (Unfavorable) Variance Volumes	Three Months Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Six Months Favorable/ (Unfavorable) Variance Volumes	Six Months Favorable/ (Unfavorable) Variance %
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	52	4	8%	55	52	3	6%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet (bcf))	20	14	6	43%	18	13	5	38%
LPG processing (average throughput in thousands of barrels per day)	17	17		%	16	16		%
Facilities segment total (average monthly capacity in millions of barrels)	60	55	5	9%	59	54	5	9%

(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 and six months ended June 30, 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 and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008. The significant variances in revenues and average daily volumes between the comparative periods are discussed below:

- Expansion Projects - The Paulsboro, Patoka, St. James and Ft. Laramie expansion projects resulted in an increase in revenues of approximately $8 million and $16 million and volumes of approximately 6 million barrels per month and 6 million barrels per month for the three- and six- month periods ended June 30, 2009 compared to the same periods of 2008.

- Acquisitions - Revenues and volumes for the three and six months ended June 30, 2009 were impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008, and the natural gas processing acquisition, which closed during the second quarter of 2009. The San Pedro and natural gas processing acquisitions contributed approximately $4 million and $7 million in revenues and volumes of approximately 1 million barrels per month and 1 million barrels per month for the three- and six- month periods ended June 30, 2009 compared to the same periods of 2008, respectively.

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• Rate Increases Revenues for the three and six months ended June 30, 2009 increased as a result of higher lease rates received at various facilities, due in part to our decision in mid-2008 to increase the amount of tankage leased to third parties as well as general escalations on existing leases.

Field Operating Costs. Field operating costs (excluding equity compensation charges) have increased in most categories for the three and six months ended June 30, 2009 in comparison to the three and six months ended June 30, 2008 primarily related to the expansion projects and acquisitions discussed above. The 2009 increased costs primarily relate to (i) payroll and benefits, (ii) maintenance costs and (iii) property taxes, partially offset by a decrease in fuel costs.

Marketing Segment

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

Operating Results (1) (in millions, except per barrel amounts)	**Three Months Ended June 30, 2009**	**Three Months Ended June 30, 2008**	**Three Months Favorable/ (Unfavorable) Variance $**	**Three Months Favorable/ (Unfavorable) Variance %**	**Six Months Ended June 30, 2009**	**Six Months Ended June 30, 2008**	**Six Months Favorable/ (Unfavorable) Variance $**	**Six Months Favorable/ (Unfavorable) Variance %**
Revenues	$ 4,099	$ 8,881	$ (4,782)	(54)%	$ 7,231	$ 15,918	$ (8,687)	(55)%
Purchases and related costs (3)	(3,951)	(8,819)	4,868	55%	(6,854)	(15,739)	8,885	56%
Field operating costs	(47)	(45)	(2)	(4)%	(96)	(87)	(9)	(10)%
Segment G&A expenses (excluding equity compensation expense)	(17)	(16)	(1)	(6)%	(33)	(32)	(1)	(3)%
Equity compensation expense - general and administrative (4)	(6)	(6)		%	(10)	(8)	(2)	(25)%
Segment profit/(loss) (2)	$ 78	$ (5)	$ 83	1,660%	$ 238	$ 52	$ 186	358%
Maintenance capital	$ 3	$ 1	$ 2	200%	$ 4	$ 2	$ 2	100%
Segment profit per barrel (5)	$ 1.11	$ (0.06)	$ 1.17	1,950%	$ 1.60	$ 0.32	$ 1.28	400%

Average Daily Volumes (6) (in thousands of barrels per day)	**Three Months Ended June 30, 2009**	**Three Months Ended June 30, 2008**	**Three Months Favorable/ (Unfavorable) Variance Volumes**	**Three Months Favorable/ (Unfavorable) Variance %**	**Six Months Ended June 30, 2009**	**Six Months Ended June 30, 2008**	**Six Months Favorable/ (Unfavorable) Variance Volumes**	**Six Months Favorable/ (Unfavorable) Variance %**
Crude oil lease gathering purchases	623	672	(49)	(7)%	627	676	(49)	(7)%
Refined products sales	36	24	12	50%	36	22	14	64%
LPG sales	60	51	9	18%	102	93	9	10%
Waterborne foreign crude oil imported	57	102	(45)	(44)%	57	89	(32)	(36)%
Marketing segment total	776	849	(73)	(9)%	822	880	(58)	(7)%

(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 $3 million and $5 million for the three and six months ended June 30, 2009, respectively, compared to $4 million and $10 million for the three and six months ended June 30, 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.

Marketing segment profit and segment profit per barrel for the three and six months ended June 30, 2009 were impacted by the following:

Revenues and Purchases and Related Costs. The absolute amount of our revenues and purchases decreased in the three and six months ended June 30, 2009 as compared to the three and six months ended June 30, 2008, primarily resulting from lower commodity prices in the 2009 period. The NYMEX benchmark price of crude oil ranged from $45 to $73 per barrel and $100 to $143 per barrel during the three months ended June 30, 2009 and 2008, respectively, and from $34 to $73 per barrel and $86 to $143 per barrel during the six months

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ended June 30, 2009 and 2008, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for 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 following:

- *Contango Market Structure* - The favorable impact of a strong contango market on earnings in the first six months of 2009, while the corresponding market conditions during the first six months of 2008 were slightly backwardated. The market structure for the first six months of 2009 ranged from $0.43 per barrel to $8.49 per barrel contango and averaged approximately $2.67 per barrel contango. The market structure averaged approximately $0.45 per barrel backwardation for the first six months of 2008.

- *LPG Marketing* Higher results from our LPG operations in the first six months of 2009 as compared to the respective period in 2008. We captured higher sales margins in the first quarter of 2009 primarily as a result of higher fixed price sales satisfied by lower average cost inventory, 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 second quarter and first six months of 2008 as higher profits were recognized earlier in the 2007/2008 season due to increased demand.

- The significant impact of the mark-to-market of certain derivative contracts on our results for the first six months of 2009 as compared to the same period of 2008. The three and six months ended June 30, 2008 include losses of approximately $87 million and $92 million, respectively, from derivative positions associated with underlying physical activity that will occur in periods subsequent to June 30, 2008 while the three and six months ended June 30, 2009 include gains of approximately $18 million and $44 million, respectively, associated with derivative positions related to underlying physical activity that will occur in subsequent periods.

Volumes. The crude oil lease gathering purchases average daily volumes decreased 49,000 barrels per day for both the three and six months ended 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 45,000 barrels per day and 32,000 barrels per day for the three and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008, respectively, due to the lack of opportunities to import such crude at a profitable margin.

Field Operating Costs. Field operating costs (excluding equity compensation charges) have increased in several categories for the six months ended June 30, 2009 in comparison to the six months ended June 30, 2008. The 2009 increased costs primarily relate to (i) payroll and benefits and (ii) maintenance costs, partially offset by a decrease in third-party trucking fees and fuel costs.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased approximately $4 million and $14 million for the three and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008, respectively. Such increases were primarily the result of an increased amount of depreciable assets resulting from our 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 and six months ended June 30, 2009 increased approximately $7 million and $16 million in comparison to the three and six months ended June 30, 2008, respectively. The increase in both periods primarily resulted from the issuance of $600 million of senior notes completed during the second quarter of 2008. The increase for the six months ended June 30, 2009 was also impacted by the issuance of the $350 million of senior notes completed during the second quarter of 2009. Additionally, interest capitalized to various internal growth projects was lower for both the three and six months ended June 30, 2009 as compared to the same periods in 2008 as a result of completion in subsequent quarters of projects under construction at June 30, 2008. These increases for both periods stated were partially offset by an improvement in variable interest charges under our short-term credit facilities as a result of lower interest rates.

Income Tax Expense. Income tax expense decreased approximately $7 million and $4 million for the three and six months ended June 30, 2009 compared to the three and six months ended June 30, 2008, respectively. The decrease primarily related to a reduction in the statutory tax rate and a reduction of net income earned for a portion of our Canadian operations. See Note 10 to our Condensed Consolidated Financial Statements regarding the tax treatment of certain of our Canadian subsidiaries.

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Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At June 30, 2009, we had a working capital deficit of approximately $286 million, approximately $1.2 billion of availability under our committed revolving credit facility and approximately $89 million of availability under our committed hedged inventory facility. Our availability under our credit facilities was favorably impacted by our July 2009 issuance of $500 million senior notes. See Equity and Debt Financing Activities below. 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 our cash flow from 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 was positively impacted by cash generated by our recurring operations. 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 six months of 2009, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and an increase in prices and was primarily related to our crude oil contango market storage activities. The increase in crude oil inventory was partially offset by a decrease in LPG inventory as a result of the sale of LPG inventory in the beginning of the year resulting from end users increased demand for heating requirements in the winter months. The net increased levels of inventory were financed through borrowings under our credit facilities resulting in a negative impact to our operating cash flow for the period.

Our cash flow provided by operating activities in the first six months of 2008 was approximately $576 million, resulting from cash generated by our recurring operations and our primary drivers. Our operating activities were also positively impacted by (i) an increase in prepayments from our counterparties and (ii) our NYMEX margin activities.

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 and July 2009 debt offerings, we have $938 million of unissued securities remaining available under this registration statement.

Senior Notes. On August 15, 2009, our $175 million Senior Notes will mature. We will utilize our cash on hand and available capacity under our credit facilities to retire these Senior Notes.

In July 2009, we completed the issuance of $500 million of 4.25% Senior Notes due September 1, 2012. The senior notes were sold at 99.802% of face value. Interest payments are due on March 1 and September 1 of each year, beginning on March 1, 2010. We used the net proceeds from this offering to supplement the capital available under our existing hedged inventory facility to fund working capital needs associated with base levels of routine foreign crude oil import and for seasonal LPG inventory requirements.

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 six months ended June 30, 2009, we had net repayments on our revolving credit facilities of approximately $459 million. These net repayments resulted primarily from sales of LPG inventory that was liquidated during the period, our March 2009 equity offering and our April 2009 debt offering. During the same period, we had net borrowings on our hedged inventory facility of approximately $157 million, which primarily resulted from the favorable contango market structure. During the six months ended June 30, 2008, we had net repayments on our revolving credit facilities and hedged inventory facility of approximately $204 million and $56 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 and Acquisitions 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 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

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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 include our best estimate as of June 30, 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.

	2009	2010	2011	2012	2013	2014 and Thereafter	Total
Long-term debt and interest payments (1)	$ 291	$ 229	$ 229	$ 425	$ 461	$ 4,726	$ 6,361
Leases (2)	$ 35	$ 55	$ 47	$ 40	$ 24	$ 238	$ 439
Crude oil, refined products and LPG purchases (3)	$ 3,742	$ 1,062	$ 466	$ 286	$ 4	$	$ 5,560

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at June 30, 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 and trailers used in our gathering activities.

(3) Amounts are based on estimated volumes and market prices based on average activity during June 2009. The actual physical volume purchased and actual settlement prices will 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 June 30, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $51 million and $51 million, respectively.

Capital Contributions to PAA/Vulcan Gas Storage, LLC

We and Vulcan Gas Storage LLC (Vulcan Gas Storage) are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. During the first six months of 2009, we made additional contributions of approximately $4 million to PAA/Vulcan Gas Storage, LLC (PVGS) and received distributions of approximately $4 million from PVGS. Vulcan Gas Storage made the same net contribution as we did during the first six months of 2009. Such contributions did not result in any change in ownership interest.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

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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;
- 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;

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- 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 deteriorated 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.

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 June 30, 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	$ 71	$ 28
Swaps and options contracts	66	$ 54
LPG and other:		
Futures contracts	(32)	$ (2)
Swaps, options and other contracts (1)	(38)	$ (37)
Total Fair Value	$ 67	

(1) Amount includes an asset of approximately $27 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.

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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.

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 of which we are unaware 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.

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Item 6. EXHIBITS

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

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).