PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
November 06, 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 September 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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

At November 5, 2009, there were outstanding 136,135,988 Common Units.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except units)

		September 30, 2009		December 31, 2008
		(unaudited)		
ASSETS				
CURRENT ASSETS				
Cash and cash equivalents	$	16	$	11
Trade accounts receivable and other receivables, net		1,641		1,525
Inventory		1,174		801
Other current assets		193		259
Total current assets		3,024		2,596
PROPERTY AND EQUIPMENT		7,037		5,727
Accumulated depreciation		(840)		(668)
		6,197		5,059
OTHER ASSETS				
Linefill and base gas		479		425
Long-term inventory		129		139
Investment in unconsolidated entities		68		257
Goodwill		1,270		1,210
Other, net		326		346
Total assets	$	11,493	$	10,032
LIABILITIES AND PARTNERS CAPITAL				
CURRENT LIABILITIES				
Accounts payable and accrued liabilities	$	1,827	$	1,507
Short-term debt (Note 6)		692		1,027
Other current liabilities		340		426
Total current liabilities		2,859		2,960
LONG-TERM LIABILITIES				
Long-term debt under credit facilities and other		7		40
Senior notes, net of unamortized net discount of $15 and $6, respectively		4,135		3,219
Other long-term liabilities and deferred credits		265		261
Total long-term liabilities		4,407		3,520
COMMITMENTS AND CONTINGENCIES (NOTE 12)				

PARTNERS CAPITAL				
Common unitholders (136,135,988 and 122,911,645 units outstanding, respectively)		4,066		3,469
General partner		97		83
Total partners capital excluding noncontrolling interest		4,163		3,552
Noncontrolling interest		64		
Total partners capital		4,227		3,552
Total liabilities and partners capital	$	11,493	$	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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(unaudited)		(unaudited)	
REVENUES				
Sales and related revenues	$ 4,645	$ 8,676	$ 11,876	$ 24,593
Pipeline tariff activities, trucking and related revenues	147	147	401	416
Storage, terminalling, processing and related revenues	65	39	165	109
Total revenues	4,857	8,862	12,442	25,118
COSTS AND EXPENSES				
Purchases and related costs	4,417	8,369	11,036	23,929
Field operating costs	163	162	474	458
General and administrative expenses	52	39	153	130
Depreciation and amortization	59	49	173	150
Total costs and expenses	4,691	8,619	11,836	24,667
OPERATING INCOME	166	243	606	451
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	5	4	13	11
Interest expense (net of capitalized interest of $4, $4, $9 and $14, respectively)	(59)	(52)	(165)	(143)
Other income/(expense), net	12	14	17	27
INCOME BEFORE TAX	124	209	471	346
Current income tax expense	(2)	(3)	(5)	(9)
Deferred income tax benefit			4	2
NET INCOME	122	206	470	339
Less: Net income attributable to noncontrolling interest			(1)	
NET INCOME ATTRIBUTABLE TO PLAINS	$ 122	$ 206	$ 469	$ 339
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 88	$ 173	$ 370	$ 256
GENERAL PARTNER	$ 34	$ 33	$ 99	$ 83
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 1.42	$ 2.84	$ 2.10
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 1.41	$ 2.82	$ 2.08
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	130	123	128	120
	131	124	129	121

DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING

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)

	Nine Months Ended September 30, 2009	2008
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 470	$ 339
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	173	150
Equity compensation charge	47	27
Inventory valuation adjustment		65
Gain on sale of investment assets		(12)
Net gain on purchase of remaining 50% interest in PNGS	(9)	
Net cash paid for terminated interest rate and foreign currency hedging instruments	(9)	(2)
Equity earnings in unconsolidated entities, net of distributions	(6)	(4)
Other	(19)	(9)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	52	(410)
Inventory	(349)	(521)
Accounts payable and other liabilities	(3)	616
Net cash provided by operating activities	347	239
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(117)	(662)
Additions to property, equipment and other	(354)	(446)
Investment in unconsolidated entities	(4)	(35)
Cash received for sale of noncontrolling interest in a subsidiary	26	
Net cash received/(paid) for linefill	8	(8)
Proceeds from the sale of assets and other	4	36
Net cash used in investing activities	(437)	(1,115)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on revolving credit facility	(454)	259
Net borrowings/(repayments) on hedged inventory facility	(180)	111
Repayment of PNGS debt	(446)	
Proceeds from the issuance of senior notes (Note 6)	1,346	597
Repayments of senior notes	(175)	
Net proceeds from the issuance of common units (Note 8)	458	315
Distributions paid to common unitholders (Note 8)	(344)	(308)
Distributions paid to general partner (Note 8)	(98)	(84)
Other financing activities	(9)	(4)
Net cash provided by financing activities	98	886
Effect of translation adjustment on cash	(3)	3
Net increase in cash and cash equivalents	5	13
Cash and cash equivalents, beginning of period	11	24
Cash and cash equivalents, end of period	$ 16	$ 37
Cash paid for interest, net of amounts capitalized	$ 150	$ 143

Cash paid for income taxes	$	7	$	8

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Partners
	Units	Amount	Partner	Interest	Interest	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		370	99	469	1	470
Issuance of common units	11	447	9	456		456
Issuance of common units in connection with the PNGS Acquisition	2	91	2	93		93
Issuance of common units under Long Term Incentive Plans (LTIP)		12		12		12
Distributions		(344)	(98)	(442)		(442)
Class B Units of Plains AAP, L.P.		1	2	3		3
Other comprehensive income		56	1	57		57
Balance, September 30, 2009	**136**	**$ 4,066**	**$ 97**	**$ 4,163**	**$ 64**	**$ 4,227**

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(unaudited)		(unaudited)	
Net income attributable to Plains	$ 122	$ 206	$ 469	$ 339
Other comprehensive income/(loss)	210	(4)	57	(50)
Comprehensive income	$ 332	$ 202	$ 526	$ 289

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

Derivative	Translation

	Instruments	Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2008	$ 161	$ (86)	$	$ 75
Reclassification adjustments	(19)			(19)
Changes in fair value of outstanding hedge positions	(61)			(61)
Deferred gains/(losses) on settled hedges, net	(27)			(27)
Currency translation adjustment		165		165
Proportionate share of our unconsolidated entities other comprehensive loss			(1)	(1)
Total period activity	(107)	165	(1)	57
Balance, September 30, 2009	$ 54	$ 79	$ (1)	$ 132

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.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. We are also engaged in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. See Note 13.

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 (SEC). 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 nine months ended September 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 November 6, 2009 and have been included within the following footnotes where applicable.

Note 2 Recent Accounting Pronouncements

Standards Adopted as of July 1, 2009

In June 2009, the Financial Accounting Standards Board (FASB) issued the FASB Accounting Standards Codification (the Codification) to establish a single source of authoritative nongovernmental U.S. generally accepted accounting principles (U.S. GAAP). The Codification is meant to (i) simplify user access by codifying all authoritative U.S. GAAP into one location, (ii) ensure that codified content accurately represents authoritative U.S. GAAP and (iii) create a better structure and research system for U.S. GAAP. The Codification was effective for interim or annual periods ending after September 15, 2009; therefore, we adopted this guidance as of July 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

Standards Adopted as of April 1, 2009

In May 2009, the FASB issued guidance that 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 guidance 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 guidance was effective for interim or annual periods ending after June 15, 2009; therefore, we adopted this guidance 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 guidance that 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 adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

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Standards Adopted as of January 1, 2009

In November 2008, the FASB issued guidance that 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 adopted this guidance 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 guidance that 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 previous guidance over goodwill and other intangible assets. The intent of this guidance is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset under U.S. GAAP. We adopted this guidance 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 FASB issued guidance that addresses the application of the two-class method in determining income per unit for master limited partnerships (MLPs) having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to participation rights in undistributed earnings. We adopted this guidance as of January 1, 2009. This guidance 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 7 for additional disclosure.

Note 3 Trade Accounts Receivable

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At September 30, 2009 and December 31, 2008, substantially all of our net accounts receivable were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $9 million and $5 million at September 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.

At September 30, 2009 and December 31, 2008, we had received approximately $153 million and $66 million, respectively, of advance cash payments from third parties to mitigate credit and performance 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 and performance risk.

Note 4 Acquisitions

The following acquisitions were accounted for using the acquisition method of accounting and the purchase price was allocated in accordance with such method.

PNGS Acquisition

On September 3, 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (PNGS) for an aggregate purchase price of $215 million (PNGS Acquisition). As a result of the transaction, we now own 100% of PNGS natural gas storage business and related operating entities, which are accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PNGS under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PNGS to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

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PNGS owns and operates a total of approximately 40 billion cubic feet (Bcf) of natural gas storage capacity at its Bluewater facility in Michigan and Pine Prairie facility in Louisiana. The Bluewater facility is comprised of two separate Niagaran reef reservoirs with a capacity of approximately 26 Bcf. At the Pine Prairie facility, 14 Bcf of high-deliverability salt-cavern storage capacity has been placed in service and an additional 10 Bcf is under construction. Pine Prairie Energy Center, LLC has received approvals from the Federal Energy Regulatory Commission and the Louisiana Department of Natural Resources to increase the permitted capacity at Pine Prairie to 48 Bcf. The gas storage operations are reflected in our facilities segment.

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

Cash	$	90
PAA equity		91
Paid at closing		181
Fair value of contingent consideration (1)		34
Total purchase price	$	215

(1) The deferred contingent cash consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of the deferred contingent cash consideration was based on a discounted cash flow model utilizing a discount rate of approximately 9%.

The allocation of fair value to the assets and liabilities acquired in the PNGS Acquisition is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired. The preliminary fair value allocation is as follows (in millions):

Property, plant and equipment	$	791
Base gas		28
Goodwill		26
Intangible assets		23
Working capital and other long-term assets and liabilities		8
Debt		(446)
Total	$	430

Other Acquisitions

During the first nine months of 2009, we completed three other acquisitions for aggregate consideration of approximately $66 million. These acquisitions included (i) a crude oil pipeline that is reflected in the our transportation segment, (ii) a natural gas processing business that is reflected in our facilities segment and (iii) a refined products terminal that is reflected in our facilities segment. In connection with these transactions, we allocated approximately $9 million to goodwill.

In October 2009, we completed an acquisition for approximately $40 million. The assets acquired include six crude oil storage tanks (with a total of approximately 400,000 barrels of storage capacity), three receiving pipelines, a manifold system and various other related assets in Tulsa, Oklahoma. In conjunction with this acquisition, the seller entered into a 15-year tank lease and minimum throughput agreement with us (with options to extend the lease and throughput agreement).

Note 5 Inventory, Linefill and Base Gas and Long-term Inventory

Inventory, linefill and base gas and long-term inventory consisted of the following (barrels in thousands and cubic feet in millions, and total value in millions):

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	September 30, 2009				December 31, 2008			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	12,418	barrels	$ 822	$ 66.19	9,986	barrels	$ 421	$ 42.16
LPG	9,252	barrels	340	$ 36.75	7,748	barrels	370	$ 47.75
Refined products	128	barrels	9	$ 70.31	103	barrels	5	$ 48.54
Natural gas (2)	244	cubic feet	1	$ 3.74		cubic feet		N/A
Parts and supplies	N/A		2	N/A	N/A		5	N/A
Inventory subtotal			1,174				801	
Linefill and base gas								
Crude oil	9,190	barrels	449	$ 48.86	9,148	barrels	422	$ 46.13
Natural gas (2) (3)	9,194	cubic feet	28	$ 3.03		cubic feet		N/A
LPG	58	barrels	2	$ 34.48	67	barrels	3	$ 44.78
Linefill and base gas			479				425	
Long-term inventory								
Crude oil	1,651	barrels	113	$ 68.44	1,781	barrels	121	$ 67.94
LPG	458	barrels	16	$ 34.93	363	barrels	18	$ 49.59
Long-term inventory subtotal			129				139	
Total			$ 1,782				$ 1,365	

(1) Price per unit represents a weighted average associated with various grades, qualities, and locations; accordingly, these prices may not be comparable to published benchmarks for such products.

(2) To account for the 6:1 mcf of natural gas to crude oil barrel ratio, the natural gas volumes can be converted to barrels by dividing by 6.

(3) Natural gas-base gas consists of natural gas necessary to operate our storage facilities and may fluctuate based on the utilization of the caverns and reservoirs.

Note 6 Debt

Debt consists of the following (in millions):

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	September 30, 2009	December 31, 2008
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.0% and 2.3% as of September 30, 2009 and December 31, 2008, respectively	$ 100	$ 280
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% and 1.1% as of September 30, 2009 and December 31, 2008, respectively (1)	336	746
Senior notes, including unamortized premium (2) (3)	255	
Other	1	1
Total short-term debt	692	1,027
Long-term debt:		
4.75% senior notes due August 2009 (4)		175
4.25% senior notes due September 2012 (5)	500	
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
7.13 % senior notes due June 2014 (3)		250
5.25% senior notes due June 2015	150	150
6.25% senior notes due September 2015	175	175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	
5.75% senior notes due January 2020	500	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(15)	(6)
Long-term debt under credit facilities and other (1)	7	40
Total long-term debt (1) (2)	4,142	3,259
Total debt	$ 4,834	$ 4,286

(1) As of September 30, 2009 and December 31, 2008, we have classified $336 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 fixed rate senior notes have a face value of approximately $4.4 billion as of September 30, 2009. We estimate the aggregate fair value of these notes as of September 30, 2009 to be approximately $4.7 billion. 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.

(3) On September 4, 2009, we gave irrevocable notice to redeem all of our outstanding $250 million 7.13% senior notes due 2014. After the 30-day notice period, the notes were redeemed on October 5, 2009. Therefore, these notes (including the unamortized premium) are classified as short-term debt on our balance sheet. In conjuction with the early redemption, we will recognize a loss of approximately $4 million.

(4) We repaid our $175 million 4.75% senior notes on August 15, 2009.

(5) These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility. At September 30, 2009, approximately $437 million had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

Senior Notes

In September 2009, we completed the issuance of $500 million of 5.75% senior notes due January 15, 2020. The senior notes were sold at 99.523% of face value. Interest payments are due on January 15 and July 15 of each year, beginning on January 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS Acquisition (which included repayment of all of PNGS s debt). See Note 4 for further discussion of the PNGS Acquisition.

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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.

Credit Facilities

In October 2009, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2010. The new committed facility replaced a similar $525 million facility that was scheduled to mature on November 5, 2009. The new facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion, subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance the purchase of hedged crude oil inventory for storage activities as well as for foreign import activities.

Letters of Credit

In connection with our crude oil marketing, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At September 30, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $66 million and $51 million, respectively.

Note 7 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 guidance issued by the FASB on the application of the two-class method for MLPs, 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 this guidance resulted in a change to our calculation of earnings per unit by using distributions applicable to the period rather than distributions paid in the period (applicable to the previous period). Also, in accordance with this guidance, earnings per unit for prior periods were recast to conform to this revised calculation.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2009 and 2008 (amounts in millions, except per unit data):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 122	$ 206	$ 469	$ 339
Less: General partner s incentive distribution paid (1)	(32)	(30)	(92)	(78)
Subtotal	90	176	377	261
Less: General partner 2% ownership (1)	(2)	(3)	(7)	(5)
Net income available to limited partners	88	173	370	256
Adjustment in accordance with application of the two-class method for MLPs (1)	(3)	2	(8)	(5)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 85	$ 175	$ 362	$ 251
Denominator:				
Basic weighted average number of limited partner units outstanding	130	123	128	120
Effect of dilutive securities:				
Weighted average LTIP units (2)	1	1	1	1
Diluted weighted average number of limited partner units outstanding	131	124	129	121
Basic net income per limited partner unit	$ 0.65	$ 1.42	$ 2.84	$ 2.10
Diluted net income per limited partner unit	$ 0.65	$ 1.41	$ 2.82	$ 2.08

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(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). Guidance issued by the FASB requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. We reflect the impact of this difference as the Adjustment in accordance with application of the two-class method for MLPs.

(2) Our LTIP awards (described in Note 9) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. 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 guidance issued by the FASB.

Note 8 Partners Capital and Distributions

Equity Offerings

During the nine months ended September 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						
September 2009	5,290,000	$ 46.70	$ 247	$ 5	$ (6)	$ 246
March 2009	5,750,000	$ 36.90	212	4	(6)	210
	11,040,000		**$ 459**	**$ 9**	**$ (12)**	**$ 456**
2008						
April 2008	6,900,000	$ 46.31	$ 320	$ 6	$ (11)	$ 315

(1) Costs include the gross spread paid to underwriters.

PNGS Acquisition

In September 2009, we issued 1,907,305 common units valued at approximately $91 million in order to satisfy a portion of the PNGS Acquisition purchase price. In conjunction with the issuance, we received a contribution from our general partner of approximately $2 million. See Note 4 for further discussion.

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 pertaining to the first nine months of 2009 and 2008, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid	Common Units Holders	Distributions Paid General Partner Incentive	Distributions Paid General Partner 2%	Total	Distributions per limited partner unit
2009						
October 19, 2009	November 13, 2009 (1)	$ 125	$ 35	$ 3	$ 163	$ 0.9200
July 15, 2009	August 14, 2009	$ 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						
October 22, 2008	November 14, 2008	$ 110	$ 28	$ 2	$ 140	$ 0.8925
July 14, 2008	August 14, 2008	$ 109	$ 30	$ 2	$ 141	$ 0.8875
April 17, 2008	May 15, 2008	$ 100	$ 25	$ 2	$ 127	$ 0.8650
January 16, 2008	February 14, 2008	$ 99	$ 23	$ 2	$ 124	$ 0.8500

(1) Payable to unitholders of record on November 3, 2009, for the period July 1, 2009 through September 30, 2009.

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Upon closing of the Pacific acquisition in November 2006 and the Rainbow acquisition in May 2008, our general partner agreed to reduce the amounts due it as incentive distributions. Additionally, in order to enhance our distribution coverage ratio over the next 24 months in connection with the PNGS Acquisition, our general partner has agreed to further reduce its incentive distributions by an aggregate of $8 million over the next two years - $1.25 million per quarter for the first four quarters and $0.75 million per quarter for the next four quarters. This incentive distribution reduction will become effective upon payment of our November 2009 quarterly distribution of $0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $83 million. Following the distribution in November 2009, the aggregate incentive distribution reductions remaining will be approximately $23 million.

Note 9 Equity Compensation Plans

Long-Term Incentive Plans

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

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date				
		2009	2010	2011	2012	2013
0.6(1)	$3.20		0.6			
1.5(2)	$3.50 - $4.50		0.1	0.8	0.5	0.1
1.7(3)	$3.50 - $4.25		0.8	0.3	0.4	0.2
3.8(4) (5)			1.5	1.1	0.9	0.3

(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 $4.25. For a majority of these LTIP awards, fifty percent will vest at specified dates regardless of whether the performance conditions are attained. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(4) Approximately 2 million of our approximately 3.8 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	0.5	$	31.18
Vested	(0.6)	$	34.70
Cancelled or forfeited	(0.1)	$	38.55
Acquired (1)	0.1	$	26.24
Outstanding, September 30, 2009	3.8	$	36.29

(1) As a result of the PNGS Acquisition, LTIP awards that were granted to PNGS employees in prior years are now included in our consolidated outstanding LTIP awards.

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Our accrued liability at September 30, 2009 related to all outstanding LTIP awards and DERs is approximately $70 million, which includes an accrual associated with our assessment that an annualized distribution of $3.90 is probable of occurring (at this time, we have not deemed a distribution of more than $3.90 to be probable). At December 31, 2008, the accrued liability was approximately $55 million.

Class B Units of Plains AAP, L.P.

At September 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 nine months ended September 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 September 30, 2009 was approximately $36 million of which approximately $1 million and $3 million was recognized as expense during the three months and nine months ended September 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 our equity compensation plans (in millions):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009		2008		2009		2008	
Equity compensation expense	$	16	$	3	$	47	$	27
LTIP unit vestings	$	1	$		$	19	$	1
LTIP cash settled vestings	$		$		$	7	$	2
DER cash payments	$	1	$	1	$	3	$	3

Based on the September 30, 2009 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $53 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 $46.29 at September 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)	$	9
2010		26
2011		12
2012		5
2013		1

Total	$	53

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

Note 10 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and utilize risk management strategies 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

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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. 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, refined products 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 September 30, 2009, material net derivative positions related to these activities included:

- An approximate 195,000 barrel per day net long position (total of 5.9 million barrels) associated with our crude oil activities, which was unwound ratably during October 2009 to match monthly average pricing.

- An approximate 31,000 barrel per day (total of 13 million barrels) net short spread position which hedge a portion of our anticipated crude oil lease gathering purchases through November 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).

- A net short position averaging approximately 14,500 barrels per day (total of 6.1 million barrels) of calendar spread call options for the period November 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 3,100 barrels per day (total of 1.4 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 17,100 barrels per day on average (total of 7.7 million barrels) of crude oil basis differential hedges, which run through 2010.

Storage Capacity Utilization We own approximately 57 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 September 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 September 30, 2009, we had approximately 9.5 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 September 30, 2009, we had approximately 4 million barrels of foreign cargo inventory hedged with

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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 September 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 1.9 million barrels) from October 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 pipeline operations and have used derivative instruments to hedge the anticipated forward purchases of diluent and diluent inventory. As of September 30, 2009, we had an average of 4,700 barrels per day of natural gasoline/WTI spread positions (approximately 3 million barrels) that run through mid-2011 and an average of 4,400 barrels per day of short crude oil futures (approximately 0.8 million barrels) to hedge condensate through the first quarter of 2010.

Natural Gas Purchases Our gas storage facilities require minimum levels of natural gas (base gas) to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge anticipated purchases of natural gas. As of September 30, 2009, we have a net long position of approximately 3 Bcf consisting of natural gas futures contracts through August 2010.

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 normal sale (NPNS) exclusion and thus are not subject to the accounting treatment for derivative instruments and hedging activities as set forth in FASB guidance. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception 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 September 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 derivatives 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 September 30, 2009, we had four outstanding interest rate swaps by which we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an aggregate spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminate in 2011 and two of the swaps terminate in 2012.

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 (USD)-to-Canadian Dollar (CAD) exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments primarily include forward exchange contracts and foreign currency forwards and options. As of September 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 CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the foreign exchange rate.

As of September 30, 2009, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative we enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

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At September 30, 2009, our open foreign exchange derivatives consisted of forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2009	$ 18	$ 15	CAD $1.15 to US $1.00
2010	$ 43	$ 39	CAD $1.14 to US $1.00
2011	$ 15	$ 15	CAD $1.01 to US $1.00
2012	$ 15	$ 15	CAD $1.01 to US $1.00
2013	$ 9	$ 9	CAD $1.00 to US $1.00

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

Summary of Financial Impact

The majority of our derivative activity relates to our commodity price risk hedging activities. 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 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 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 nine months ended September 30, 2009 is as follows (in millions, losses designated in parentheses):

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DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS:

Three Months Ended September 30, 2009:

		Derivatives in Cash Flow Hedging Relationships						
	Location of gain/(loss)		**AOCI Reclass (1)**		**Inneffective Portion (2)**		**Derivatives Not Designated as a Hedge (3)**	**Total**
Commodity contracts	Sales and related revenues	$	(159)	$	2	$	11	$ (146)
	Purchases and related costs		60				4	64
Interest Rate Contracts	Interest expense						1	1
Foreign Exchange Contracts	Sales and related revenues						4	4
	Purchases and related costs						2	2
	Other income/(expense), net						(1)	(1)
Total Gain/(Loss) Recognized in Income from Derivatives		**$**	**(99)**	**$**	**2**	**$**	**21**	**$ (76)**

(1) Amounts represent derivative gains and (losses) that were reclassed from AOCI to earnings during the period to coincide with earnings impact of the respective hedged transaction

(2) Amounts represent the ineffective portion of the fair value of our unrealized cash flow hedges that was recognized in earnings during the period.

(3) Amounts include the mark-to-market earnings impact for unrealized derivatives not designated for hedge accounting during the period.

Nine Months Ended September 30, 2009:

		Derivatives in Cash Flow Hedging Relationships						
	Location of gain/(loss)		**AOCI Reclass (1)**		**Inneffective Portion (2)**		**Derivatives Not Designated as a Hedge (3)**	**Total**
Commodity contracts	Sales and related revenues	$	(14)	$	(6)	$	17	$ (3)
	Purchases and related costs		29				119	148
	Other income/(expense), net						(1)	(1)

Interest Rate Contracts					
	Interest expense	(1)		1	
Foreign Exchange Contracts	Sales and related revenues			9	9
	Purchases and related costs			(1)	(1)
	Other income/(expense), net	5		(3)	2
Total Gain/(Loss) Recognized in Income from Derivatives		**$ 19**	**$ (6)**	**$ 141**	**$ 154**

(1) Amounts represent derivative gains and (losses) that were reclassed from AOCI to earnings during the period to coincide with earnings impact of the respective hedged transaction

(2) Amounts represent the ineffective portion of the fair value of our unrealized cash flow hedges that was recognized in earnings during the period.

(3) Amounts include the mark-to-market earnings impact for unrealized derivatives not designated for hedge accounting during the period.

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet as of September 30, 2009 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity contracts	Other current assets	$	77	Other current liabilities	$	(97)
	Other long-term assets		48	Other long-term liabilities		(3)
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		(2)
	Other long-term assets		2	Other long-term liabilities		(1)
Total derivatives designated as hedging instruments		$	128		$	(103)
Derivatives not designated as hedging instruments:						
Commodity contracts	Other current assets	$	80	Other current liabilities	$	(58)
	Other long-term assets		46	Other long-term liabilities		(39)
Interest rate contracts	Other current assets		1	Other current liabilities		
	Other long-term assets		1	Other long-term liabilities		
Foreign exchange contracts	Other current assets		3	Other current liabilities		(1)
	Other long-term assets			Other long-term liabilities		
Total derivatives not designated as hedging instruments		$	131		$	(98)
Total derivatives		$	259		$	(201)

As of September 30, 2009, there was a net gain of $54 million deferred in AOCI. The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the related physical purchase or delivery of the underlying commodity, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany interest receivables. Of the total net gain deferred in AOCI at September 30, 2009, a net gain of approximately $1 million is expected to be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 74% is expected to be reclassified to earnings prior to 2012 with the remaining deferred gain being reclassified to earnings through 2019. 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 September 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 nine months ended September 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 nine months ended September 30, 2008, no amounts were reclassed from AOCI as a result of anticipated hedge transactions that were no longer considered to be probable of occurring.

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

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Commodity contracts	$ 4	$ (79)
Foreign exchange contracts	(5)	(7)
Interest rate contracts	(2)	(2)
Total	$ (3)	$ (88)

We do not enter into master netting agreements with our over-the-counter 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

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margin. We did not have a broker receivable as of September 30, 2009. Our broker receivable was approximately $81 million as of December 31, 2008. At September 30, 2009 and December 31, 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 September 30, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of September 30, 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	$ 230	$	$ 21	$ 251	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives			2	2			5	5
Foreign currency derivatives			6	6			18	18
Total assets at fair value	$ 230	$	$ 29	$ 259	$ 235	$ 9	$ 135	$ 379
Liabilities:								
Commodity derivatives	$ (159)	$	$ (38)	$ (197)	$ (330)	$	$ (56)	$ (386)
Foreign currency derivatives			(4)	(4)			(5)	(5)
Total liabilities at fair value	$ (159)	$	$ (42)	$ (201)	$ (330)	$	$ (61)	$ (391)
Net asset/(liability) at fair value	$ 71	$	$ (13)	$ 58	$ (95)	$ 9	$ 74	$ (12)

The determination of the fair values above 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 exchange-traded commodity derivatives 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 as of December 31, 2008 is a physical commodity supply contract that meets the definition of a derivative, but is not excluded under the NPNS 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 commodity 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.

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

The majority of our level 3 derivatives are classified as such 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 level 3 derivatives (in millions):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Beginning Balance	$ (5)	$ (56)	$ 74	$ (21)
Realized and unrealized gains/(losses):				
Included in earnings	3	36	57	(45)
Included in other comprehensive income	(10)	7	(32)	5
Purchases, issuances, sales and settlements	(1)	26	(112)	74
Transfers into or (out of) level 3				
Ending Balance	$ (13)	$ 13	$ (13)	$ 13
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$	$ 62	$ (8)	$ 34

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

Note 11 Income Taxes

U.S. Federal and State Taxes

As an MLP, 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. Additionally, in December 2008, the Fifth Protocol to the U.S./Canada Tax Treaty was ratified and contained language that increases the withholding tax on dividends and intercompany interest effective in 2010. As a result of these collective changes, we are evaluating a number of alternatives to restructure our Canadian subsidiaries to optimize both entity and equity owner level taxes. We anticipate effecting any structural changes in 2010 or early 2011.

Note 12 Commitments and Contingencies

Litigation

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late

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December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $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 $23 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 are underway.

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 $10 million. Both Exxon and GATX were prior owners of the terminal. We contend that Exxon and GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. 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

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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 (pre- and post-merger) 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 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.

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 September 30, 2009, our reserve for environmental liabilities totaled approximately $48 million, of which approximately $11 million is classified as short-term and $37 million is classified as long-term. At September 30, 2009, we have recorded receivables totaling approximately $3 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.

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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.

Note 13 Operating Segments

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

	Transportation	Facilities	Marketing	Total
Three Months Ended September 30, 2009				
Revenues:				
External Customers	$ 147	$ 65	$ 4,645	$ 4,857
Intersegment (1)	103	32		135
Total revenues of reportable segments	$ 250	$ 97	$ 4,645	$ 4,992
Equity earnings in unconsolidated entities	$ 2	$ 3	$	$ 5
Segment profit(2) (3) (4)	$ 129	$ 57	$ 44	$ 230
Maintenance capital	$ 9	$ 2	$ 1	$ 12
Three Months Ended September 30, 2008				
Revenues:				
External Customers	$ 147	$ 39	$ 8,676	$ 8,862
Intersegment (1)	95	30		125
Total revenues of reportable segments	$ 242	$ 69	$ 8,676	$ 8,987
Equity earnings in unconsolidated entities	$ 1	$ 3	$	$ 4
Segment profit(2) (3) (4)	$ 119	$ 39	$ 138	$ 296
Maintenance capital	$ 13	$ 5	$ 1	$ 19
Nine Months Ended September 30, 2009				
Revenues:				
External Customers	$ 401	$ 165	$ 11,876	$ 12,442
Intersegment (1)	313	94	1	408
Total revenues of reportable segments	$ 714	$ 259	$ 11,877	$ 12,850
Equity earnings in unconsolidated entities	$ 5	$ 8	$	$ 13
Segment profit(2) (3) (4)	$ 355	$ 155	$ 282	$ 792
Maintenance capital	$ 40	$ 11	$ 5	$ 56
Nine Months Ended September 30, 2008				
Revenues:				

External Customers	$	416	$	109	$	24,593	$	25,118
Intersegment (1)		264		85		1		350
Total revenues of reportable segments	$	680	$	194	$	24,594	$	25,468
Equity earnings in unconsolidated entities	$	4	$	7	$		$	11
Segment profit(2) (3) (4)	$	315	$	107	$	190	$	612
Maintenance capital	$	38	$	15	$	3	$	56

(1) Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe

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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 $4 million and $6 million for the three months ended September 30, 2009 and 2008, respectively, and $8 million and $15 million for the nine months ended September 30, 2009 and 2008, respectively.

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

	For the Three Months Ended September 30, 2009	For the Three Months Ended September 30, 2008	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
Segment profit	$ 230	$ 296	$ 792	$ 612
Depreciation and amortization	(59)	(49)	(173)	(150)
Interest expense	(59)	(52)	(165)	(143)
Other income/(expense), net	12	14	17	27
Income tax expense	(2)	(3)	(1)	(7)
Net income	122	206	470	339
Less: Net (income) attributable to noncontrolling interest			(1)	
Net income attributable to Plains	$ 122	$ 206	$ 469	$ 339

Note 14 Supplemental Condensed Consolidating Financial Information

For purposes of this Note 14, Plains 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 a list of subsidiaries classified as Guarantor Subsidiaries and subsidiaries classified as Non-Guarantor Subsidiaries. As a result of the PNGS Acquisition, all PNGS subsidiaries are classified as Non-Guarantor Subsidiaries. There have been no other 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 September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,601	$ 3,196	$ 189	$ (3,962)	$ 3,024

Property, plant and equipment, net		4,486	1,711		6,197
Investment in unconsolidated entities	5,133	1,673		(6,738)	68
Other assets	30	2,208	391	(425)	2,204
Total assets	$ 8,764	$ 11,563	$ 2,291	$ (11,125)	$ 11,493
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 401	$ 6,160	$ 260	$ (3,962)	$ 2,859
Long-term debt	4,136	6	425	(425)	4,142
Other long-term liabilities		263	2		265
Total liabilities	4,537	6,429	687	(4,387)	7,266
Partners capital excluding noncontrolling interest	4,163	5,070	1,604	(6,674)	4,163
Noncontrolling interest	64	64		(64)	64
Total partners capital	4,227	5,134	1,604	(6,738)	4,227
Total liabilities and partners capital	$ 8,764	$ 11,563	$ 2,291	$ (11,125)	$ 11,493

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Condensed Consolidating Balance Sheet (continued)

	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 September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 396	$ 44	$	$ 440
Field operating costs		(150)	(13)		(163)
General and administrative expenses		(48)	(4)		(52)
Depreciation and amortization	(1)	(49)	(9)		(59)
Operating income/(loss)	(1)	149	18		166
Equity earnings in unconsolidated entities	184	19		(198)	5
Interest expense	(61)	3	(1)		(59)
Other income, net		12			12
Income tax expense		(2)			(2)
Net income	$ 122	$ 181	$ 17	$ (198)	$ 122

	Three Months Ended September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 467	$ 26	$	$ 493

Field operating costs		(151)	(11)		(162)
General and administrative expenses		(37)	(2)		(39)
Depreciation and amortization		(44)	(5)		(49)
Operating income		235	8		243
Equity earnings in unconsolidated entities	258	10		(264)	4
Interest expense	(52)				(52)
Other income, net		13	1		14
Income tax expense		(3)			(3)
Net income	$ 206	$ 255	$ 9	$ (264)	$ 206

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Condensed Consolidating Statements of Operations (continued)

	Nine Months Ended September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 1,296	$ 110	$	$ 1,406
Field operating costs		(442)	(32)		(474)
General and administrative expenses		(144)	(9)		(153)
Depreciation and amortization	(3)	(148)	(22)		(173)
Operating income/(loss)	(3)	562	47		606
Equity earnings in unconsolidated entities	642	51		(680)	13
Interest expense	(170)	6	(1)		(165)
Other income, net		17			17
Income tax expense		(1)			(1)
Net income	$ 469	$ 635	$ 46	$ (680)	$ 470
Less: Net income attributable to noncontrolling interest		(1)			(1)
Net income attributable to Plains	$ 469	$ 634	$ 46	$ (680)	$ 469

	Nine Months Ended September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 1,103	$ 86	$	$ 1,189
Field operating costs		(426)	(32)		(458)
General and administrative expenses		(121)	(9)		(130)
Depreciation and amortization	(2)	(133)	(15)		(150)
Operating income/(loss)	(2)	423	30		451
Equity earnings in unconsolidated entities	483	34		(506)	11
Interest expense	(143)				(143)
Other income, net	1	25	1		27
Income tax expense		(7)			(7)
Net income	$ 339	$ 475	$ 31	$ (506)	$ 339

(1) Net operating revenues are calculated as Total revenues less Purchases and related costs.

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Condensed Consolidating Statements of Cash Flows

	Nine Months Ended September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 469	$ 635	$ 46	$ (680)	$ 470
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	148	22		173
Equity compensation charge		46	1		47
Other	(638)	(85)		680	(43)
Changes in assets and liabilities, net of acquisitions	(826)	535	(9)		(300)
Net cash provided by (used in) operating activities	(992)	1,279	60		347
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired		(117)			(117)
Additions to property, equipment and other		(301)	(53)		(354)
Investment in unconsolidated entities	(4)				(4)
Cash received for sale of noncontrolling interest in a subsidiary		26			26
Net cash received for linefill		8			8
Proceeds from the sale of assets and other		4			4
Net cash used in investing activities	(4)	(380)	(53)		(437)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	(182)	(272)			(454)
Net repayments on hedged inventory facility		(180)			(180)
Repayment of PNGS debt		(446)			(446)
Proceeds from the issuance of senior notes	1,346				1,346
Repayments of senior notes	(175)				(175)
Proceeds from the issuance of common units	458				458
Distributions paid to common unitholders and general partner	(442)				(442)
Other financing activities	(9)				(9)
Net cash provided by (used in) financing activities	996	(898)			98
Effect of translation adjustment on cash		(3)			(3)
Net increase/(decrease) in cash and cash equivalents		(2)	7		5
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 2	$ 7	$ 7	$	$ 16

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Condensed Consolidating Statements of Cash Flows (continued)

	Nine Months Ended September 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 339	$ 475	$ 31	$ (506)	$ 339
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	2	133	15		150
Equity compensation expense		27			27
Other	(478)	(62)		506	(34)
Changes in assets and liabilities, net of acquisitions	(307)	92	(28)		(243)
Net cash provided by operating activities	(444)	665	18		239
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired		(662)			(662)
Additions to property, equipment and other		(428)	(18)		(446)
Investment in unconsolidated entities	(35)				(35)
Net cash paid for linefill		(8)			(8)
Proceeds from the sale of assets and other		36			36
Net cash used in investing activities	(35)	(1,062)	(18)		(1,115)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		259			259
Net repayments on hedged inventory facility		111			111
Proceeds from the issuance of senior notes	597				597
Net proceeds from the issuance of common units	315				315
Distributions paid to common unitholders and general partner	(392)				(392)
Other financing activities	(4)				(4)
Net cash provided by financing activities	516	370			886
Effect of translation adjustment on cash		3			3
Net increase/(decrease) in cash and cash equivalents	37	(24)			13
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ 38	$ (1)	$	$	$ 37

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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
- Acquisitions and Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements and Associated Risks

Overview of Operating Results, Capital Spending and Significant Activities

During the first nine months of 2009, all three of our segments provided favorable operating results, particularly our marketing segment, which benefited from the favorable contango crude oil market structure early in the period and favorable LPG margins. Additional key items impacting the first nine months of 2009 include:

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

- One months contribution to earnings from the September 2009 acquisition of the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (PNGS) from Vulcan Gas Storage LLC (Vulcan), as well as increased earnings resulting from prior acquisitions and expansion projects included in our facilities segment.

- Equity compensation plan expense of approximately $47 million for the nine months of 2009 compared to $27 million for the corresponding prior year period. The increased expense primarily resulted from an increase in unit price for the first nine months of 2009 compared to a decrease in unit price for the first nine 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, and the issuance of 5,290,000 limited partner units at $46.70 per unit for net proceeds of approximately $246 million in September 2009.

- In September 2009, we issued 1,907,305 common units valued at approximately $91 million in order to satisfy a portion of the PNGS Acquisition purchase price. In conjunction with the issuance, we received a contribution from our general partner of approximately $2 million. See Note 4 to the Condensed Consolidated Financial Statements for further discussion.

- The issuance and repayment of the following senior notes:

  - Issuance of $350 million of 8.75% senior notes for net proceeds of approximately $347 million in April 2009.

  - Issuance of $500 million of 4.25% senior notes for net proceeds of approximately $497 million in July 2009.

  - Repayment of $175 million of 4.75% senior notes in August 2009.

  - Issuance of $500 million of 5.75% senior notes for net proceeds of approximately $494 million in September 2009.

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Acquisitions and Internal Growth Projects

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Acquisition capital	$ 281	$ 688
Internal growth projects	261	379
Maintenance capital	56	56
Investment in unconsolidated entities	4	35
Total	$ 602	$ 1,158

Acquisitions

PNGS Acquisition

On September 3, 2009, we acquired the remaining 50% interest in PNGS from Vulcan for an aggregate purchase price of $215 million. The gas storage operations are reflected in our facilities segment. See Note 4 to our Condensed Consolidated Financial Statements for further discussion of the purchase price and related allocation.

Other Acquisitions

During 2009, we completed three other acquisitions for aggregate consideration of approximately $66 million. These acquisitions included (i) a crude oil pipeline that is reflected in the our transportation segment, (ii) a natural gas processing business that is reflected in our facilities segment, and (iii) a refined products terminal that is reflected in our facilities segment. In connection with these transactions, we allocated approximately $9 million to goodwill.

In October 2009, we completed an acquisition for approximately $40 million. The assets acquired include six crude oil storage tanks (with a total of approximately 400,000 barrels of storage capacity), three receiving pipelines, a manifold system and various other related assets in Tulsa, Oklahoma. In conjunction with this acquisition, the seller entered into a 15-year tank lease and minimum throughput agreement with us (with options to extend the lease and throughput agreement).

Internal Growth Projects

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

Projects		**2009**
St. James Phase III (1)		73
Rangeland tankage and connections		35
Kerrobert pumping project		34
Cushing Phase VII		29
Patoka Phase II & III		20
Nipisi storage and truck terminal		20
Pier 400		18
Pine Prairie		15
Salt Lake City		14
Paulsboro tankage		12
Other projects, including acquisition related expansion projects (2)		110
Total	$	380

(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.

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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 September 30,		Three Months Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Nine Months Favorable/ (Unfavorable) Variance	
	2009	2008	$	%	2009	2008	$	%
Transportation segment profit	$ 129	$ 119	$ 10	8%	$ 355	$ 315	$ 40	13%
Facilities segment profit	57	39	18	46%	155	107	48	45%
Marketing segment profit	44	138	(94)	(68)%	282	190	92	49%
Total segment profit	230	296	(66)	(22)%	792	612	180	29%
Depreciation and amortization	(59)	(49)	(10)	(20)%	(173)	(150)	(23)	(15)%
Interest expense	(59)	(52)	(7)	(13)%	(165)	(143)	(22)	(15)%
Other income/(expense), net	12	14	(2)	(14)%	17	27	(10)	(37)%
Income tax expense	(2)	(3)	1	33%	(1)	(7)	6	86%
Net income	122	206	(84)	(41)%	470	339	131	39%
Less: Net (income) attributable to noncontrolling interest				%	(1)		(1)	100%
Net income attributable to Plains	$ 122	$ 206	$ (84)	(41)%	$ 469	$ 339	$ 130	38%
Earnings per basic limited partner unit	$ 0.65	$ 1.42	$ (0.77)	(54)%	$ 2.84	$ 2.10	$ 0.74	35%
Earnings per diluted limited partner unit	$ 0.65	$ 1.41	$ (0.76)	(54)%	$ 2.82	$ 2.08	$ 0.74	36%
Basic weighted average units outstanding	130	123	7	6%	128	120	8	7%
Diluted weighted average units outstanding	131	124	7	6%	129	121	8	7%

Transportation Segment

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

Operating Results (1)	Three Months Ended September 30,	Three Months Favorable/ (Unfavorable) Variance	Nine Months Ended September 30,	Nine Months Favorable/ (Unfavorable) Variance

(in millions, except per barrel amounts)	2009	2008	$	%	2009	2008	$	%
Revenues								
Tariff activities	$ 228	$ 209	$ 19	9%	$ 644	$ 583	$ 61	10%
Trucking	22	33	(11)	(33)%	70	97	(27)	(28)%
Total transportation revenues	250	242	8	3%	714	680	34	5%
Costs and Expenses								
Trucking costs	(15)	(23)	8	35%	(47)	(68)	21	31%
Field operating costs (excluding equity compensation (expense))/benefit	(86)	(86)		%	(249)	(246)	(3)	(1)%
Equity compensation (expense)/benefit operations (2)	(2)	1	(3)	300%	(6)	(1)	(5)	(500)%
Segment G&A expenses (excluding equity compensation expense)	(14)	(14)		%	(45)	(42)	(3)	(7)%
Equity compensation expense - general and administrative (2)	(6)	(2)	(4)	(200)%	(17)	(12)	(5)	(42)%
Equity earnings in unconsolidated entities	2	1	1	100%	5	4	1	25%
Segment profit	$ 129	$ 119	$ 10	8%	$ 355	$ 315	$ 40	13%
Maintenance capital	$ 9	$ 13	$ 4	31%	$ 40	$ 38	$ (2)	(5)%
Segment profit per barrel	$ 0.48	$ 0.44	$ 0.04	9%	$ 0.44	$ 0.39	$ 0.05	13%

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Average Daily Volumes	Three Months Ended September 30,		Three Months Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Nine Months Favorable/ (Unfavorable) Variance	
(in thousands of barrels per day) (3)	2009	2008	Volumes	%	2009	2008	Volumes	%
Tariff activities								
All American	43	44	(1)	(2)%	40	44	(4)	(9)%
Basin	335	375	(40)	(11)%	389	372	17	5%
Capline	205	216	(11)	(5)%	205	218	(13)	(6)%
Line 63/Line 2000	141	131	10	8%	136	151	(15)	(10)%
Salt Lake City Area Systems	152	90	62	69%	132	94	38	40%
West Texas/New Mexico Area Systems	355	370	(15)	(4)%	375	367	8	2%
Manito	62	68	(6)	(9)%	62	70	(8)	(11)%
Rainbow	176	191	(15)	(8)%	184	108	76	70%
Rangeland	51	54	(3)	(6)%	54	58	(4)	(7)%
Refined products	100	108	(8)	(7)%	96	110	(14)	(13)%
Other	1,219	1,234	(15)	(1)%	1,207	1,238	(31)	(3)%
Tariff activities total	2,839	2,881	(42)	(1)%	2,880	2,830	50	2%
Trucking	80	101	(21)	(21)%	84	96	(12)	(13)%
Transportation segment total	2,919	2,982	(63)	(2)%	2,964	2,926	38	1%

(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 nine months ended September 30, 2009 were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues increased and volumes were relatively flat for both the three and nine months ended September 30, 2009 compared to the three and nine months ended September 30, 2008. The significant variances in revenues and average daily volumes between the comparative periods are discussed below:

- Acquisitions The Rainbow acquisition was effective May 1, 2008 and contributed additional volumes of 76,000 barrels per day and approximately $13 million of additional tariff revenues (net of the resolution of tariff disputes) during the nine months ended September 30, 2009 relative to the same period of 2008.

- Expansion Activities In the fourth quarter of 2008, we completed construction of a 93-mile expansion of the Salt Lake City Core Area system from Wahsatch, Utah to Salt Lake City. This line expansion, which was placed into service during the first quarter of 2009, contributed additional revenues for the three and nine months ended September 30, 2009 of approximately $4 million and $9 million, respectively.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the 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 $12 million for the three and nine months ended September 30, 2009 compared to the three and nine months ended September 30, 2008.

- Trucking Revenues and volumes from trucking decreased for the three and nine months ended September 30, 2009 compared to the three and nine months ended September 30, 2008 primarily related to a decrease in demand.

- Rate increases Rates increased on certain of our pipeline systems after the second quarter of 2008 and 2009 as a result of indexing by the Federal Energy Regulation Commission (FERC). In addition, we had similar type rate increases on non-FERC regulated pipelines

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resulted in increased revenues for the three and nine months ended September 30, 2009 compared to the three and nine months ended September 30, 2008.

Equity Compensation Charges. Equity compensation charges increased in 2009 compared to 2008 primarily as a result of an increase in unit price for the nine-month period ended September 30, 2009 compared to a decrease in unit price for the nine-month period ended September 30, 2008. See Note 9 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:

Operating Results (1) (in millions, except per barrel amounts)	**Three Months Ended September 30, 2009**	**2008**	**Three Months Favorable/ (Unfavorable) Variance $**	**%**	**Nine Months Ended September 30, 2009**	**2008**	**Nine Months Favorable/ (Unfavorable) Variance $**	**%**
Storage and terminalling revenues (1)	$ 97	$ 69	$ 28	41%	$ 259	$ 194	$ 65	34%
Purchases and related costs	(1)		(1)	N/A	(1)		(1)	N/A
Field operating costs	(32)	(27)	(5)	(19)%	(85)	(76)	(9)	(12)%
Segment G&A expenses (excluding equity compensation expense)	(7)	(5)	(2)	(40)%	(18)	(13)	(5)	(38)%
Equity compensation expense - general and administrative (2)	(3)	(1)	(2)	(200)%	(7)	(5)	(2)	(40)%
Equity earnings in unconsolidated entities	3	3		%	8	7	1	14%
Segment profit	$ 57	$ 39	$ 18	46%	$ 156	$ 107	$ 49	46%
Maintenance capital	$ 2	$ 5	$ 3	60%	$ 11	$ 15	$ 4	27%
Segment profit per barrel	$ 0.31	$ 0.23	$ 0.08	35%	$ 0.29	$ 0.21	$ 0.08	38%

Volumes (3)(4)	**Three Months Ended September 30, 2009**	**2008**	**Three Months Favorable/ (Unfavorable) Variance Volumes**	**%**	**Nine Months Ended September 30, 2009**	**2008**	**Nine Months Favorable/ (Unfavorable) Variance Volumes**	**%**
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	55	1	2%	56	54	2	4%
Natural gas storage (average monthly capacity in billions of cubic feet (bcf)) (5)	27	14	13	93%	21	13	8	62%
LPG processing (average throughput in thousands of barrels per day)	17	17		%	16	16		%

Facilities segment total (average monthly capacity in millions of barrels)	61	58	3	5%	60	57	3	5%

(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.

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(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 Mmcf 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.

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, Natural gas storage volumes for 2008 and January through August 2009 are netted to our 50% interest in PNGS. September 2009 volumes represent our 100% interest in PNGS.

Facilities segment profit and segment profit per barrel for the three and nine months ended September 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 nine months ended September 30, 2009 compared to the three and nine months ended September 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 aggregate increase in revenues of approximately $8 million and $24 million for the three and nine months ended September 30, 2009 compared to the same periods of 2008.

- Acquisitions Revenues and volumes for the three and nine months ended September 30, 2009 were impacted by the PNGS Acquisition, which closed during the third quarter of 2009 and the acquisition of a natural gas processing business, which closed during the second quarter of 2009. Revenues and volumes for the three and nine months ended September 20, 2009 compared to the same periods during 2008 were also impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008. Such acquisitions contributed approximately $12 million and $18 million in revenues for the three and nine months ended September 30, 2009 compared to the same periods of 2008, respectively.

- Leased Tankage Revenues for the three and nine months ended September 30, 2009 increased primarily as a result of general escalations on existing leases.

Field Operating Costs. Field operating costs (excluding equity compensation charges) have increased in several categories for the three and nine months ended September 30, 2009 in comparison to the three and nine months ended September 30, 2008 primarily related to the expansion projects and acquisitions discussed above. The 2009 increased cost categories included (i) payroll and benefits and (ii) property taxes, partially offset by a decrease in utilities costs.

G&A Costs. G&A costs (excluding equity compensation charges) have increased in most categories for the three and nine months ended September 30, 2009 in comparison to the three and nine months ended September 30, 2008 primarily related to the acquisitions discussed above. The 2009 increased cost categories included (i) payroll and benefits, (ii) legal fees and (iii) consulting and other fees related to our acquisition transactions.

Equity Compensation Charges. Equity compensation charges increased in 2009 compared to 2008 primarily as a result of an increase in unit price for the nine-month period ended September 30, 2009 compared to a decrease in unit price for the nine-month period ended September 30, 2008. See Note 9 to our Condensed Consolidated Financial Statements for additional information on our equity compensation plans.

Marketing Segment

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

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Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Three Months Favorable/(Unfavorable) Variance $	Three Months Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Nine Months Favorable/(Unfavorable) Variance $	Nine Months Favorable/(Unfavorable) Variance %
Revenues (2)	$ 4,645	$ 8,676	$ (4,031)	(46)%	$ 11,877	$ 24,594	$ (12,717)	(52)%
Purchases and related costs (2) (3)	(4,534)	(8,471)	3,937	46%	(11,389)	(24,211)	12,822	53%
Field operating costs	(45)	(50)	5	10%	(139)	(135)	(4)	(3)%
Equity compensation expense - operations (4)				%	(1)		(1)	%
Segment G&A expenses (excluding equity compensation expense)	(17)	(16)	(1)	(6)%	(51)	(49)	(2)	(4)%
Equity compensation expense - general and administrative (4)	(5)	(1)	(4)	(400)%	(15)	(9)	(6)	(67)%
Segment profit/(loss) (2)	$ 44	$ 138	$ (94)	68%	$ 282	$ 190	$ 92	48%
Maintenance capital	$ 1	$ 1	$		$ 5	$ 3	$ (2)	(67)%
Segment profit per barrel (5)	$ 0.65	$ 1.86	$ (1.21)	65%	$ 1.30	$ 0.81	$ 0.49	60%

Average Daily Volumes (6) (in thousands of barrels per day)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Three Months Favorable/(Unfavorable) Variance Volumes	Three Months Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Nine Months Favorable/(Unfavorable) Variance Volumes	Nine Months Favorable/(Unfavorable) Variance %
Crude oil lease gathering purchases	602	638	(36)	(6)%	619	663	(44)	(7)%
Refined products sales	32	27	5	19%	34	24	10	42%
LPG sales	61	67	(6)	(9)%	88	85	3	4%
Waterborne foreign crude oil imported	46	77	(31)	(40)%	54	84	(30)	(36)%
Marketing segment total	741	809	(68)	(8)%	795	856	(61)	(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 (related to hedged inventory purchases) of approximately $4 million and $8 million for the three and nine months ended September 30, 2009, respectively, compared to $6 million and $15 million for the three and nine months ended September 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.

Revenues and Purchases and Related Costs. The absolute amount of our revenues and purchases decreased in the three and nine months ended September 30, 2009 as compared to the three and nine months ended September 30, 2008, primarily resulting from lower commodity prices in the 2009 period. The NYMEX benchmark price of crude oil ranged from $59 to $75 per barrel and $91 to $147 per barrel during the three months ended September 30, 2009 and 2008, respectively, and from $34 to $75 per barrel and $86 to $147 per barrel during the nine months ended September 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 unfavorable variance between our net revenues and purchases for the three months ended September 30, 2009 as compared to the three months ended September 30, 2008, was primarily attributable to the following:

• *Mark-to-Market Gain and Inventory Valuation Adjustment* Revenues for the third quarter of 2008 include a net mark-to-market gain of approximately $163 million, a portion of which was offset by a lower of cost or market inventory valuation adjustment of approximately $65 million. The comparable 2009 period included a net mark-to-market gain of approximately $11 million. The $87 million increase in revenues for the 2008 period as compared to the 2009 period was primarily the result of the significant decrease in crude oil and LPG prices that occurred during the third quarter of 2008 that impacted the financial derivatives we were utilizing in our risk management strategies.

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- *LPG Marketing* Lower results from our LPG operations in the third quarter 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 negatively impacted the third quarter of 2009.

- *Crude Oil and Refined Products Marketing* Lower results from our gathering and marketing activities in the third quarter of 2009 as compared to the third quarter of 2008. The 2009 period was negatively impacted by tighter differentials and lower volumes of lease gathering crude oil purchases and waterborne foreign crude oil import barrels. The decrease in volumes was partially related to a change in methodology for reporting volumes and due to an ongoing effort to reduce low margin barrels.

These unfavorable variances were partially offset by the favorable impact of:

- *Contango Market Structure* We benefited in the third quarter of 2009 from a stronger contango market structure compared to that in the third quarter of 2008. The market structure for the third quarter of 2009 and 2008 averaged approximately $1.15 per barrel contango and approximately $0.42 per barrel contango, respectively.

The favorable variance between our net revenues and purchases for the nine months ended September 30, 2009 as compared to the nine months ended September 30, 2008, was primarily attributable to the following:

- *Contango Market Structure* The favorable impact of a strong contango market on earnings in the early part of 2009, while the corresponding market conditions during the first nine months of 2008 were slightly backwardated. The market structure for the first nine months of 2009 averaged approximately $1.81 per barrel contango. The market structure averaged approximately $0.18 per barrel backwardated for the first nine months of 2008.

- *LPG Marketing* Higher results from our LPG operations in the first nine months of 2009 as compared to the respective period in 2008 primarily related to the timing of recognizing fixed price sales against an inventory based on average costs.

These favorable variances were partially offset by the unfavorable impact of the following:

- *Mark-to-Market Gain and Inventory Valuation Adjustment* Revenues for the nine months of 2008 include a net mark-to-market gain of approximately $72 million, a portion of which was offset by a lower of cost or market inventory valuation adjustment of approximately $65 million. The comparable 2009 period included a net mark-to-market loss of approximately $34 million. The gain in 2008 was primarily the result of the impact that the significant decrease in crude oil and LPG prices that occurred during the third quarter of 2008 had on financial derivatives we were utilizing in risk management strategies. The gains and losses are generally offset by future physical positions that are not included in the mark-to-market calculation because they qualify for the NPNS scope exception under FASB guidance. In addition, a portion of the risk management strategies were related to certain crude oil and LPG inventories which were revalued to market prices as of September 30, 2008 resulting in a loss in Purchases and related costs of approximately $65 million. There was no inventory valuation adjustment for the nine months of 2009. The mark-to-market loss in the nine months of 2009 is associated with underlying physical activity that will occur in subsequent periods.

- *Crude Oil and Refined Products Marketing* Lower results from our gathering and marketing activities in the third quarter of 2009 as compared to the third quarter of 2008. The 2009 period was negatively impacted by tighter differentials and lower volumes of lease gathering crude oil purchases and waterborne foreign crude oil import barrels.

Equity Compensation Charges. Equity compensation charges increased in 2009 compared to 2008 primarily as a result of an increase in unit price for the nine-month period ended September 30, 2009 compared to a decrease in unit price for the nine-month period ended September 30, 2008. See Note 9 to our Condensed Consolidated Financial Statements for additional information on our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased approximately $10 million and $23 million for the three and nine months ended September 30, 2009 compared to the three and nine months ended September 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 a $3 million impairment of excess equipment in the first quarter of 2009 and a $3 million gain on sale of non-core assets in the third quarter of 2008.

Interest Expense. Interest expense for the three and nine months ended September 30, 2009 increased approximately $7 million and $22 million in comparison to the three and nine months ended September 30, 2008, respectively. Although the overall average debt balance in the comparable three month periods stayed relatively constant, there was an increase in interest expense primarily related to higher average rates as more of the balance was shifted to the senior notes. The nine month period of 2009 had a higher average debt balance than the comparable 2008 period which led to much of the increase as well as less capitalized interest and interest allocated to contango transactions which is recorded in purchases and related costs.

Other Income/(Expense), Net. Other income/(expense), net decreased by approximately $2 million and $10 million for the three and nine months ended September 30, 2009 in comparison to the same periods during 2008, respectively. The decrease in other income/(expense), net was primarily a result of the significant gains recognized during the prior year. The gains during the prior year included (i) a gain of approximately $12 million resulting from the sale of our shares in NYMEX Holdings, Inc., which was recognized during the third quarter of 2008 and (ii) a gain of approximately $11 million on the forward currency exchange hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition, which was recognized during the second quarter of 2008. During the current year, we recognized a (i) net gain of approximately $9 million in connection with our PNGS Acquisition, which occurred during the third quarter of 2009 and (ii) approximately $5 million of foreign currency gains, which were recognized throughout 2009. See Note 4 to the Condensed Consolidated Financial Statements for further discussion regarding our PNGS Acquisition.

Income Tax Expense. Income tax expense decreased approximately $1 million and $6 million for the three and nine months ended September 30, 2009 compared to the three and nine months ended September 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 11 to our Condensed Consolidated Financial Statements regarding the tax treatment of certain of our Canadian subsidiaries.

Liquidity and Capital Resources

General

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At September 30, 2009, we had a working capital surplus of approximately $157 million and approximately of $1.6 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

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		As of September 30, 2009
Availability under our senior unsecured revolving credit facility	$	1,198
Availability under our senior secured hedged inventory facility		425
Cash and cash equivalents		16
Total (1)	$	1,639

(1) On October 5, 2009, we utilized approximately $260 million of our available liquidity to redeem all of our outstanding $250 million 7.13% senior notes due in 2014.

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/or 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 risks that may impact our liquidity and capital resources. We are currently in compliance with the covenants contained in our credit agreements and indentures.

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 nine 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 net increased levels of inventory were financed through borrowings under our credit facilities and senior note issuances resulting in a negative impact to our operating cash flow for the period.

Our cash flow provided by operating activities in the first nine months of 2008 was approximately $239 million, resulting from cash generated by our recurring operations and our primary drivers. Also, during 2008 we increased our inventory levels primarily related to the routine seasonal build of LPG inventory which occurred in the third quarter. This increase in inventory was financed under our credit facilities and had a negative impact on our cash flow from operations for the first nine months of 2008.

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.

Registration Statements. We periodically access the capital markets for debt and equity financing. In November 2008, we filed a registration statement with the Securities and Exchange Commission (SEC) covering the issuance of up to $2 billion in debt or equity securities. As of September 30, 2009, approximately $191 million of unsold securities remained available under this registration statement. In order to replenish this availability, in October 2009 we filed the following registration statements with the SEC:

- A shelf registration statement, which, when declared effective by the SEC, will provide us with the ability to offer and sell up to $2.0 billion of debt and equity securities, subject to market conditions and our capital needs.

- A universal shelf registration statement, which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. This registration statement was immediately effective upon filing.

Senior Notes. In September 2009, we completed the issuance of $500 million of 5.75% senior notes due January 15, 2020. The senior notes were sold at 99.523% of face value. Interest payments are due on January 15 and July 15 of each year, beginning on January 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS Acquisition (which included repayment of all of PNGS s debt). See Note 4 to our Condensed Consolidated Financial Statements for further discussion of the PNGS Acquisition.

On August 15, 2009, our $175 million senior notes matured. We utilized 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. These 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.

Equity Offerings. In September 2009, we completed the issuance of 5,290,000 common units at $46.70 per unit for net proceeds of approximately $246 million. The net proceeds include our general partner s proportionate capital contribution and is reflected net of costs associated with the offering.

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 nine months ended September 30, 2009, we had net repayments on our revolving credit facility and our hedged inventory facility of approximately $454 million and $180 million, respectively. The net repayments resulted primarily from proceeds from our other financing activities discussed above. During the nine months ended September 30, 2008, we had net borrowings on our revolving credit facility and hedged inventory facility of approximately $259 million and $111 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 8 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, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. The incentive distribution reduction in connection with the PNGS Acquisition will become effective upon payment of a quarterly distribution of $0.9200 per limited partner unit. See Note 8 to our Condensed Consolidated Financial Statements for details related to the general partner s incentive distribution reduction.

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

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Contingencies

See Note 12 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. The amounts presented in the table below include our best estimate as of September 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)	$ 317	$ 261	$ 261	$ 950	$ 472	$ 5,141	$ 7,402
Leases (2)	$ 29	$ 72	$ 61	$ 54	$ 33	$ 258	$ 507
Crude oil, refined products and LPG purchases (3)	$ 3,216	$ 1,246	$ 495	$ 305	$ 6	$	$ 5,268

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at September 30, 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 September 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 obligations for the purchase of crude oil. At September 30, 2009 and December 31, 2008, we had outstanding letters of credit of approximately $66 million and $51 million, respectively.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

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

Forward-Looking Statements and Associated Risks

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

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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, grade differentials and volatility (or lack thereof);

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

- the effects of competition;

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

- increased costs or lack of availability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;

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

- future developments and circumstances at the time distributions are declared;

- general economic, market or business conditions and the amplification of other risks caused by 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.

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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 10 to our Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

All of our open commodity price risk derivatives at September 30, 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	$ 67	$ 14
Swaps and options contracts	43	44
LPG and other:		
Futures contracts	(5)	
Swaps, options and other contracts (1)	(51)	(17)
Total Fair Value	$ 54	

(1) Amount includes an asset of approximately $8 million associated with LPG physical contracts not eligible for the NPNS scope exception under FASB guidance.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

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

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Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

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

Item 1A. RISK FACTORS

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

Repurchases of Equity Securities

Period	**Total Number of Units Purchased**	**Average Price Paid per Unit**	**Total Number of Units Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number (or approximate dollar value) of Units that May Yet be Purchased Under the Plans or Programs**
July 1, 2009 - July 31, 2009		N/A	N/A	N/A
August 1, 2009 - August 31, 2009	9,063(1)	$ 47.56	N/A	N/A
September 1, 2009 - September 30, 2009		N/A	N/A	N/A
Total	$ 9,063			

(1) In August 2009, we purchased 9,063 common units from our general partner for an average price of $47.56 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our Long-Term Incentive Plans.

Issuances of Equity Securities

In connection with the acquisition of a 50% interest in PNGS, the Partnership issued 1,907,305 of its common units as a portion of the consideration paid for such interest. The Partnership believes that this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act of 1933, as amended, or Regulation D promulgated thereunder. The seller represented its intention to acquire the common units for investment only and not with a view toward their distribution.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	Amendment No. 6 dated September 3, 2009 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 September 3, 2009).
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 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	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).
3.10	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009.
3.11	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).
3.12	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).
3.13	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).
3.14	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).

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4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.10	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.12	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.13	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.14	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.15	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.16	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.17	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated

by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).

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4.18	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.19	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 71/8% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.20	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed March 9, 2005).
4.21	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.22	Third Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).
4.23	Fourth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.24	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2008).
4.25	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.26	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.27	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.28	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).

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31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101	The following financial information from the quarterly report on Form 10-Q of Plains All American Pipeline, L.P. for the quarter ended September 30, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

Filed herewith

** Management compensatory plan or arrangement

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SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Date: November 6, 2009

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

Date: November 6, 2009

By: /s/ AL SWANSON
Al Swanson, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

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EXHIBIT INDEX

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	Amendment No. 6 dated September 3, 2009 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 September 3, 2009).
3.8	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).
3.9	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).
3.10	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009.
3.11	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).
3.12	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).
3.13	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).
3.14	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	

First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

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

4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.10	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.12	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.13	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.14	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.15	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.16	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.17	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee

(incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).

4.18	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.19	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 71/8% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.20	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed March 9, 2005).
4.21	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.22	Third Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).
4.23	Fourth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.24	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2008).
4.25	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.26	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.27	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.28	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).

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31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101	The following financial information from the quarterly report on Form 10-Q of Plains All American Pipeline, L.P. for the quarter ended September 30, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

Filed herewith

** Management compensatory plan or arrangement