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

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2008

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

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

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

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

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

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

(in millions, except units)

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

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

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

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

(in millions, except per unit data)

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

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

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

(in millions)

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

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

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

(in millions)

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(unaudited)		(unaudited)	
Net income	$ 41	$ 105	$ 133	$ 190
Other comprehensive income/(loss)	20	58	(45)	45
Comprehensive income	$ 61	$ 163	$ 88	$ 235

CONDENSED CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total

			(unaudited)			
Balance at December 31, 2007	$	4	$	176	$	180
Reclassification adjustments for settled contracts		8				8
Changes in fair value of outstanding hedge positions		(15)				(15)
Currency translation adjustment				(38)		(38)
Total period activity		(7)		(38)		(45)
Balance at June 30, 2008	$	(3)	$	138	$	135

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

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

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2007 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated. The results of operations for the three months and six months ended June 30, 2008 should not be taken as indicative of the results to be expected for the full year.

Note 2 Recent Accounting Pronouncements

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

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

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

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

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

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

Note 3 Trade Accounts Receivable

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

Recent turmoil in the financial markets, which escalated late in the first quarter of 2008, resulted in unprecedented actions by the Federal Reserve Bank to provide liquidity to financial institutions. In addition, in the second quarter of 2008, as the values of crude oil and refined products are at historically high levels, there have been liquidity issues at some companies with which we do business. We believe these conditions, combined with significant energy price volatility, have increased the potential credit risks associated with certain financial institutions and trading companies with which we do business. However, we have a rigorous credit review process and closely monitor these conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or parental guarantees.

At June 30, 2008 and December 31, 2007, we had received approximately $152 million and $43 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with most of our counterparties. These arrangements cover a significant portion of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At June 30, 2008 and December 31, 2007, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts may vary significantly from estimated amounts.

Note 4 Acquisitions and Investment in Unconsolidated Entities

Acquisitions

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

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

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

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

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

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

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

Investment in Unconsolidated Entities

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

Note 5 Inventory and Linefill

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

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

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

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

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

Note 6 Debt

Debt consisted of the following (in millions):

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

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

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

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

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

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

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

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

Letters of Credit

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

Note 7 Earnings per Limited Partner Unit

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

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

(1) Our LTIP awards (described in Note 9) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS No. 128, *Earnings per Share.*

Note 8 Partners Capital and Distributions

Equity Offerings

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

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

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

LTIP Vesting

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

Distributions

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

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

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

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

Note 9 Equity Compensation Plans

Long-Term Incentive Plans

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

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

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

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

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

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

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

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

	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2007	3.6	$ 37.73
Granted	0.4	$ 33.80
Vested	(0.1)	$ 37.60
Cancelled or forfeited	(0.1)	$ 48.78
Outstanding at June 30, 2008	3.8	$ 37.46

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

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approximately $51 million.

Class B Units of Plains AAP, L.P.

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

Other Consolidated Information

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

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

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

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

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

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

Note 10 Derivative Instruments and Hedging Activities

The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, the ICE and over-the-counter, including commodity swap and option contracts entered into with financial institutions and other energy companies.

Summary of Financial Impact

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

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

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

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

The breakdown of the net mark-to-market impact to earnings between derivatives that do not qualify for hedge accounting and the ineffective portion of cash flow hedges is as follows (in millions, losses designated in parentheses):

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

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

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

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

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

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

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

In addition to the $3 million of unrealized gain as of June 30, 2008 and the $9 million of unrealized gain as of December 31, 2007 deferred to AOCI for open derivative positions, AOCI also includes deferred losses of approximately $6 million and $5 million as of June 30, 2008 and December 31, 2007, respectively, that relate to terminated interest rate hedging instruments that were settled in connection with the issuance and refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the underlying debt.

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

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

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

Adoption of SFAS 157

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

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

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Recurring Fair Value Measures

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

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

Level 1

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

Level 2

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

Level 3

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

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

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

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

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

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Rollforward of Level 3 Net Liability

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

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

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

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

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

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

Note 11 Income Taxes

U.S. Federal and State Taxes

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

Canadian Federal and Provincial Taxes

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

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Note 12 Commitments and Contingencies

Litigation

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4 million to $5 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. The EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the DOJ) for further investigation in connection with a civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with the DOJ and the EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that the EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by the EPA, and will continue to engage in discussions with the EPA and the DOJ with respect to such mitigating circumstances and factors, as well as the injunctive remedies proposed.

On November 15, 2006, we completed the Pacific merger. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, in March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four-count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine, if any, that can be assessed is estimated to be approximately $1.4 million, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered and the State of California has the discretion to further reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the alleged offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are in settlement discussions with the State of California.

The EPA is also pursuing a claim in connection with this release and has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $4.2 million. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and

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

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

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

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

Environmental

We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain a program designed to help prevent releases, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. The inclusion of additional miles of pipe in our operations may, however, result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link Energy LLC in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas.

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

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

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we

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consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material, favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

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

Note 13 Operating Segments

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

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

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

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

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

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

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

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

Note 14 Supplemental Condensed Consolidating Financial Information

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

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting (all amounts in millions):

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Condensed Consolidating Balance Sheet
As of June 30, 2008

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

As of December 31, 2007

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

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

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

Three Months Ended June 30, 2007

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

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

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

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

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

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	Condensed Consolidating Statements of Cash Flows Six Months Ended June 30, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 133	$ 219	$ 22	$ (241)	$ 133
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	1	89	10		100
SFAS 133 mark-to-market adjustment		92			92
Equity compensation expense		24			24
Gain on foreign currency revaluation		(10)			(10)
Equity earnings in unconsolidated entities, net of distributions	(214)	(23)		242	5
Deferred income tax expense		(3)			(3)
Other		(5)			(5)
Changes in assets and liabilities, net of acquisitions	(541)	800	(18)	(1)	240
Net cash provided by operating activities	(621)	1,183	14		576
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions		(661)			(661)
Additions to property and equipment		(287)	(14)		(301)
Investment in unconsolidated entities	(40)				(40)
Proceeds from sales of assets		15			15
Net cash used in investing activities	(40)	(933)	(14)		(987)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		(204)			(204)
Net repayments on short-term letter of credit and hedged inventory facility		(56)			(56)
Proceeds from the issuance of senior notes	597				597
Net proceeds from the issuance of common units	315				315
Distributions paid to common unitholders and general partner	(251)				(251)
Other financing activities	(5)				(5)
Net cash provided by (used in) financing activities	656	(260)			396
Effect of translation adjustment on cash		2			2
Net decrease in cash and cash equivalents	(5)	(8)			(13)
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ (4)	$ 15	$	$	$ 11

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

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Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2007 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Condensed Consolidated Financial Statements.

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

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

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

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

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

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

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

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

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

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

Acquisitions and Internal Growth Projects

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

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

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

Acquisitions

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

Internal Growth Projects

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

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

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

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

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

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

Results of Operations

Analysis of Operating Segments

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

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Transportation

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

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