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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, 2010

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
333 Clay Street, Suite 1600, Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 646-4100

(Registrant s telephone number, including area code)

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

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). x Yes ¨ No

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 ¨ Non-accelerated filer ¨ (Do not check if a smaller reporting company) Smaller reporting company ¨

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

As of August 2, 2010, there were 136,419,175 Common Units outstanding. The common units trade on the New York Stock Exchange under the ticker symbol PAA.

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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, 2010 (unaudited)	December 31, 2009 (unaudited)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15	$ 25
Trade accounts receivable and other receivables, net	1,937	2,253
Inventory	1,483	1,157
Other current assets	63	223
Total current assets	3,498	3,658
PROPERTY AND EQUIPMENT	7,417	7,240
Accumulated depreciation	(1,007)	(900)
	6,410	6,340
OTHER ASSETS		
Linefill and base gas	504	501
Long-term inventory	118	121
Goodwill	1,285	1,287
Other, net	553	451
Total assets	$ 12,368	$ 12,358
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,181	$ 2,295
Short-term debt	1,025	1,074
Other current liabilities	171	413
Total current liabilities	3,377	3,782
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $13 and $14, respectively	4,137	4,136
Long-term debt under credit facilities and other	213	6
Other long-term liabilities and deferred credits	226	275

Total long-term liabilities	4,576	4,417
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS CAPITAL		
Common unitholders (136,419,175 and 136,135,988 units outstanding, respectively)	4,086	4,002
General partner	98	94
Total partners capital excluding noncontrolling interests	4,184	4,096
Noncontrolling interests	231	63
Total partners capital	4,415	4,159
Total liabilities and partners capital	$ 12,368	$ 12,358

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)		(unaudited)	
REVENUES				
Supply & Logistics segment revenues	$ 5,901	$ 4,099	$ 11,813	$ 7,231
Transportation segment revenues	139	130	277	254
Facilities segment revenues	84	53	158	100
Total revenues	6,124	4,282	12,248	7,585
COSTS AND EXPENSES				
Purchases and related costs	5,641	3,829	11,263	6,619
Field operating costs	171	160	334	312
General and administrative expenses	56	54	117	100
Depreciation and amortization	64	56	131	114
Total costs and expenses	5,932	4,099	11,845	7,145
OPERATING INCOME	192	183	403	440
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	1	5	2	8
Interest expense (net of capitalized interest of $3, $2, $9 and $5, respectively)	(62)	(56)	(120)	(107)
Other income, net	2	2	(1)	5
INCOME BEFORE TAX	133	134	284	346
Current income tax (expense)/benefit	1		(1)	(2)
Deferred income tax (expense)/benefit	(1)	2	1	3
NET INCOME	133	136	284	347
Less: Net income attributable to noncontrolling interests	(2)		(2)	
NET INCOME ATTRIBUTABLE TO PLAINS	$ 131	$ 136	$ 282	$ 347
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 90	$ 102	$ 201	$ 282
GENERAL PARTNER	$ 41	$ 34	$ 81	$ 65
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 0.79	$ 1.45	$ 2.20

DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 0.78	$ 1.45	$ 2.18
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	136	129	136	126
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	137	130	137	127

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six Months Ended June 30, 2010	2009
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 284	$ 347
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	131	114
Equity compensation charge	33	30
Gain on sale of linefill	(17)	
Inventory valuation adjustments	3	
Other	5	(1)
Changes in assets and liabilities, net of acquisitions	(156)	(203)
Net cash provided by operating activities	283	287
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(184)	(56)
Additions to property, equipment and other	(215)	(228)
Cash received for sale of noncontrolling interest in a subsidiary	268	26
Net cash received for linefill	18	7
Investment in unconsolidated entities		(5)
Other investing activities	3	3
Net cash used in investing activities	(110)	(253)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on Plains revolving credit facility	(150)	(459)
Net borrowings on PNG revolving credit facility	205	
Net borrowings on short-term letter of credit and hedged inventory facility	100	157
Net proceeds from the issuance of senior notes		350
Net proceeds from the issuance of common units		210
Distributions paid to common unitholders (Note 7)	(253)	(227)
Distributions paid to general partner (Note 7)	(82)	(64)
Other financing activities	(2)	(5)
Net cash used in financing activities	(182)	(38)
Effect of translation adjustment on cash	(1)	
Net decrease in cash and cash equivalents	(10)	(4)
Cash and cash equivalents, beginning of period	25	11
Cash and cash equivalents, end of period	$ 15	$ 7

Cash paid for interest, net of amounts capitalized	$	123	$	103
Cash paid/(refunded) for income taxes, net	$	20	$	7

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners Capital
			(unaudited)			
Balance, December 31, 2009	136	$ 4,002	$ 94	$ 4,096	$ 63	$ 4,159
Net income		201	81	282	2	284
Sale of noncontrolling interest in a subsidiary (Note 7)		99	2	101	167	268
Distributions to limited partners and general partner (Note 7)		(253)	(82)	(335)		(335)
Issuance of common units under LTIP		16		16		16
Other comprehensive income		19		19		19
Other		2	3	5	(1)	4
Balance, June 30, 2010	136	$ 4,086	$ 98	$ 4,184	$ 231	$ 4,415

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)		(unaudited)	
Net income	$ 133	$ 136	$ 284	$ 347
Other comprehensive income/(loss)	(45)	(32)	19	(152)
Comprehensive income	88	104	303	195
Less: Comprehensive income attributable to noncontrolling interests	(2)		(2)	
Comprehensive income attributable to Plains	$ 86	$ 104	$ 301	$ 195

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2009	$ 18	$ 106	$ (1)	$ 123

Reclassification adjustments		29						29
Net deferred gains on cash flow hedges		14						14
Currency translation adjustment				(24)				(24)
Total period activity		43		(24)				19
Balance, June 30, 2010	$	61	$	82	$	(1)	$	142

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

Organization

We engage in the transportation, storage, terminalling and marketing of crude oil, refined products and LPG. We also engage in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 11 for further detail of our operating segments.

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.

Definitions

The following additional defined terms are used in this Form 10-Q and shall have the meanings indicated below:

AOCI	= Accumulated other comprehensive income
API 653	= American Petroleum Institute Standard 653
Bcf	= Billion cubic feet
CAA	= Clean Air Act
CAD	= Canadian Dollar
Class B units	= Class B units of Plains AAP, L.P.
DCP	= Disclosure controls and procedures
DERs	= Distribution Equivalent Rights
DOJ	= United States Department of Justice
EPA	= United States Environmental Protection Agency
FERC	= Federal Energy Regulation Commission
FASB	= Financial Accounting Standards Board
ICE	= IntercontinentalExchange
IPO	= Initial Public Offering
LIBOR	= London Interbank Offered Rate
LPG	= Liquefied petroleum gas and other natural gas-related petroleum products
LTIP	= Long term incentive plan
Mcf	= Thousand cubic feet
MLP	= Master limited partnership
MTBE	= Methyl tertiary-butyl ether
NJDEP	= New Jersey Department of Environmental Protection
NYMEX	= New York Mercantile Exchange
NPNS	= Normal purchase and normal sale
PNG	= PAA Natural Gas Storage, L.P.
PNGS	= PAA Natural Gas Storage, LLC
PAT	= Pacific Atlantic Terminals, LLC
Rainbow	= Rainbow Pipe Line Company Ltd.
RMPS	= Rocky Mountain Pipeline System
SEC	= Securities and Exchange Commission

U.S. GAAP	= United States generally accepted accounting principles
USD	= United States Dollar
WTI	= West Texas Intermediate

Basis of Consolidation and Presentation

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2009 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the SEC. All adjustments (consisting only of

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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 in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to Plains. The condensed balance sheet data as of December 31, 2009 was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP. The results of operations for the three and six months ended June 30, 2010 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 and have been included within the following footnotes where applicable.

Note 2 Recent Accounting Pronouncements

Fair Value Measurement Disclosure Requirements. In January 2010, the FASB issued guidance relating to fair value measurements. This new guidance requires additional disclosures regarding transfers in and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. This guidance is effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance, which is effective for the first interim or annual reporting period beginning after December 15, 2009, on January 1, 2010. Our adoption did not have any material impact on our financial position, results of operations, or cash flows. See Note 9 for applicable disclosure. We will adopt the guidance that will be effective for annual reporting periods beginning after December 15, 2010 on January 1, 2011. We do not expect that adoption of this guidance will have any material impact on our financial position, results of operations, or cash flows.

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. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At June 30, 2010 and December 31, 2009, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $4 million and $9 million at June 30, 2010 and December 31, 2009, respectively. The decrease in our allowance for doubtful accounts receivable balance during the six months ended June 30, 2010 primarily is due to the collection and related settlement of claims for receivables that had been reserved for during the years ended December 31, 2009 and 2008. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

At June 30, 2010 and December 31, 2009, we had received approximately $201 million and $212 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables between the two) that cover a significant part of our transactions and also serve to mitigate credit risk.

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Note 4 Inventory, Linefill, Base Gas and Long-term Inventory

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

	June 30, 2010				December 31, 2009			
	Volumes	Unit of Measure	Total Value	Price/ Unit [1]	Volumes	Unit of Measure	Total Value	Price/ Unit [1]
Inventory								
Crude oil	16,233	barrels	$ 1,179	$ 72.63	12,232	barrels	$ 886	$ 72.43
LPG	6,195	barrels	301	$ 48.59	6,051	barrels	247	$ 40.82
Refined products	37	barrels	2	$ 54.05	283	barrels	21	$ 74.20
Natural gas [2]	110	mcf		$ 3.36	181	mcf	1	$ 3.30
Parts and supplies	N/A		1	N/A	N/A		2	N/A
Inventory subtotal			1,483				1,157	
Linefill and base gas								
Crude oil	9,162	barrels	462	$ 50.43	9,404	barrels	471	$ 50.09
Natural gas [2]	11,194	mcf	38	$ 3.39	9,194	mcf	28	$ 3.04
LPG	79	barrels	4	$ 50.63	52	barrels	2	$ 38.46
Linefill and base gas subtotal			504				501	
Long-term inventory								
Crude oil	1,425	barrels	97	$ 68.07	1,497	barrels	103	$ 68.80
LPG	487	barrels	21	$ 43.12	458	barrels	18	$ 39.30
Long-term inventory subtotal			118				121	
Total			$ 2,105				$ 1,779	

(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) The volumetric ratio of mcf of natural gas to barrels of crude oil is 6:1; thus, natural gas volumes can be converted to barrels by dividing by 6.

The inventory balances at June 30, 2010 include an inventory valuation adjustment, which resulted in a loss of approximately $3 million, related to certain crude oil inventories that were revalued to market prices at June 30, 2010.

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Note 5 Debt

Debt consists of the following (in millions):

	June 30, 2010	December 31, 2009
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.6% and 2.5% as of June 30, 2010 and December 31, 2009, respectively	$ 400	$ 300
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% for both periods presented [1]	623	772
Other	2	2
Total short-term debt	1,025	1,074
Long-term debt:		
Senior notes, net of unamortized discounts [2]	4,137	4,136
Long-term debt under credit facilities and other [3]	213	6
Total long-term debt [1] [4]	4,350	4,142
Total debt	$ 5,375	$ 5,216

(1) We classify 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 NYMEX and ICE margin deposits.

(2) A portion of this balance consists of our $500 million of 4.25% senior notes due September 2012 that were issued in July 2009 and the proceeds from which are being used to supplement capital available from our hedged inventory facility. At June 30, 2010 and December 31, 2009, approximately $500 million and $222 million, respectively, had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(3) In April 2010, our consolidated subsidiary PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin (as defined by the credit agreement), may be expanded to $600 million, subject to additional lender commitments and with approval of the administrative agent for the credit facility. At June 30, 2010, borrowings of approximately $205 million were outstanding under this facility. See the *Sale of Noncontrolling Interest in a Subsidiary* section of Note 7 for additional discussion regarding PNG.

(4) Our fixed-rate senior notes have a face value of approximately $4.2 billion as of June 30, 2010. We estimate the aggregate fair value of these notes as of June 30, 2010 to be approximately $4.4 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.

Senior Notes

In July 2010, we completed the issuance of $400 million of 3.95% Senior Notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, beginning on September 15, 2010. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities, which may be reborrowed to fund our ongoing expansion capital program, potential future acquisitions or the potential redemption of our outstanding 6.25% senior notes that mature in September 2015.

Letters of Credit

In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At June 30, 2010 and December 31, 2009, we had outstanding letters of credit of approximately $103 million and $76 million, respectively.

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Note 6 Net Income 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, 2010 and 2009 (amounts in millions, except per unit data):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Numerator for basic and diluted earnings per limited partner unit:				
Net income attributable to Plains	$ 131	$ 136	$ 282	$ 347
Less: General partner s incentive distribution paid[1]	(39)	(32)	(77)	(60)
Subtotal	92	104	205	287
Less: General partner 2% ownership [1]	(2)	(2)	(4)	(5)
Net income available to limited partners	90	102	201	282
Adjustment in accordance with application of the two-class method for MLPs [1]	(1)		(3)	(5)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 89	$ 102	$ 198	$ 277
Denominator:				
Basic weighted average number of limited partner units outstanding	136	129	136	126
Effect of dilutive securities:				
Weighted average LTIP units [2]	1	1	1	1
Diluted weighted average number of limited partner units outstanding	137	130	137	127
Basic net income per limited partner unit	$ 0.65	$ 0.79	$ 1.45	$ 2.20
Diluted net income per limited partner unit	$ 0.65	$ 0.78	$ 1.45	$ 2.18

(1) We calculate net income available to limited partners based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance 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. After adjusting for this distribution, 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 for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLPs.

(2) Our LTIP awards (described in Note 8) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

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Note 7 Partners Capital and Distributions

Sale of Noncontrolling Interest in a Subsidiary

On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests at $21.50 per common unit. The number of units issued at closing included 1,758,000 common units issued pursuant to the full exercise of the underwriters over-allotment option. Net proceeds received by PNG from the sale of the 13,478,000 common units were approximately $268 million and were used to repay amounts outstanding under our credit facilities and for general partnership purposes. The common units offered represent approximately 23% of the outstanding equity of PNG. We own the remaining 77% equity interest in PNG and control the entity, and therefore, continue to consolidate the financial results.

Prior to the PNG IPO, we owned 100% of PNGS natural gas storage business, the predecessor of PNG, and related operating entities. Immediately prior to the closing of the IPO, we contributed 100% of the equity interests in PNGS and its subsidiaries to PNG in exchange for approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2% general partner interest and incentive distribution rights. In conjunction with the offering, we recorded non-controlling interest of $167 million associated with the book value of PNG sold to the public. We also recorded an increase to our partners capital of approximately $101 million associated with the net increase from our share of the proceeds received in the offering partially offset by the dilution of our interest in PNG resulting from the IPO.

The Series A subordinated units are not entitled to receive any distributions until the common units have received the minimum quarterly distribution ($1.35 on an annualized basis) plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The Series A subordinated units will convert to common units once certain earnings and distribution targets are met for three consecutive, non-overlapping four quarter periods. The Series B subordinated units are not entitled to participate in quarterly distributions until they convert into Series A subordinated units. The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

- 4,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) PNG makes a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights;

- 3,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) PNG makes a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

- 3,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) PNG makes a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights.

PNG s general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described

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above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

The following table reflects the changes in the noncontrolling interests in partners capital (in millions):

	For the Six Months Ended June 30, 2010	2009
Beginning balance	$ 63	$
Sale of noncontrolling interests in subsidiaries	167	64
Net income attributable to noncontrolling interests	2	2
Other	(1)	(3)
Ending Balance	$ 231	$ 63

PAA Equity Offerings

We did not complete any equity offerings during the six months ended June 30, 2010; however, we completed the following equity offering of our common units during the six months ended June 30, 2009 (in millions, except unit and per unit data):

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

(1) This offering of common units was an underwritten transaction that required us to pay a gross spread. The net proceeds from this offering were used to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

PAA Distributions

The following table details the distributions pertaining to the first six months of 2010 and 2009, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid	Distributions Paid Common Units	General Partner Incentive	General Partner 2%	Total	Distributions per limited partner unit
2010						
July 13, 2010	August 13, 2010 (1)	$ 129	$ 40	$ 3	$ 172	$ 0.9425
April 13, 2010	May 14, 2010	$ 127	$ 39	$ 3	$ 169	$ 0.9350
January 20, 2010	February 12, 2010	$ 126	$ 37	$ 3	$ 166	$ 0.9275
2009						
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

(1) Payable to unitholders of record on August 3, 2010, for the period April 1, 2010 through June 30, 2010.

Upon closing of the Pacific acquisition in November 2006, the Rainbow acquisition in May 2008 and the PNGS acquisition in September 2009, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to these acquisitions is $83 million. Following the distribution in August 2010, the aggregate incentive distribution reductions remaining will be approximately $11 million. See Note 2 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further detail regarding our *General Partner Incentive Distributions*.

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Note 8 Equity Compensation Plans

For discussion of our LTIP awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K.

On April 27, 2010, PNG s general partner adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the PNG 2010 LTIP Plan). The PNG 2010 LTIP Plan consists of restricted units, phantom units, unit options, unit appreciation rights and unit awards. The PNG 2010 LTIP Plan limits the number of PNG common units that may be delivered pursuant to awards under the plan to 3,000,000. In May 2010, PNG s board of directors approved the grant of 658,500 phantom units (representing approximately 1% of the currently outstanding PNG limited partner units) under the PNG 2010 LTIP Plan to directors, officers and other employees of PNG, a portion of which were granted upon conversion of outstanding awards denominated in common units of PAA.

At June 30, 2010, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

LTIP Units Outstanding	PAA Distribution Required	2010	2011	2012	2013	2014	2015
2.8(1)	$3.50 - $4.45		0.5	0.8	0.5	0.5	0.5
1.7(2)	$3.50 - $4.25	0.5	0.2	0.7	0.2	0.1	
4.5(3)(4)		0.5	0.7	1.5	0.7	0.6	0.5

(1) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.45 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) 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, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 3 million of our approximately 4.5 million outstanding LTIP awards also include DERs, of which approximately 1 million are currently earned.

(4) LTIP units outstanding do not include Class B units described below.

Additionally, at June 30, 2010, the following LTIP awards, denominated in PNG units, were outstanding (units in millions):

LTIP Units Outstanding	PNG Distribution Required	2010	2011	2012	2013	2014	2015
0.4(1)	$1.55 - $1.90			0.1		0.1	0.2
0.3(2)	Other		0.1	0.1	0.1		
0.7(3)			0.1	0.2	0.1	0.1	0.2

(1) These LTIP awards have performance conditions requiring the attainment of an annualized PNG distribution of between $1.55 and $1.90 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) These LTIP awards have performance conditions requiring the conversion of PNG s Series A and Series B subordinated units (see Note 7). For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 0.3 million of these LTIP awards also include DERs, of which none are currently earned.

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Our LTIP activity for awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units		PNG Units	
	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2009	3.9	$ 36.40		$
Granted	1.5	$ 42.39	0.7	$ 19.72
Vested	(0.6)	$ 34.67		$
Cancelled or forfeited	(0.3)	$ 33.53		$
Outstanding, June 30, 2010 (1) (2)	4.5	$ 38.93	0.7	$ 19.72

(1) PAA includes approximately 1 million equity classified awards.
(2) The majority of the PNG awards are equity classified.

Our accrued liability at June 30, 2010 related to all outstanding liability classified LTIP awards and DERs is approximately $78 million. This liability includes accruals associated with our assessment that an annualized PAA distribution of $3.90 is probable. This liability also includes accruals associated with our assessment that an annualized PNG distribution of $1.45 and the conversion of PNG s Series A subordinated units and the first tranche of PNG s Series B subordinated units are probable of occurring. At December 31, 2009, the accrued liability was approximately $87 million.

Class B Units of PAA s General Partner

For further discussion of the Class B units, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K. The following table contains a summary of Class B unit awards that were (i) reserved for future grants (ii) outstanding and (iii) earned as of and for the six months ended June 30, 2010 and as of December 31, 2009:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding Class B Units (1) (in millions)
Balance, December 31, 2009	34,500	165,500	38,500	$ 36
Class B unit issuance				
Class B units earned				
Class B units forfeited	1,500	(1,500)	(375)	
Balance, June 30, 2010	36,000	164,000	38,125	$ 36

(1) Of the grant date fair value, approximately $2 million was recognized as expense during the six months ended June 30, 2010.

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Class B Units of PNG s General Partner

In July 2010, the Board of Directors of PNG s general partner authorized the issuance of 165,000 Class B Units (PNG Class B Units) of PNGS GP LLC (PNG s general partner). Approximately 97,625 PNG Class B Units were awarded and the remaining units are reserved for future grants. The PNG Class B Units are earned in 25% increments 180 days following annualized PNG distribution levels of $2.00, $2.30, $2.50 and $2.70. When earned, the PNG Class B Units participate in quarterly distributions paid to PNGS GP LLC to the extent such distributions exceed $2.5 million per quarter. Assuming all 165,000 PNG Class B Units were granted and earned, the maximum participation rate would be 6% of PNG s quarterly general partner distribution.

Other Consolidated Equity Compensation Information

We refer to our PAA LTIP plans, the PNG 2010 LTIP Plan and the Class B units of PAA s general partner collectively as Equity compensation plans. The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to our equity compensation plans (in millions):

	Three Months Ended June 30, 2010		Three Months Ended June 30, 2009	
	Liability Awards	**Equity Awards**	**Liability Awards**	**Equity Awards**
Equity compensation expense	$ 12	$ 2	$ 18	$ 1
LTIP unit vestings	$ 25	$	$ 18	$
LTIP cash settled vestings	$ 10	$	$ 7	$
DER cash payments	$ 1	$	$ 1	$

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2009	
	Liability Awards	**Equity Awards**	**Liability Awards**	**Equity Awards**
Equity compensation expense	$ 29	$ 4	$ 28	$ 2
LTIP unit vestings	$ 25	$	$ 18	$
LTIP cash settled vestings	$ 10	$	$ 7	$
DER cash payments	$ 2	$	$ 2	$

Based on the June 30, 2010 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $62 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value of our Equity compensation plans. For our liability classified awards, this estimate is based on the closing market price of our units of $58.70 at June 30, 2010. For our equity classified awards, this estimate is based on the closing price of the applicable units (PAA or PNG) as of the grant date. 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 Expense** (1) (2)
2010 (3)	$ 18
2011	24
2012	15
2013	4
2014	1
Total	$ 62

(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, 2010.

(2) Includes unamortized fair value associated with Class B units.

(3) Includes equity compensation plan fair value amortization for the remaining six months of 2010.

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Note 9 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use 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 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 (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 positions that are substantially balanced, 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, specifically authorized personnel can 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 supply and logistics operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of June 30, 2010, net derivative positions related to these activities included:

- An approximate 209,500 barrels per day net long position (total of 6.3 million barrels) associated with our crude oil activities, which was unwound ratably during July 2010 to match monthly average pricing.

- An approximate 23,800 barrels per day (total of 13.5 million barrels) net short spread position, which hedges a portion of our anticipated crude oil lease gathering purchases through January 2012. These derivatives protect our margin on future floating-price crude oil purchase commitments. These derivatives in the aggregate do not result in exposure to outright price movements.

- A net short spread position averaging approximately 1,000 barrels per day (total of 0.5 million barrels) of calendar spread call options for the period July 2010 through January 2012. These derivatives in the aggregate do not result in exposure to outright price movements.

An average of approximately 2,400 barrels per day (total of 0.6 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 March 2011.

Approximately 8,000 barrels per day on average (total of 4.3 million barrels) of WTS/WTI crude oil basis swaps through December 2011, which hedge anticipated sales of crude oil (WTI).

Storage Capacity Utilization We own approximately 62 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 supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk if the market structure is backwardated. As of June 30, 2010, we used derivatives to manage the risk of not utilizing approximately 2.4 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 supply and logistics activities. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of June 30, 2010, we had approximately 13.6 million barrels of inventory hedged with derivatives.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of June 30, 2010, we had approximately 1.9 million barrels of crude oil derivatives hedging the anticipated sale of foreign crude inventory.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of June 30, 2010, we had PLA hedges consisting of (i) a net short position consisting of crude oil futures and swaps for an average of approximately 2,200 barrels per day (total of 2.0 million barrels) through December 2012, (ii) a long put option position of approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 1.3 million barrels through December 2011.

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 June 30, 2010, we had an average of 1,200 barrels per day of natural gasoline/WTI spread positions (approximately 1 million barrels) that run through 2011.

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 such anticipated purchases of natural gas. As of June 30, 2010, we have a long position of approximately 1 Bcf consisting of natural gas futures contracts through August 2011 and natural gas call options for approximately 1 Bcf through August 2011.

The derivative instruments we use to manage our commodity price risk consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions. Over-the-counter transactions include commodity swap and option contracts. 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 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 to manage this risk consist primarily of interest rate swaps and treasury locks. As of June 30, 2010, AOCI includes deferred losses of $7 million 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. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the hedged debt instruments.

As of June 30, 2010, we had four outstanding interest rate swaps and three outstanding 10-year treasury locks. For the interest rate swaps, we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average 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. The 10-year treasury locks have an aggregate notional amount of $150 million and an average locked rate of 3.14%. All three 10-year treasury locks terminated in July 2010.

Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of June 30, 2010, AOCI includes net deferred gains of $17 million 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 June 30, 2010, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative, we enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At June 30, 2010, our open foreign exchange derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2010	$ 22	$ 19	CAD $ 1.14 to USD $1.00
2011	$ 15	$ 15	CAD $ 1.01 to USD $1.00
2012	$ 15	$ 15	CAD $ 1.01 to USD $1.00
2013	$ 9	$ 9	CAD $ 1.00 to USD $1.00

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

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Summary of Financial Impact

The majority of our derivative activity is related 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 impact earnings. 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 six months ended June 30, 2010 and 2009 is as follows (in millions):

Three months ended June 30, 2010 and 2009:

	Three Months Ended June 30, 2010				Three Months Ended June 30, 2009			
	Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge (3)		Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge (3)	
Location of gain/(loss)	**AOCI Reclass (1)**	**Ineffective Portion (2)**		**Total**	**AOCI Reclass (1)**	**Ineffective Portion (2)**		**Total**
Commodity Derivatives								
Supply and Logistics segment revenues	$ (7)	$ 1	$ 28	$ 22	$ 16	$ (7)	$ 35	$ 44
Transportation segment revenues					1			1
Purchases and related costs	(8)		11	3	1		20	21
Interest Rate Derivatives								
Interest expense			1	1				
Foreign Exchange Derivatives								
Supply and Logistics segment revenues			(3)	(3)			5	5
Purchases and related costs							2	2
Other income, net			1	1			(2)	(2)
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (15)**	**$ 1**	**$ 38**	**$ 24**	**$ 18**	**$ (7)**	**$ 60**	**$ 71**

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Six months ended June 30, 2010 and 2009:

	Six Months Ended June 30, 2010				Six Months Ended June 30, 2009			
	Derivatives in Cash Flow Hedging Relationships				Derivatives in Cash Flow Hedging Relationships			
Location of gain/(loss)	**AOCI Reclass (1)**	**Ineffective Portion (2)**	**Derivatives Not Designated as a Hedge (3)**	**Total**	**AOCI Reclass (1)**	**Ineffective Portion (2)**	**Derivatives Not Designated as a Hedge (3)**	**Total**
Commodity Derivatives								
Supply and Logistics segment revenues	$ (26)	$	$ 55	$ 29	$ 141	$ (8)	$ 6	$ 139
Transportation segment revenues	1			1	3			3
Facilities segment revenues	(1)		1					
Purchases and related costs	(3)		(13)	(16)	(31)		115	84
Interest Rate Derivatives								
Other income, net							(1)	(1)
Interest expense			2	2				
Foreign Exchange Derivatives								
Supply and Logistics segment revenues			(3)	(3)			5	5
Purchases and related costs			2	2			(3)	(3)
Other income, net					5		(2)	3
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (29)**	**$**	**$ 44**	**$ 15**	**$ 118**	**$ (8)**	**$ 120**	**$ 230**

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

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

(3) Includes realized and unrealized gains or losses for 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 on a gross basis as of June 30, 2010 (in millions):

As of June 30, 2010

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 210	Other current assets	$ (88)
	Other long-term assets	26	Other long-term assets	
	Other long-term liabilities	1	Other long-term liabilities	(1)
	Other current liabilities		Other current liabilities	(3)
Interest rate derivatives	Other current liabilities		Other current liabilities	(2)
Foreign exchange derivatives	Other long-term assets	2	Other long-term liabilities	
Total derivatives designated as hedging instruments		$ 239		$ (94)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 150	Other current assets	$ (114)
	Other long-term assets	27	Other long-term assets	(14)
	Other long-term liabilities	1	Other long-term liabilities	(2)
Interest rate derivatives	Other current assets	1	Other current assets	
	Other long-term assets	2	Other long-term assets	
	Other current liabilities	1	Other current liabilities	
Foreign exchange derivatives	Other current liabilities		Other current liabilities	(3)
Total derivatives not designated as hedging instruments		$ 182		$ (133)
Total derivatives		$ 421		$ (227)

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

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 153	Other current liabilities	$ (140)
	Other long-term assets	34	Other long-term liabilities	(1)
Foreign exchange derivatives	Other long-term assets	2	Other long-term liabilities	
Total derivatives designated as hedging instruments		$ 189		$ (141)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 34	Other current liabilities	$ (91)
	Other long-term assets	41	Other long-term liabilities	(34)

Interest rate derivatives	Other current assets		1	Other current liabilities		
	Other long-term assets		1	Other long-term liabilities		
Foreign exchange derivatives	Other current assets		2	Other current liabilities		(3)
Total derivatives not designated as hedging instruments		$	79		$	(128)
Total derivatives		$	268		$	(269)

As of June 30, 2010, there was a net gain of $61 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 earnings recognition of the underlying hedged physical transaction, (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 balances. Of the total net gain deferred in AOCI at June 30, 2010, we expect to reclassify a net gain of approximately $27 million to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 98% is expected to be reclassified to earnings prior to 2013 with the remaining deferred gain being reclassified to earnings through 2019. These amounts are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

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During the six months ended June 30, 2009, we discontinued a cash flow hedge as a result of the hedged transaction becoming no longer probable of occurring and reclassified a deferred gain of approximately $6 million from AOCI to other income. During the three months ended June 30, 2010 and 2009 and the six months ended June 30, 2010, all of our hedged transactions were probable of occurring.

Net deferred gain/(loss) recognized in AOCI on derivatives (effective portion) during the three and six months ended June 30, 2010 and June 30, 2009 are as follows (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Commodity derivatives	$ 18	$ (104)	$ 14	$ (82)
Foreign exchange derivatives		(4)	(1)	(2)
Interest rate derivatives	1		1	
Total	$ 19	$ (108)	$ 14	$ (84)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of June 30, 2010, we had a net broker payable of approximately $130 million (consisting of initial margin of $45 million reduced by $175 million of variation margin that had been returned to us). As of December 31, 2009, we had a net broker receivable of approximately $53 million (consisting of initial margin of $71 million reduced by $18 million of variation margin that had been returned to us).

At June 30, 2010 and December 31, 2009, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010. 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, which does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of June 30, 2010 (in millions)				Fair Value as of December 31, 2009 (in millions)			
Recurring Fair Value Measures[1]	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 186	$	$ 7	$ 193	$ 27	$	$ (31)	$ (4)
Interest rate derivatives			2	2			2	2
Foreign currency derivatives			(1)	(1)			1	1
Total	$ 186	$	$ 8	$ 194	$ 27	$	$ (28)	$ (1)

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash collateral amounts.

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The determination of the fair values above includes 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

There was no activity during the quarter within 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 but do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps and treasury locks. 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 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.

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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 classified as level 3 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Beginning Balance	$ (5)	$ 26	$ (28)	$ 74
Unrealized gains/(losses):				
Included in earnings [1]	5	8	12	54
Included in other comprehensive income	1	(21)	1	(22)
Settlements and derivatives entered into during the period	7	(18)	23	(111)
Ending Balance	$ 8	$ (5)	$ 8	$ (5)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 10	$ (8)	$ 9	$ (8)

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our consolidated statements of operations as supply and logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either supply and logistics segment revenues, purchases and related costs, or other income, net.

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 will therefore be offset by gains or losses on the underlying transactions.

Note 10 Commitments and Contingencies

Litigation

Pipeline Releases. 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. Approximately 980 and 4,200 barrels were recovered from the two respective sites. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $5 million to $6 million. The EPA has referred these two crude oil releases, as well as several other smaller releases, to 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) and have incorporated into our budget process the projected costs associated with potential injunctive remedies. 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, which commenced in July 2008. Statutory protections and our contractual rights of setoff covered substantially all of our pre-petition claims against SemCrude. In addition, 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. Certain SemCrude creditors have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude and its affiliates, and the continuation of such lien when SemCrude and its affiliates sold the oil to subsequent purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Certain of these actions have been removed to federal court and transferred to the U.S. Bankruptcy Court in Delaware. We will seek the same procedure with respect to all such actions so that they may be consolidated with our declaratory relief action in Bankruptcy Court. The aggregate amount subject to challenge is approximately $23 million. We intend to vigorously defend our contractual and statutory rights.

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

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at the PAT facility at Paulsboro, New Jersey. We estimate that the maximum potential cost to effectively remediate ranges up to $10 million although the NJDEP is asserting a much larger expenditure. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and/or 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 MTBE contamination.

NJDEP v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, Exxon and PAT to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. NJDEP environmental consultants have asserted a clean-up expense that is significantly larger than our estimate.

EPA v. RMPS. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of RMPS, a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities, performed at the request of customers, included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA s investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the CAA related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA has referred the matter to DOJ. We continue to engage in discussion with EPA, and to emphasize those factors that should mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have now been filed.

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. 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

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. For example, when the area around Lubbock, Texas received an unusually heavy rainfall in early July 2010, a branch of the Brazos River became swollen beyond flood stage. The unusually erosive power of the water undercut existing river banks and caused them to collapse. This phenomenon occurred at a river crossing for one of our 4-inch gathering lines. The combined force of the shifting mass of earth and rushing water severed the pipe, apparently allowing the release of crude oil into the river. We estimate that a maximum of 165 barrels may have been released. We also may discover environmental impacts from past releases that were previously unidentified. Whether current or past, damages and liabilities associated with 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. See Pipeline Releases above.

At June 30, 2010, our reserve for environmental liabilities totaled approximately $61 million, of which approximately $9 million is classified as short-term and $52 million is classified as long-term. At June 30, 2010, we have recorded receivables totaling approximately $5 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on known facts 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 may be in excess of the reserve 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 certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

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. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

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Note 11 Operating Segments

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

	Transportation	Facilities	Supply & Logistics	Total
Three Months Ended June 30, 2010				
Revenues:				
External Customers	$ 139	$ 84	$ 5,901	$ 6,124
Intersegment [1]	120	37		$ 157
Total revenues of reportable segments	$ 259	$ 121	$ 5,901	$ 6,281
Equity earnings of unconsolidated entities	$ 1	$	$	$ 1
Segment profit [2] [3]	$ 130	$ 70	$ 57	$ 257
Maintenance capital	$ 15	$ 5	$ 2	$ 22
Three Months Ended June 30, 2009				
Revenues:				
External Customers	$ 130	$ 53	$ 4,099	$ 4,282
Intersegment [1]	108	32		$ 140
Total revenues of reportable segments	$ 238	$ 85	$ 4,099	$ 4,422
Equity earnings of unconsolidated entities	$ 2	$ 3	$	$ 5
Segment profit [2] [3]	$ 114	$ 52	$ 78	$ 244
Maintenance capital	$ 16	$ 3	$ 3	$ 22

	Transportation	Facilities	Supply & Logistics	Total
Six Months Ended June 30, 2010				
Revenues:				
External Customers	$ 277	$ 158	$ 11,813	$ 12,248
Intersegment [1]	232	77	1	$ 310
Total revenues of reportable segments	$ 509	$ 235	$ 11,814	$ 12,558
Equity earnings of unconsolidated entities	$ 2	$	$	$ 2
Segment profit [2] [3]	$ 257	$ 129	$ 150	$ 536
Maintenance capital	$ 22	$ 8	$ 3	$ 33
Six Months Ended June 30, 2009				

Revenues:								
External Customers	$	254	$	100	$	7,231	$	7,585
Intersegment [(1)]		210		62			$	272
Total revenues of reportable segments	$	464	$	162	$	7,231	$	7,857
Equity earnings of unconsolidated entities	$	3	$	5	$		$	8
Segment profit [(2)] [(3)]	$	226	$	98	$	238	$	562
Maintenance capital	$	30	$	10	$	4	$	44

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. For further discussion, see Analysis of Operating Segments under Item 7 of our 2009 Annual Report on Form 10-K.

(2) Supply and logistics segment profit includes interest expense on contango inventory purchases of $5 million and $3 million for the three months ended June 30, 2010 and 2009, respectively, and $8 million and $5 million for the six months ended June 30, 2010 and 2009, respectively.

(3) The following table reconciles segment profit to net income attributable to Plains (in millions):

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	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Segment profit	$ 257	$ 244	$ 536	$ 562
Depreciation and amortization	(64)	(56)	(131)	(114)
Interest expense	(62)	(56)	(120)	(107)
Other income, net	2	2	(1)	5
Income tax benefit		2		1
Net income	133	136	284	347
Less: Net income attributable to noncontrolling interests	(2)		(2)	
Net income attributable to Plains	$ 131	$ 136	$ 282	$ 347

Note 12 Supplemental Condensed Consolidating Financial Information

For purposes of this Note 12, Plains is referred to as Parent. See Note 13 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further detail regarding subsidiaries classified as Guarantor Subsidiaries and subsidiaries 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, 2009.

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 (in millions):

Condensed Consolidating Balance Sheet

	As of June 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,935	$ 3,693	$ 255	$ (3,385)	$ 3,498