UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

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

(713) 646-4100
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes o 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 o 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 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

As of November 1, 2011, there were 149,376,937 Common Units outstanding.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	September 30, 2011 (unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14	$ 36
Restricted cash	—	20
Trade accounts receivable and other receivables, net	2,988	2,746
Inventory	1,086	1,491
Other current assets	102	88
Total current assets	4,190	4,381
PROPERTY AND EQUIPMENT	8,511	7,814
Accumulated depreciation	(1,240)	(1,123)
	7,271	6,691
OTHER ASSETS		
Goodwill	1,663	1,376
Linefill and base gas	535	519
Long-term inventory	136	154
Investments in unconsolidated entities	194	200
Other, net	454	382
Total assets	$ 14,443	$ 13,703

LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,287	$ 2,738
Short-term debt	619	1,326
Other current liabilities	220	151
Total current liabilities	4,126	4,215
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $14 and $12, respectively	4,261	4,363
Long-term debt under credit facilities and other	239	268
Other long-term liabilities and deferred credits	332	284
Total long-term liabilities	4,832	4,915
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
PARTNERS' CAPITAL		
Common unitholders (149,376,937 and 141,199,175 units outstanding, respectively)	4,830	4,234
General partner	126	108
Total partners' capital excluding noncontrolling interests	4,956	4,342
Noncontrolling interests	529	231
Total partners' capital	5,485	4,573
Total liabilities and partners' capital	$ 14,443	$ 13,703

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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(unaudited)		(unaudited)	
REVENUES				
Supply & Logistics segment revenues	$ 8,544	$ 6,179	$ 24,566	$ 17,992
Transportation segment revenues	140	144	428	421
Facilities segment revenues	153	91	396	249
Total revenues	8,837	6,414	25,390	18,662
COSTS AND EXPENSES				
Purchases and related costs	8,142	5,971	23,423	17,233
Field operating costs	217	176	638	510
General and administrative expenses	56	56	199	174
Depreciation and amortization	65	61	191	192
Total costs and expenses	8,480	6,264	24,451	18,109
OPERATING INCOME	357	150	939	553
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	1	9	3
Interest expense (net of capitalized interest of $7, $4, $18 and $13, respectively)	(62)	(64)	(190)	(183)
Other expense, net	(5)	(7)	(24)	(9)
INCOME BEFORE TAX	294	80	734	364
Current income tax benefit/(expense)	(7)	1	(25)	—
Deferred income tax benefit/(expense)	1	3	(3)	4
NET INCOME	288	84	706	368
Less: Net income attributable to noncontrolling interests	(7)	(3)	(18)	(5)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 281	$ 81	$ 688	$ 363
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 224	$ 40	$ 528	$ 241
GENERAL PARTNER	$ 57	$ 41	$ 160	$ 122
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.48	$ 0.28	$ 3.53	$ 1.73

DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.47	$ 0.28	$ 3.51	$ 1.72
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	149	136	147	136
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	150	137	148	137

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)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 706	$ 368
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	191	192
Equity compensation expense	56	50
Gain on sale of linefill	(19)	(18)
Net cash received for terminated interest rate or foreign currency hedging instruments	12	—
Loss on foreign currency revaluation	12	—
Other	9	6
Changes in assets and liabilities, net of acquisitions	785	(135)
Net cash provided by operating activities	1,752	463
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(758)	(197)
Change in restricted cash	20	—
Additions to property, equipment and other	(449)	(323)
Net cash received/(paid) for sales and purchases of linefill and base gas	(3)	20
Other investing activities	5	5
Net cash used in investing activities	(1,185)	(495)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on PAA’s revolving credit facility	(778)	(281)
Net borrowings/(repayments) on PNG’s credit agreements	(7)	222
Net borrowings/(repayments) on PAA’s hedged inventory facility	(450)	100
Proceeds from the issuance of senior notes	597	400
Repayments of senior notes	(200)	(175)
Net proceeds from the issuance of common units (Note 10)	503	—
Cash received for sale of noncontrolling interest in a subsidiary	370	268
Distributions paid to common unitholders (Note 10)	(427)	(382)
Distributions paid to general partner (Note 10)	(157)	(125)
Distributions to noncontrolling interests	(28)	(5)
Other financing activities	(5)	(1)
Net cash provided by/(used in) financing activities	(582)	21
Effect of translation adjustment on cash	(7)	(1)
Net decrease in cash and cash equivalents	(22)	(12)
Cash and cash equivalents, beginning of period	36	25
Cash and cash equivalents, end of period	$ 14	$ 13
Cash paid for interest, net of amounts capitalized	$ 204	$ 191
Cash paid for income taxes, net of amounts refunded	$ 1	$ 20

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 Units	Common Units Amount	General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners' Capital
			(unaudited)			
Balance, December 31, 2010	141	$ 4,234	$ 108	$ 4,342	$ 231	$ 4,573
Net income	—	528	160	688	18	706
Sale of noncontrolling interest in a subsidiary (Note 10)	—	63	1	64	306	370
Distributions	—	(427)	(157)	(584)	(28)	(612)
Issuance of common units	8	493	10	503	—	503
Issuance of common units under LTIP	—	15	—	15	—	15
Other comprehensive loss	—	(86)	(2)	(88)	—	(88)
Equity compensation expense		10	6	16	2	18
Balance, September 30, 2011	149	$ 4,830	$ 126	$ 4,956	$ 529	$ 5,485

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(unaudited)		(unaudited)	
Net income	$ 288	$ 84	$ 706	$ 368
Other comprehensive income/(loss)	(278)	17	(88)	37
Comprehensive income	10	101	618	405
Less: Comprehensive income attributable to noncontrolling interests	(7)	(3)	(18)	(5)
Comprehensive income attributable to Plains	$ 3	$ 98	$ 600	$ 400

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2010	$ (79)	$ 198	$ (1)	$ 118
Reclassification adjustments	235	—	—	235
Deferred loss on cash flow hedges, net of tax	(231)	—	—	(231)
Currency translation adjustment	—	(92)	—	(92)
Total period activity	4	(92)	—	(88)
Balance, September 30, 2011	$ (75)	$ 106	$ (1)	$ 30

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 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. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the development and operation of natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 14 for further detail of our three operating segments.

As used in this Form 10-Q and unless the context indicates otherwise, the terms "Partnership," "Plains," "PAA," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries. Also, 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
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights

EBITDA	=	Earnings before interest, taxes, depreciation and amortization
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
ICE	=	IntercontinentalExchange
IPO	=	Initial Public Offering
LIBOR	=	London Interbank Offered Rate
LPG	=	Liquefied petroleum gas and other natural gas-related products
LTIPs	=	Long-term incentive plans
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
MTBE	=	Methyl tertiary-butyl ether
Nexen	=	Nexen Holdings U.S.A. Inc.
NPNS	=	Normal purchases and normal sales
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
Pacific	=	Pacific Energy Partners, L.P.
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
PNGS	=	PAA Natural Gas Storage, LLC
RMPS	=	Rocky Mountain Pipeline System
SEC	=	Securities and Exchange Commission
SG Resources	=	SG Resources Mississippi, LLC
U.S. GAAP	=	Generally accepted accounting principles in the United States
USD	=	United States dollar
WTI	=	West Texas intermediate
WTS	=	West Texas sour

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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 2010 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 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. As discussed further below, 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 or total partners' capital. The condensed balance sheet data as of December 31, 2010 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 nine months ended September 30, 2011 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.

Revision of Prior Period Consolidated Statement of Cash Flows

During the second quarter of 2010, PNG completed its IPO of 13.5 million common units representing limited partner interests. Net proceeds received by PNG from the sale of the common units of approximately $268 million were presented in our financial statements for the quarter ended September 30, 2010 as cash flows from investing activities. Upon further evaluation, we now believe that this activity should have been presented as cash flows from financing activities. We have determined that the impact of this reclassification on our consolidated statement of cash flows for the nine months ended September 30, 2010 is not material.

The following captions within the prior period consolidated statement of cash flows were impacted (in millions):

	Amounts Previously Reported	As Revised
Net cash used in investing activities	$ (227)	$ (495)
Net cash provided by/(used in) financing activities	$ (247)	$ 21

Note 2—Recent Accounting Pronouncements

Other than as discussed below and in our 2010 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the nine months ended September 30, 2011 that are of significance or potential significance to us.

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for impairment tests performed during fiscal years (and interim periods within those years) that begin after December 15, 2010. We adopted this guidance on January 1, 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. We adopted this guidance on January 1, 2011. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. The fair value hierarchy consists of designation to one of three levels based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires a gross presentation of activities within the level 3 rollforward. This guidance was effective for annual and interim reporting periods beginning after December 15, 2010. We adopted this guidance on January 1, 2011. See Note 12 for additional disclosure. Our adoption did not have any material impact on our financial position, results of operations, or cash flows.

Accounting Pronouncements Not Yet Effective

In September 2011, the FASB issued guidance to simplify the goodwill impairment test by permitting entities to perform a qualitative assessment to determine whether further impairment testing is necessary. If qualitative factors indicate that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, an entity need not perform the two-step goodwill impairment test. This guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with earlier adoption permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued new guidance regarding the presentation of comprehensive income. This guidance requires entities to present reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement in which the components of net income and components of other comprehensive income are presented. It also eliminates the current option under U.S. GAAP to present components of other comprehensive income within the statement of changes in stockholders' equity. The components of comprehensive income will be required to be presented within either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance is effective for interim and annual periods beginning after December 15, 2011, with earlier adoption permitted. Since this issuance only impacts the presentation of such financial information, adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

In May 2011, the FASB issued guidance to amend certain measurement and disclosure requirements related to fair value in an effort to improve consistency with international reporting standards. This guidance is effective prospectively for interim and annual reporting periods beginning after December 15, 2011. Early adoption is not permitted. The adoption of this guidance is not expected to have a 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 September 30, 2011 and December 31, 2010, 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 approximately $6 million and $5 million at September 30, 2011 and December 31, 2010, respectively. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

At September 30, 2011 and December 31, 2010, we had received approximately $193 million and $197 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.

Note 4—Acquisitions

The following acquisition was accounted for using the acquisition method of accounting, and the purchase price was determined in accordance with such method.

Southern Pines Acquisition

On February 9, 2011, PNG acquired 100% of the equity interests in SG Resources from SGR Holdings, L.L.C. (the "Southern Pines Acquisition") for an aggregate purchase price of approximately $752 million in cash, net of cash acquired, which is subject to finalization of certain post-closing adjustments. The primary asset of SG Resources is the Southern Pines Energy Center ("Southern Pines"), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi. In connection with this

acquisition, PNG obtained financing through a private placement of PNG common units to third-party purchasers, and we purchased additional PNG common units. See Note 10 for further discussion.

The purchase price allocation related to the Southern Pines Acquisition is preliminary and subject to change, pending completion of internal valuation procedures primarily related to the valuation of intangible assets and the various components of the property and equipment acquired. The preliminary allocation of fair value to intangible assets below is comprised of a tax abatement valued at approximately $15 million and contracts valued at approximately $77 million, which have lives ranging from 2 to 10 years. Amortization of customer contracts under the declining balance method of amortization is estimated to be approximately $13 million, $14 million, $13 million, $11 million and $8 million for the five full or partial calendar years following the acquisition date, respectively. Goodwill or indefinite lived intangible assets will not be subject to depreciation or amortization, but will be subject to periodic impairment testing and, if necessary, will be written down to fair value should circumstances warrant. We expect to finalize our purchase price allocation during 2011. The preliminary purchase price allocation is as follows (in millions):

Description	Amount	Average Depreciable Life (in years)
Inventory	$ 14	N/A
Property and equipment, net	341	5 - 70
Base gas	3	N/A
Other working capital, net of cash acquired	1	N/A
Intangible assets	92	2 - 10
Goodwill	301	N/A
Total	$ 752	

Several factors contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired. Such factors include the strategic location of the Southern Pines facility, the limited alternative locations and the extended lead times required to develop and construct such facility, along with its operational flexibility, organic expansion capabilities and synergies anticipated to be obtained from combining Southern Pines with our existing asset base. Through September 30, 2011, we have incurred approximately $4 million of acquisition-related costs, which are included in general and administrative expenses in our condensed consolidated statement of operations. This acquisition is reflected within our facilities segment.

Also in connection with the Southern Pines Acquisition, PNG became the owner, with the ability to remarket in the future, and ultimate obligor of the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2009 and the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2010 (collectively, the "GO Bonds"). These were originally issued to fund the expansion of the Southern Pines facility. PNG remarketed the GO Bonds in August 2011 (see Note 7).

In May 2011, PNG entered into an agreement with the former owners of SG Resources with respect to certain outstanding issues and purchase price adjustments as well as the distribution of the remaining 5% of the purchase price that was escrowed at closing (totaling $37 million). Pursuant to this agreement, PNG received approximately $10 million and the balance was remitted to the former owners. Funds received by PNG have been and will continue to be used to fund anticipated facility development and other related costs identified subsequent to closing. Additionally, the parties executed releases of any existing and future claims, subject to customary carve-outs.

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Note 5—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 thousands of Mcf and total value in millions):

	September 30, 2011				December 31, 2010			
	Volumes	Unit of Measure	Total Value	Price/ Unit [1]	Volumes	Unit of Measure	Total Value	Price/ Unit [1]
Inventory								
Crude oil	5,302	barrels	$ 471	$ 88.83	14,132	barrels	$ 1,100	$ 77.84
LPG	8,917	barrels	580	$ 65.04	7,395	barrels	366	$ 49.49
Natural gas [2]	7,292	Mcf	28	$ 3.84	13	Mcf	—	$ 3.87
Other	N/A		7	N/A	N/A		25	N/A
Inventory subtotal			1,086				1,491	
Linefill and base gas								
Crude oil	9,259	barrels	487	$ 52.60	9,159	barrels	478	$ 52.19
Natural gas [2]	13,105	Mcf	46	$ 3.51	11,194	Mcf	37	$ 3.31
LPG	56	barrels	2	$ 35.71	77	barrels	4	$ 51.95
Linefill and base gas subtotal			535				519	
Long-term inventory								
Crude oil	1,733	barrels	128	$ 73.86	1,761	barrels	128	$ 72.69
LPG	150	barrels	8	$ 53.33	505	barrels	26	$ 51.49
Long-term inventory subtotal			136				154	
Total			$ 1,757				$ 2,164	

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

(2) The volumetric ratio of Mcf of natural gas to crude Btu equivalent is 6:1; thus, natural gas volumes can be approximately converted to barrels by dividing by 6.

Note 6 — Goodwill

The table below reflects our changes in goodwill for the period indicated (in millions):

Transportation	Facilities	Supply & Logistics	Total [1]

Balance, December 31, 2010	$ 640	$ 308	$ 428	$ 1,376
2011 Goodwill Related Activity:				
Southern Pines Acquisition [2]	—	301	—	301
Purchase accounting adjustments [2]	—	—	10	10
Foreign currency translation adjustments	(11)	—	(2)	(13)
Other	—	—	(11)	(11)
Balance, September 30, 2011	$ 629	$ 609	$ 425	$ 1,663

(1) As of September 30, 2011, we do not have any material accumulated impairment losses.

(2) Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation. This preliminary goodwill balance may be adjusted when the purchase price allocation is finalized.

We completed our annual goodwill impairment test (as of June 30) and determined that there was no impairment of goodwill.

Note 7—Debt

Debt consisted of the following (in millions):

	September 30, 2011	December 31, 2010
SHORT-TERM DEBT		
Credit Facilities [1]:		
Senior secured hedged inventory facility bearing a weighted-average interest rate of 1.4% and 2.1% at September 30, 2011 and December 31, 2010, respectively	$ 50	$ 500
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 1.6% and 0.7% at September 30, 2011 and December 31, 2010, respectively [2]	47	824
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% and 3.2% at September 30, 2011 and December 31, 2010, respectively [3]	18	—
4.25% senior notes due September 2012 [4]	500	—
Other	4	2
Total short-term debt	619	1,326
LONG-TERM DEBT		
Senior Notes:		
4.25% senior notes due September 2012 [4]	—	500
7.75% senior notes due October 2012 [5]	—	200
5.63% senior notes due December 2013	250	250
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021 [6]	600	—
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized discounts	(14)	(12)
Senior notes, net of unamortized discounts	4,261	4,363
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% and 3.2% at September 30, 2011 and December 31, 2010, respectively [3]	35	260
PNG GO Zone term loans, bearing a weighted-average interest rate of 1.5% at September 30, 2011	200	—
Other	4	8
Total long-term debt [2]	4,500	4,631
Total debt [7]	$ 5,119	$ 5,957

(1) During August 2011, we renewed and extended our principal bank credit facilities, including PNG's credit facility. See 'Credit Facilities' below for further discussion.

(2) We classify as short-term certain borrowings under our PAA senior unsecured revolving credit facility. These borrowings are primarily 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.

(3) PNG classifies as short-term debt any borrowings under the PNG senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of PNG's hedged natural gas inventory.

(4) Our $500 million 4.25% senior notes will mature September 2012 and thus are classified as short-term at September 30, 2011. The proceeds from these notes are being used to supplement capital available from our hedged inventory facility. At December 31, 2010, approximately $466 million had been used to fund hedged inventory and would have been classified as short-term debt if funded on our credit facilities. After these senior notes mature, we intend to use our recently renewed and expanded credit facilities to finance hedged inventory.

(5) On February 7, 2011, our $200 million, 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million, recorded to Other expense, net in our condensed consolidated statement of operations. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

(6) In January 2011, we completed the issuance of $600 million, 5.00% senior notes due 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities and for general partnership purposes.

(7) Our fixed-rate senior notes have a face value of approximately $4.8 billion and $4.4 billion as of September 30, 2011 and December 31, 2010, respectively. We estimate the aggregate fair value of these notes as of September 30, 2011 and December 31, 2010 to be approximately $5.3 billion and $4.7 billion, respectively. 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. We estimate that the carrying value of outstanding borrowings under our credit facilities approximates fair value as interest rates reflect current market rates.

Credit Facilities

During August 2011, we renewed and extended our principal bank credit facilities, as discussed further below. In connection with these transactions, we terminated a $500 million, 364-day senior unsecured credit facility that was scheduled to expire in January 2012.

PAA senior unsecured revolving credit facility. In August 2011, we entered into an unsecured revolving credit agreement with a committed borrowing capacity of $1.6 billion (including a $600 million Canadian sub-facility) which contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement provides for the issuance of letters of credit and has a maturity date in August 2016. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case, plus a margin based on our credit rating at the applicable time. This facility replaced a similar $1.6 billion senior unsecured revolving credit facility that was scheduled to mature in July 2012.

Senior secured hedged inventory facility. In August 2011, we replaced our previous $500 million senior secured hedged inventory facility that was scheduled to mature in October 2011 with a new $850 million senior secured hedged inventory facility (of which $250 million is available for the issuance of letters of credit) that expires in August 2013. Initial proceeds from the facility were used to refinance the outstanding balance of the previous facility, and subsequent proceeds from this facility will be used to finance purchased or stored hedged inventory. Subject to obtaining additional or increased lender commitments, the committed amount of this new facility may be increased to $1.35 billion. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable and will be repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case, plus a margin based on our credit rating at the applicable time.

Covenants and compliance. Both the PAA senior unsecured revolving credit facility and the senior secured hedged inventory facility have maximum debt-to-EBITDA coverage ratios of 5.00 to 1.00 (5.50 to 1.00 during an acquisition period, as defined in the respective credit agreements) and contain various covenants limiting our ability (or certain of our subsidiaries' ability) to, among other things:

- Grant liens on certain property;
- Incur indebtedness, including capital leases;
- Sell substantially all of our assets or enter into a merger or consolidation;
- Engage in transactions with affiliates;

- Enter into certain burdensome agreements;
- Enter into negative pledge arrangements; and
- Declare or make distributions on, or purchases or redemptions of, our equity interests if any default or event of default has occurred.

PNG senior unsecured credit agreement. In August 2011, PNG entered into a new $450 million, five-year senior unsecured credit agreement, which provides for (i) $250 million under a revolving credit facility, which may be increased at PNG's option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the "GO Zone term loans") pursuant to the purchase, at par, of the GO Bonds acquired by PNG in conjunction with the Southern Pines Acquisition (see Note 4). The revolving credit facility expires in August 2016, and the purchasers of the two GO Zone term loans have the right to put, at par, to PNG the GO Zone term loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. Borrowings under the revolving credit facility accrue interest, at PNG's election, on either the Eurodollar Rate or the Base Rate, in each case, plus an applicable margin. The GO Zone term loans accrue interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed.

PNG's new credit agreement contains covenants and events of default which are substantially consistent with those contained in PNG's previous credit facility. This new agreement restricts, among other things, PNG's ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit agreement contains restrictive covenants, including those that restrict PNG's ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of its assets or enter into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, require PNG to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also require that PNG maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement. This new PNG facility replaced a $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

Senior Notes

Our senior notes are co-issued, jointly and severally, by Plains All American Pipeline, L.P. and a 100%-owned consolidated finance subsidiary (neither of which have independent assets or operations). In August 2011, as permitted under the indentures governing the senior notes, PAA released the guarantees of each subsidiary guarantor in conjunction with the refinancing of our credit facilities. As such, our senior notes are no longer guaranteed by any of our subsidiaries.

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 September 30, 2011 and December 31, 2010, we had outstanding letters of credit of approximately $46 million and $75 million, respectively.

Note 8—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 nine months ended September 30, 2011 and 2010 (amounts in millions, except per unit data):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Numerator for basic and diluted earnings per limited partner unit:				
Net income attributable to Plains	$ 281	$ 81	$ 688	$ 363
Less: General partner's incentive distribution paid [1]	(52)	(40)	(149)	(117)
Subtotal	229	41	539	246
Less: General partner 2% ownership [1]	(5)	(1)	(11)	(5)
Net income available to limited partners	224	40	528	241
Adjustment in accordance with application of the two-class method for MLPs [1]	(3)	(2)	(8)	(5)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 221	$ 38	$ 520	$ 236
Denominator:				
Basic weighted average number of limited partner units outstanding	149	136	147	136
Effect of dilutive securities:				
Weighted average LTIP units [2]	1	1	1	1
Diluted weighted average number of limited partner units outstanding	150	137	148	137
Basic net income per limited partner unit	$ 1.48	$ 0.28	$ 3.53	$ 1.73
Diluted net income per limited partner unit	$ 1.47	$ 0.28	$ 3.51	$ 1.72

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

Note 9—Income Taxes

U.S. Federal and State Taxes

As an MLP, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although we are subject to state income taxes in some states, the impact to the three and nine months ended September 30, 2011 and 2010 was immaterial.

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Canadian Federal and Provincial Taxes

In 2010 and prior years, our Canadian operations were operated through a combination of corporate entities subject to Canadian federal and provincial taxes and a limited partnership which was treated as a flow-through entity for tax purposes. Due to changes in Canadian legislation and the Fifth Protocol to the U.S./Canada Tax Treaty, we restructured our Canadian investment on January 1, 2011. As of this date, all of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from Canada to other Plains entities are subject to Canadian withholding tax that is treated as a distribution to unitholders.

Note 10—Partners' Capital and Distributions

Noncontrolling Interests in a Subsidiary

As of September 30, 2011, noncontrolling interests consisted of the following: (i) an approximate 36% interest in PNG and (ii) a 25% interest in SLC Pipeline LLC.

During February 2011, in connection with the Southern Pines Acquisition, PNG completed a private placement of approximately 17.4 million PNG common units to third-party purchasers for net proceeds of approximately $370 million. In addition, we purchased approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million (collectively, "the PNG offering"). Also, during May 2011, a portion of the PNG Transaction Grants vested and was settled with 58,672 PNG units, which were owned by us. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further detail regarding the "*PNG Transaction Grants*." As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%. The following table sets forth our ownership changes in the limited partner units of PNG from December 31, 2010 to September 30, 2011 (units in millions):

	December 31, 2010	February 2011 PNG Issuance	Transaction Grants	September 30, 2011
		(in millions)		
PNG Units Owned by PAA:				
Common Units	18.1	10.2	(0.1)	28.2
Series A Subordinated Units	11.9	—	—	11.9
Series B Subordinated Units	13.5	—	—	13.5
Total PNG Units Owned by PAA	43.5	10.2	(0.1)	53.6

In addition to our limited partner interest, we also own the general partner's 2% interest and the incentive distribution rights in PNG.

In conjunction with the PNG offering, we recorded an increase in noncontrolling interest of $306 million and an increase to our partners' capital of approximately $64 million. The increases result from the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest resulting from this transaction.

The following table sets forth the impact of the changes in our ownership interest in PNG on our capital (in millions):

	For the Nine Months Ended September 30, 2011	2010
Net income attributable to Plains	$ 688	$ 363
Transfers to the noncontrolling interests:		
Increase in capital from sale of PNG units	64	101
Change from net income attributable to Plains and net transfers to the noncontrolling interest	$ 752	$ 464

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

	For the Nine Months Ended September 30, 2011	2010
Beginning balance	$ 231	$ 63
Sale of noncontrolling interests in a subsidiary	306	167
Net income attributable to noncontrolling interests	18	5
Distributions to noncontrolling interests	(28)	(5)
Equity compensation expense	2	2
Ending Balance	$ 529	$ 232

LTIP Vesting

In connection with the settlement of vested LTIP awards, we have issued 242,762 common units during 2011 with a fair value of approximately $15 million.

PAA Distributions

The following table details the distributions paid during or pertaining to the first nine months of 2011, net of reductions to the general partner's incentive distributions (in millions, except per unit amounts):

		Distributions Paid				Distributions per limited partner unit
		Common Units	General Partner			
Date Declared	Date Paid or To Be Paid		Incentive	2%	Total	
October 11, 2011	November 14, 2011 (1)	$ 149	$ 55	$ 3	$ 207	$ 0.9950
July 11, 2011	August 12, 2011	$ 147	$ 52	$ 3	$ 202	$ 0.9825
April 11, 2011	May 13, 2011	$ 145	$ 50	$ 3	$ 198	$ 0.9700
January 12, 2011	February 14, 2011	$ 135	$ 46	$ 3	$ 184	$ 0.9575

(1) Payable to unitholders of record at the close of business on November 4, 2011, for the period July 1, 2011 through September 30, 2011.

In conjunction with the closing of certain acquisitions, our general partner agreed to temporarily reduce the amounts due it as incentive distributions. The final $1 million of incentive distribution reductions related to these acquisitions will be applied to the November 2011 distribution. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further detail regarding our "*General Partner Incentive Distributions*."

PAA Equity Offerings

During the nine months ended September 30, 2011, we completed an equity offering of our common units as shown in the table below (in millions, except per unit data):

Date	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
March 2011 (1)	7,935,000	$ 64.00	$ 508	$ 10	$ (15)	$ 503

(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.

Note 11—Equity Compensation Plans

For discussion of our equity compensation awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K.

Our equity compensation 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, 2010	4.4	$ 41.69	1.0	$ 20.55
Granted	0.4	$ 54.40	—	$ —
Vested	(0.6)	$ 40.58	(0.1)	$ 23.62
Cancelled or forfeited	(0.2)	$ 41.93	—	$ —
Outstanding, September 30, 2011	4.0	$ 43.29	0.9	$ 20.46

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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Equity compensation expense	$ 10	$ 18	$ 56	$ 50
LTIP unit vestings (1)	$ 2	$ 1	$ 24	$ 26
LTIP cash settled vestings	$ —	$ 1	$ 18	$ 11
DER cash payments	$ 1	$ 1	$ 3	$ 3

(1) For the nine months ended September 30, 2011, approximately $2 million relates to unit vestings which were settled with PNG units.

Note 12—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. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on commodity price changes. 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 commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate 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 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.

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 only purchase product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not to acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. 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 operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of September 30, 2011, net derivative positions related to these activities included:

- An approximate 174,700 barrels per day net long position (total of 5.2 million barrels) associated with our crude oil purchases, which was unwound ratably during October 2011 to match monthly average pricing.

- A net short spread position averaging approximately 19,300 barrels per day (total of 8.2 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through January 2013. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- Approximately 10,000 barrels per day on average (total of 7.8 million barrels) of WTS/WTI crude oil basis swaps through December 2013, which hedge anticipated sales of crude oil (WTI). These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- Approximately 3,900 barrels per day on average (total of 1.4 million barrels) of LLS/WTI crude oil basis swaps January 2012 through December 2012, which hedge anticipated sales of crude oil. These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- Approximately 2,300 barrels per day on average (total of 0.4 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a fixed percentage of WTI and continue through March 2012. These derivatives are cross-commodity spreads between butane and WTI. Our use of these derivatives does not expose us to outright price risk.

Storage Capacity Utilization — We own approximately 72 million barrels of crude oil, LPG and refined products storage capacity other than that 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 September 30, 2011, we used derivatives to manage the risk of not utilizing approximately 3.5 million barrels per month of storage capacity through 2012. These positions are a combination of calendar spread options and 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. When we purchase and store inventory, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of September 30, 2011, we had derivatives totaling approximately 6.0 million barrels hedging our inventory. These positions are a combination of futures, swaps and option contracts.

We also purchase waterborne cargos of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of crude inventory. As of September 30, 2011, we had approximately 0.4 million barrels of crude oil derivatives hedging the anticipated sale of such 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 September 30, 2011, our PLA hedges included (i) a net short position consisting of crude oil futures and swaps for an average of approximately 1,700 barrels per day (total of 2.6 million barrels) through December 2015, (ii) a long put option position of approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 1.0 million barrels through December 2012.

Natural Gas Purchases and Sales — 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 September 30, 2011, we have a long swap position of approximately 2.0 Bcf through April 2013 related to anticipated base gas purchases. Additionally, our dedicated commercial optimization company captures short-term market opportunities by leasing a portion of our owned or leased storage capacity and engaging in related commercial optimization activities. We use various derivatives, including index and basis swaps, to hedge anticipated purchases and sales of natural gas by our commercial optimization company. As of September 30, 2011, we have a short swap position of approximately 14.3 Bcf through December 2011 related to anticipated sales of natural gas, and an approximate 5.9 Bcf long swap position through December 2011 related to anticipated purchases of natural gas.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion. 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 at fair value, with changes in fair value recognized in earnings.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of September 30, 2011, AOCI includes deferred losses of $114 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred gain related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

During the second and third quarters of 2011, we entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2015. The following table summarizes the terms of our forward starting interest rate swaps (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	4 forward starting swaps (10-year)	$ 200	6/15/2012	3.46%	Cash flow hedge
Anticipated debt offering	6 forward starting swaps (30-year)	$ 250	6/17/2013	4.21%	Cash flow hedge
Anticipated debt offering	2 forward starting swaps (30-year)	$ 50	6/16/2014	3.94%	Cash flow hedge
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge

During June 2011 and August 2011, PNG entered into three interest rate swaps to fix the interest rate on a portion of its outstanding debt. The swaps have an aggregate notional amount of $100 million with an average fixed rate of 0.95%. Two of these swaps terminate in June 2014 and the remaining swap terminates in August 2014. These swaps are designated as cash flow hedges.

Concurrent with our January 2011 senior notes issuance, we terminated three forward starting interest rate swaps. See Note 7 for additional disclosure. These swaps had an aggregate notional amount of $100 million and an average fixed rate of 3.6%. We received cash proceeds of $12 million associated with the termination of these swaps.

During July 2009, we entered into four interest rate swaps for which 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 terminated in September 2011, and two of the swaps will terminate in September 2012. The swaps that terminate in 2012 are designated as fair value hedges.

Currency Exchange Rate Risk Hedging

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 foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of September 30, 2011, AOCI includes net deferred gains of $14 million that relate to open and settled foreign currency derivatives that were designated for hedge accounting. These foreign currency derivatives hedge the cash flow variability associated with CAD-denominated interest payments on CAD-denominated intercompany notes as a result of changes in the exchange rate.

As of September 30, 2011, our outstanding foreign currency derivatives also include derivatives we use to hedge USD-denominated crude oil purchases and sales in Canada. In addition, 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 may 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.

The following table summarizes our open forward exchange contracts that exchange CAD for USD on a net basis (in millions):

	CAD	USD	Average Exchange Rate
2011	$ 44	$ 46	CAD $0.97 to US $1.00
2012	$ 15	$ 15	CAD $1.01 to US $1.00
2013	$ 9	$ 9	CAD $1.00 to US $1.00

Summary of Financial Impact

For derivatives that qualify as a cash flow hedge, changes in fair value of 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. For our interest rate swaps that qualify as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the underlying hedged item, attributable to the hedged risk, are recognized in earnings each period. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2011 and 2010 is as follows (in millions):

Location of gain/(loss)	Three Months Ended September 30, 2011			Three Months Ended September 30, 2010		
	Derivatives in Hedging Relationships (1)(2)	Derivatives Not Designated as a Hedge (4)	Total	Derivatives in Hedging Relationships (1)(2)	Derivatives Not Designated as a Hedge (4)	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ (1)	$ 50	$ 49	$ 7	$ (32)	$ (25)
Transportation segment revenues	—	—	—	1	—	1
Facilities segment revenues	3	—	3	—	—	—
Purchases and related costs	—	—	—	11	3	14
Field operating costs	—	(1)	(1)	—	—	—
Interest Rate Derivatives						
Interest expense	—	—	—	—	1	1
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	(6)	(6)	—	3	3
Other expense, net	3	—	3	—	(1)	(1)
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 5**	**$ 43**	**$ 48**	**$ 19**	**$ (26)**	**$ (7)**

Location of gain/(loss)	Nine Months Ended September 30, 2011			Nine Months Ended September 30, 2010		
	Derivatives in Hedging Relationships (1)(2)(3)(5)	Derivatives Not Designated as a Hedge (4)	Total	Derivatives in Hedging Relationships (1)	Derivatives Not Designated as a Hedge (4)	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ (237)	$ 90	$ (147)	$ (20)	$ 23	$ 3
Transportation segment revenues	—	—	—	2	—	2
Facilities segment revenues	(3)	1	(2)	(1)	1	—
Purchases and related costs	—	(1)	(1)	9	(10)	(1)
Interest Rate Derivatives						
Interest expense	1	—	1	(1)	3	2
Foreign Currency Derivatives						
Supply and Logistics segment revenues	—	(3)	(3)	—	—	—
Purchases and related costs	—	—	—	—	2	2
Other expense, net	5	—	5	—	(1)	(1)
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ (234)**	**$ 87**	**$ (147)**	**$ (11)**	**$ 18**	**$ 7**

(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 include gains of approximately $8 million for the three months ended September 30, 2011 that represent the ineffective portion of our cash flow hedges. This amount relates to commodity derivatives and was recognized in Supply and Logistics segment revenues during the period.
(3) Interest expense includes a net gain of approximately $1 million for the nine months ended September 30, 2011 associated with outstanding interest rate swaps, which are designated as a fair value hedge.
(4) Includes realized and unrealized gains or losses for derivatives not designated for hedge accounting during the period.
(5) Includes unrealized gains of approximately $3 million reclassified from AOCI to earnings during the period to offset a lower of cost or market adjustment relating to the carrying value of PNG's inventory.

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of September 30, 2011 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 26	Other current assets	$ (14)
	Other long-term assets	28	Other long-term assets	(1)
	Other current liabilities	72	Other current liabilities	(129)
			Other long-term liabilities	(1)
Interest rate derivatives	Other current assets	1	Other current liabilities	(21)
	Other current liabilities	1	Other long-term liabilities	(98)
Foreign exchange derivatives	Other current assets	4		
	Other long-term assets	1		
Total derivatives designated as hedging instruments		$ 133		$ (264)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 53	Other current assets	$ (16)
	Other long-term assets	8	Other long-term assets	(1)
	Other current liabilities	41	Other current liabilities	(38)
Foreign exchange derivatives	Other current assets	1	Other current liabilities	(6)
Total derivatives not designated as hedging instruments		$ 103		$ (61)
Total derivatives		$ 236		$ (325)

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 71	Other current assets	$ (70)
			Other long-term assets	(1)
			Other current liabilities	(1)
Interest rate derivatives	Other current assets	10		
Total derivatives designated as hedging instruments		$ 81		$ (72)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 11	Other current assets	$ (68)
	Other long-term assets	20		
	Other current liabilities	2	Other current liabilities	(10)
Interest rate derivatives	Other current assets	4		
	Other long-term assets	1		
Foreign currency derivatives	Other current assets	1		
Total derivatives not designated as hedging instruments		$ 39		$ (78)
Total derivatives		$ 120		$ (150)

As of September 30, 2011, there was a net loss of $69 million deferred in AOCI excluding tax effects. The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity 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 loss deferred in AOCI at September 30, 2011, we expect to reclassify a net gain of approximately $14 million to earnings in the next twelve months. Of the remaining deferred loss in AOCI, a net gain of approximately $16 million is expected to be reclassified to earnings prior to 2014 with the remaining deferred loss of $99 million being reclassified to earnings through 2045. 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.

During the three and nine months ended September 30, 2011, we reclassified a gain of approximately $1 million from AOCI to Other expense, net as a result of anticipated hedged transactions that are probable of not occurring. During the nine months ended September 30, 2011, we reclassified a gain of approximately $1 million from AOCI to Facilities segment revenues as a result of anticipated hedged transactions that are probable of not occurring. During the three and nine months ended September 30, 2010, all of our hedged transactions were probable of occurring. The net deferred gain/(loss), excluding tax effects, recognized in AOCI for derivatives during the three and nine months ended September 30, 2011 and 2010 are as follows (in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Commodity derivatives	$ (15)	$ (19)	$ (112)	$ (5)
Foreign currency derivatives	5	(1)	4	(2)
Interest rate derivatives	(123)	—	(117)	1
Total	$ (133)	$ (20)	$ (225)	$ (6)

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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 September 30, 2011, we had a net broker receivable of approximately $47 million (consisting of initial margin of $49 million reduced by $2 million of variation margin that had been returned to us). As of December 31, 2010, we had a net broker receivable of approximately $99 million (consisting of initial margin of $56 million increased by $43 million of variation margin that had been posted by us). At September 30, 2011 and December 31, 2010, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and December 31, 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 affects the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of September 30, 2011 (in millions)				Fair Value as of December 31, 2010 (in millions)			
Recurring Fair Value Measures [1]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ (9)	$ 1	$ 36	$ 28	$ (16)	$ —	$ (30)	$ (46)
Interest rate derivatives	—	(117)	—	(117)	—	—	15	15
Foreign currency derivatives	—	—	—	—	—	—	1	1
Total	$ (9)	$ (116)	$ 36	$ (89)	$ (16)	$ —	$ (14)	$ (30)

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

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

Included within level 2 of the fair value hierarchy are over-the-counter commodity derivatives and interest rate derivatives that are traded in active markets. The fair value of these derivatives is based on broker or dealer price quotations which are corroborated with market observable inputs.

Level 3

Included within level 3 of the fair value hierarchy are over-the-counter commodity derivatives that are traded in markets that are active but not sufficiently active to warrant level 2 classification in our judgment and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on broker or dealer price quotations or a valuation model. Our valuation models utilize inputs such as forward prices but do not involve significant management judgments.

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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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Beginning Balance	$ 10	$ 8	$ (14)	$ (28)
Unrealized gains/(losses):				
Included in earnings [1]	17	(16)	30	(2)
Included in other comprehensive income	3	3	2	3
Settlements	(2)	3	31	36
Derivatives entered into during the period	8	(5)	4	(16)
Transfers out of level 3	—	—	(17)	—
Ending Balance	$ 36	$ (7)	$ 36	$ (7)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 26	$ (22)	$ 35	$ (4)

(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 expense, net.

During the first quarter of 2011, we transferred interest rate and commodity derivatives with an aggregate fair value of $17 million from level 3 to level 2. This transfer resulted from the implementation of additional valuation procedures, using market observable inputs, to validate the broker or dealer price quotations used for fair value measurement. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

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 13—Commitments and Contingencies

Litigation

General. In the ordinary course of business, we are involved 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. Although we believe that our operations are presently in material compliance with applicable regulatory requirements, as we acquire and incorporate additional assets 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 whether such noncompliance initially developed before or after our acquisition.

SemCrude L.P., et al — Debtors/Associated Producers/Orange Creek Energy (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 and such claims have now been resolved. In separate actions, certain creditors of SemCrude have also filed state court proceedings 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 subsequently sold the oil to purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. We intend to vigorously defend our contractual and statutory rights.

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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 terminal facility in Paulsboro, New Jersey operated by Plains Product Terminals LLC (formerly Pacific Atlantic Terminals LLC) ("PPT"), which we acquired in the Pacific merger. Both ExxonMobil and GATX were prior owners of the terminal. We have obtained court approval of a Settlement Agreement with the State of New Jersey and Kinder Morgan (as successor in interest to GATX), which requires PPT and Kinder Morgan to install and implement an MTBE environmental restoration and monitoring program. We estimate the total cost of this project at approximately $3.0 million ($1.5 million to our share).

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, ExxonMobil and PPT to recover natural resources damages associated with, and to require remediation of, the contamination at our Paulsboro terminal facility. ExxonMobil and GATX have filed third-party demands against PPT, seeking indemnity and contribution. The natural resources damages have been settled and set at $1.1 million payable to the State of New Jersey. PPT's allocated share of this liability is $550,000, which will be paid in November 2011. The Settlement Agreement was approved by the Court in September 2011.

EPA v. Rocky Mountain Pipeline System. 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. After responding to the request, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act related to registration, sampling, recording and reporting in connection with such activities. EPA further alleged that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA referred the matter to the DOJ. Settlement discussions resulted in a Consent Decree effective as of July 12, 2011. The Decree includes provision for a penalty of $2.5 million, which was paid in the third quarter of 2011, and a commitment to an environmental project at an estimated cost of $250,000.

Bay Area Air Quality Management District ("BAAQMD"). During the time period from 2008 to the present, we have received from BAAQMD various Notices of Violation for alleged violations of California air emissions regulations at our Martinez terminal. We believe there are a number of mitigating factors applicable to the events in question and, based on communications with the BAAQMD as recently as October 2011, we expect that any fines and penalties ultimately assessed in respect of such matters will not exceed $165,000.

Pemex Exploración y Producción v. Big — Star Gathering Ltd L.L.P. et al. In a case filed in the Texas Southern District Court, Pemex Exploración y Producción ("PEP") alleges that certain parties stole condensate from pipelines and gathering stations and conspired with American companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but allegedly dealt in the condensate only after it had been laundered by others. PEP seeks actual damages, attorney's fees, and statutory penalties. At a hearing held on October 20, 2011, the Court ruled that Texas law (not Mexican law) governs the actions.

Environmental

General

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. 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 integrity management 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. These releases can result from unpredictable man-made or natural forces and may reach "navigable waters" or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At September 30, 2011, our reserve for environmental liabilities, including the reserve related to our Rainbow Pipeline release as discussed further below, totaled approximately $97 million, of which approximately $39 million was classified as short-term and $58 million was classified as long-term. At December 31, 2010, our reserve for environmental liabilities totaled approximately $66 million, of which approximately $10 million was classified as short-term and $56 million was classified as long-term. At September 30, 2011 and December 31, 2010, we had recorded receivables totaling approximately $51 million and $5 million, respectively, for amounts 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 information currently available to us 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.

Rainbow Pipeline Release

On April 29, 2011, we experienced a crude oil release on a remote section of our Rainbow Pipeline located in Alberta, Canada. Upon detection of the release, approximately 45 miles of the pipeline were isolated and depressurized and emergency response personnel were mobilized to conduct clean-up operations in cooperation with the Alberta Energy Resources Conservation Board ("ERCB"). We currently estimate that approximately 30,000 barrels of crude oil were released, which affected a site of approximately 40 acres located primarily on the pipeline right-of-way. Although clean-up operations and contamination monitoring continue, we completed the pipeline repair as well as additional regulatory requested pipeline inspections and information requests, and after receiving regulatory approval, restarted full operation of the pipeline on August 30, 2011.

We estimate that the aggregate total cost to clean-up and remediate the site, before insurance recoveries, is approximately $70 million. This estimate considers our prior experience in environmental investigation and remediation matters, as well as available data from, and in consultation with, our environmental specialists. While this estimate is subject to (i) uncertainties caused by the dynamic nature of site conditions, (ii) the range of remediation alternatives available and the corresponding costs of various clean-up methodologies and (iii) various other factors such as adverse weather and temperature changes, we currently are not aware of material adjustments that need to be made to this liability estimate. We believe we have established adequate reserves for all probable and reasonably estimable costs.

We currently expect that the clean-up and remediation efforts, excluding long-term site monitoring activities, will be substantially completed by the first quarter of 2012. We have accrued the total estimated costs to field operating costs on our condensed consolidated income statement. As of September 30, 2011, we have a remaining undiscounted gross environmental remediation liability for the release of $34 million. This liability is presented as a current liability within the caption "Accounts payable and accrued liabilities" on our condensed consolidated balance sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, to protect us against such environmental liabilities. This coverage is adequate to cover the current estimated total remediation costs, and management believes that this coverage is also adequate to cover any potential remediation costs that may be in excess of amounts currently identified. We therefore have recognized a receivable of $44 million as of September 30, 2011 for the portion of this liability that we believe is probable of recovery from insurance, net of deductibles. This receivable has been recognized as a current asset within the caption "Trade accounts receivable and other receivables, net" on our condensed consolidated balance sheet with the offset reducing operating expense on our condensed consolidated income statement.

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. For example, the market for hurricane-or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, and costs have increased substantially with the combination of premiums and deductibles for the 2010 renewal totaling 20% or more of the coverage limit.

For the last two years we have purchased a hurricane limit of $10 million to cover property and business interruption, representing substantially the level of insurance that was available. The coverage provided by these policies contained much stricter limitations than the insurance policies available prior to hurricanes Rita and Katrina. As a result of these conditions, we have decided not to purchase this coverage for 2011/12 and will self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have renewed at our historic levels. In addition, although we believe that we have established adequate reserves to the extent 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 14—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 September 30, 2011				
Revenues:				
External Customers	$ 140	$ 153	$ 8,544	$ 8,837
Intersegment [(1)]	160	38	1	199
Total revenues of reportable segments	$ 300	$ 191	$ 8,545	$ 9,036
Equity earnings in unconsolidated entities	$ 4	$ —	$ —	$ 4
Segment profit [(2)] [(3)]	$ 152	$ 95	$ 179	$ 426
Maintenance capital	$ 17	$ 6	$ 2	$ 25
Three Months Ended September 30, 2010				
Revenues:				
External Customers	$ 144	$ 91	$ 6,179	$ 6,414
Intersegment [(1)]	121	36	—	157
Total revenues of reportable segments	$ 265	$ 127	$ 6,179	$ 6,571
Equity earnings in unconsolidated entities	$ 1	$ —	$ —	$ 1
Segment profit [(2)] [(3)]	$ 137	$ 73	$ 2	$ 212
Maintenance capital	$ 21	$ 5	$ 3	$ 29

	Transportation	Facilities	Supply & Logistics	Total
Nine Months Ended September 30, 2011				
Revenues:				
External Customers	$ 428	$ 396	$ 24,566	$ 25,390
Intersegment [(1)]	436	120	1	557
Total revenues of reportable segments	$ 864	$ 516	$ 24,567	$ 25,947
Equity earnings in unconsolidated entities	$ 9	$ —	$ —	$ 9
Segment profit [(2)] [(3)]	$ 416	$ 259	$ 464	$ 1,139
Maintenance capital	$ 52	$ 16	$ 9	$ 77
Nine Months Ended September 30, 2010				
Revenues:				
External Customers	$ 421	$ 249	$ 17,992	$ 18,662
Intersegment [(1)]	353	113	1	467
Total revenues of reportable segments	$ 774	$ 362	$ 17,993	$ 19,129
Equity earnings in unconsolidated entities	$ 3	$ —	$ —	$ 3
Segment profit [(2)] [(3)]	$ 394	$ 202	$ 152	$ 748
Maintenance capital	$ 43	$ 13	$ 6	$ 62

(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 2010 Annual Report on Form 10-K.

(2) Supply and logistics segment profit includes interest expense (related to hedged inventory purchases) of $6 million and $5 million for the three months ended September 30, 2011 and 2010, respectively, and $17 million and $13 million for the nine months ended September 30, 2011 and 2010, respectively.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Segment profit	$ 426	$ 212	$ 1,139	$ 748
Depreciation and amortization	(65)	(61)	(191)	(192)
Interest expense	(62)	(64)	(190)	(183)
Other expense, net	(5)	(7)	(24)	(9)
Income tax (expense)/benefit	(6)	4	(28)	4
Net income	288	84	706	368
Less: Net income attributable to noncontrolling interests	(7)	(3)	(18)	(5)
Net income attributable to Plains	$ 281	$ 81	$ 688	$ 363

Note 15—Related Party Transactions

See Note 9 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of September 30, 2011, a subsidiary of Occidental Petroleum Corporation ("Oxy") owned approximately 35% of our general partner interest and had a representative on the board of directors of Plains All American GP LLC. During the three and nine months ended September 30, 2011 and 2010, we received sales and transportation storage revenues and purchased petroleum products from companies associated with Oxy. These transactions were consummated on terms equivalent to those that prevail in arm's-length transactions with our other counterparties. See detail below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Total revenues	$ 530	$ 732	$ 2,311	$ 1,425
Purchases and related costs	$ 90	$ 70	$ 255	$ 160

We currently have a netting arrangement with Oxy. Our gross receivables and payable amounts with affiliates of Oxy were as follows (in millions):

	September 30, 2011	December 31, 2010
Trade accounts receivable and other receivables	$ 221	$ 379
Accounts payable	$ 150	$ 124

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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 2010 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the condensed consolidated financial statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Our discussion and analysis herein includes the following:

- Executive Summary
- Acquisitions and Internal Growth Projects
- Results of Operations

- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

Executive Summary

Company Overview

We provide transportation, storage, terminalling and supply and logistics services with respect to crude oil, refined products and LPG. Through our general partner interest and majority equity ownership position in PNG, we also engage in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics.

Overview of Operating Results and Significant Activities

During the first nine months of 2011, our net income attributable to Plains was $688 million, which was a $325 million increase compared to the first nine months of 2010. This increase was driven by favorable results experienced within all three of our operating segments, but particularly within our supply and logistics segment. Overall this segment has benefited from the active development of crude oil and liquids-rich resource plays as well as from strong crude oil basis differentials and favorable market structure. Our facilities segment was primarily impacted by expansions to our asset base through acquisitions and our ongoing internal growth projects. Our transportation segment results were primarily driven by increased volumes in key production areas, tariff rate increases and favorable foreign currency exchange rates; however, such results were partially offset by the impact of a crude oil release on our Rainbow Pipeline. See the "Results of Operations" section below for further discussion and analysis of our operating segments. Additional key items impacting comparability between periods include:

- The completion of the Southern Pines Acquisition for approximately $752 million, net of cash acquired, by our subsidiary, PNG;
- The issuance of debt and equity for net proceeds of approximately $1.5 billion. This amount includes PNG's issuance of approximately 17.4 million common units to third parties for net proceeds of approximately $370 million, which was done in conjunction with the Southern Pines Acquisition;
- The redemption of our 7.75% senior notes that were maturing in 2012 for approximately $222 million. In conjunction with the early redemption of these notes, we recognized a loss of approximately $23 million in Other income/(expense), net within our condensed consolidated financial statements;

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- The increase in our income tax expense related to our Canadian operations as a result of Canadian tax legislation changes that became effective January 1, 2011.

Acquisitions and Internal Growth Projects

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

	Nine Months Ended September 30,	
	2011	2010
Acquisition capital (1)	$ 765	$ 166
Internal growth projects	380	236
Maintenance capital	77	62
Total	$ 1,222	$ 464

(1) Acquisition capital for the first nine months of 2011 primarily includes PNG's acquisition of SG Resources and its Southern Pines Energy Center natural gas storage facility. This acquisition is reflected within our facilities segment and is referred to herein as the Southern Pines Acquisition. See Note 4 to our condensed consolidated financial statements for further discussion regarding our acquisition activities.

Our internal growth projects primarily relate to the construction and expansion of pipeline systems and storage, terminal and gas processing facilities. The following table summarizes our more notable projects in progress during 2011 and the forecasted expenditures for the year ending December 31, 2011 (in millions):

Projects	2011
PAA Natural Gas Storage (multiple projects)	$ 93
Rainbow II Pipeline	44
Cushing - Phases IX - XI	41
Basile Gas Processing Facility	36
Ross Rail Project	32
Bumstead Facility	20

Bone Spring Expansion		19
Patoka Phase IV		16
Eagle Ford Project		14
Mid-Continent Project		14
Basin System Expansion		11
Ridgelawn Propane Storage		10
Other projects [1]		210
	$	560
Potential Adjustments for Timing/Scope Refinement [2]	- $30 +	$20
Total Projected Expansion Capital Expenditures	$530 -	$580
Maintenance Capital	$100 -	$110

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2010.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as regulatory approvals and weather.

Results of Operations

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) and other members of management evaluate segment performance based 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 included in Part IV of our 2010 Annual Report on Form 10-K for further discussion of how we evaluate segment performance.

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The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except for per unit amounts):

	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
	2011	2010	$	%	2011	2010	$	%
Transportation segment profit	$ 152	$ 137	$ 15	11%	$ 416	$ 394	$ 22	6%
Facilities segment profit	95	73	22	30%	259	202	57	28%
Supply & Logistics segment profit	179	2	177	8,850%	464	152	312	205%
Total segment profit	426	212	214	101%	1,139	748	391	52%
Depreciation and amortization	(65)	(61)	(4)	(7)%	(191)	(192)	1	1%
Interest expense	(62)	(64)	2	3%	(190)	(183)	(7)	(4)%
Other expense, net	(5)	(7)	2	29%	(24)	(9)	(15)	(167)%
Income tax benefit/(expense)	(6)	4	(10)	(250)%	(28)	4	(32)	(800)%
Net income	288	84	204	243%	706	368	338	92%
Less: Net income attributable to noncontrolling interests	(7)	(3)	(4)	(133)%	(18)	(5)	(13)	(260)%
Net income attributable to Plains	$ 281	$ 81	$ 200	247%	$ 688	$ 363	$ 325	90%
Net income attributable to Plains:								
Earnings per basic limited partner unit	$ 1.48	$ 0.28	$ 1.20	429%	$ 3.53	$ 1.73	$ 1.80	104%
Earnings per diluted limited partner unit	$ 1.47	$ 0.28	$ 1.19	425%	$ 3.51	$ 1.72	$ 1.79	104%
Basic weighted average units outstanding	149	136	13	10%	147	136	11	8%
Diluted weighted average units outstanding	150	137	13	9%	148	137	11	8%

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary measures used by management are adjusted earnings before interest, taxes, depreciation and amortization (“adjusted EBITDA”) and implied distributable cash flow (“DCF”).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as “Selected Items Impacting Comparability.” These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

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The following table sets forth non-GAAP financial measures that are reconciled from the most directly comparable measures as reported in accordance with GAAP (in millions except for per unit amounts):

	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
	2011	2010	$	%	2011	2010	$	%
Net income	$ 288	$ 84	$ 204	243%	$ 706	$ 368	$ 338	92%
Add:								
Depreciation and amortization	65	61	(4)	(7)%	191	192	1	1%
Income tax (benefit)/expense	6	(4)	(10)	(250)%	28	(4)	(32)	(800)%
Interest expense	62	64	2	3%	190	183	(7)	(4)%
EBITDA	$ 421	$ 205	$ 216	105%	$ 1,115	$ 739	$ 376	51%
Selected Items Impacting Comparability of EBITDA								
Gains/(losses) from other derivative activities [1]	31	(42)	73	174%	72	(3)	75	2,500%
Equity compensation expense [2]	(6)	(10)	4	40%	(40)	(34)	(6)	(18)%
Net loss on early repayment of senior notes	—	(6)	6	100%	(23)	(6)	(17)	(283)%
Loss on foreign currency revaluation [3]	(17)	—	(17)	N/A	(17)	—	(17)	N/A
Other [4]	(1)	(1)	—	—%	(5)	(2)	(3)	(150)%
Selected Items Impacting Comparability of EBITDA	$ 7	$ (59)	$ 66	112%	$ (13)	$ (45)	$ 32	71%
EBITDA	421	205	216	105%	1,115	739	376	51%
Selected Items Impacting Comparability of EBITDA	(7)	59	(66)	112%	13	45	(32)	71%
Adjusted EBITDA	$ 414	$ 264	$ 150	57%	$ 1,128	$ 784	$ 344	44%
Adjusted EBITDA	414	264	150	57%	1,128	784	344	44%
Interest expense	(62)	(64)	2	3%	(190)	(183)	(7)	(4)%
Maintenance capital	(25)	(29)	4	14%	(77)	(62)	(15)	(24)%
Current income tax benefit/(expense)	(7)	1	(8)	(800)%	(25)	—	(25)	N/A
Equity earnings in unconsolidated entities, net of distributions	2	1	1	100%	7	1	6	600%
Distributions to noncontrolling interests [5]	(12)	(5)	(7)	(140)%	(35)	(10)	(25)	(250)%
Other	—	—	—	—%	(1)	—	(1)	N/A
Implied DCF	$ 310	$ 168	$ 142	85%	$ 807	$ 530	$ 277	52%

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are presented with related derivative activity. See Note 12 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and hedging activities.

(2) Our total equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards are included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The compensation expense associated with these awards is shown as a selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for a comprehensive discussion regarding our equity compensation plans.

(3) Currently included as a selected item impacting comparability in periods with significant activity.

(4) Includes other immaterial selected items impacting comparability such as those impacting our subsidiary, PNG.

(5) Includes distributions that pertain to the current quarter's net income and are to be paid in the subsequent quarter.

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Analysis of Operating Segments

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. This segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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 September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Revenues [1]								
Tariff activities	$ 253	$ 240	$ 13	5%	$ 742	$ 697	$ 45	6%
Trucking	47	25	22	88%	122	77	45	58%
Total transportation revenues	300	265	35	13%	864	774	90	12%
Costs and Expenses [1]								
Trucking costs	(34)	(17)	(17)	(100)%	(88)	(52)	(36)	(69)%
Field operating costs (excluding equity compensation expense)	(97)	(88)	(9)	(10)%	(293)	(258)	(35)	(14)%
Equity compensation expense - operations [2]	(1)	(3)	2	67%	(6)	(7)	1	14%
Segment G&A expenses (excluding equity compensation expense)	(16)	(15)	(1)	(7)%	(49)	(48)	(1)	(2)%
Equity compensation expense - general and administrative [2]	(4)	(6)	2	33%	(21)	(18)	(3)	(17)%
Equity earnings in unconsolidated entities	4	1	3	300%	9	3	6	200%
Segment profit	$ 152	$ 137	$ 15	11%	$ 416	$ 394	$ 22	6%
Maintenance capital	$ 17	$ 21	$ 4	19%	$ 52	$ 43	$ (9)	(21)%
Segment profit per barrel	$ 0.54	$ 0.48	$ 0.06	13%	$ 0.50	$ 0.48	$ 0.02	4%

Average Daily Volumes (in thousands of barrels per day) [3]	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %
Tariff activities								
All American	38	37	1	3%	36	40	(4)	(10)%
Basin	443	401	42	10%	432	376	56	15%
Capline	121	260	(139)	(53)%	165	222	(57)	(26)%
Line 63/Line 2000	126	108	18	17%	114	110	4	4%
Salt Lake City Area Systems	142	143	(1)	(1)%	139	136	3	2%
Permian Basin Area Systems	408	385	23	6%	402	379	23	6%
Mid-Continent Area Systems	217	215	2	1%	217	213	4	2%
Manito	65	56	9	16%	66	59	7	12%
Rainbow	96	177	(81)	(46)%	132	189	(57)	(30)%
Rangeland	60	53	7	13%	57	51	6	12%
Refined products	104	110	(6)	(5)%	99	117	(18)	(15)%
Other	1,096	1,028	68	7%	1,063	997	66	7%
Tariff activities total	2,916	2,973	(57)	(2)%	2,922	2,889	33	1%
Trucking	109	99	10	10%	104	94	10	11%
Transportation segment total	3,025	3,072	(47)	(2)%	3,026	2,983	43	1%

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

(2) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the “Selected Items Impacting Comparability” section of the table as shown within the “Results of Operations-Non-GAAP Financial Measures” discussion above excludes this portion of the equity compensation expense. See Note 11 to our condensed consolidated financial statements for additional discussion of our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount. Transportation segment profit and segment profit per barrel were impacted by the following:

Operating Volumes and Revenues. As noted in the table above, our total transportation segment revenues, net of trucking costs, increased for both the quarter-over-quarter and year-over-year periods presented, while our volumes in the aggregate remained relatively consistent for these comparative periods.

However, noteworthy volume variances on our individual pipeline systems include (i) decreased volumes on our Rainbow System related to downtime associated with a pipeline release that was detected during April 2011 (see further discussion below), (ii) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply and unplanned refinery downtime, (iii) increased volumes on our Basin, Permian Basin Area Systems and Mid-Continent Area Systems driven by increased producer drilling in the surrounding regions and (iv) additional volumes of approximately 29,000 and 28,000 barrels per day for the three and nine months ended September 30, 2011, respectively, from the Robinson Lake pipeline acquired in connection with the Nexen acquisition in December 2010, which, in the Average Daily Volumes table above is included within "Other." Total transportation volumes were further impacted by increased trucking volumes for the three and nine months ended September 30, 2011 primarily resulting from (i) increased producer drilling and (ii) the hauling of barrels associated with downtime on the Rainbow Pipeline.

In addition to being impacted by the volumetric variances discussed above, our transportation segment revenues, net of trucking related costs, were also impacted by the following for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010:

- Rate Increases — Revenues were favorably impacted by increasing tariff rates on our Canadian pipelines, as well as increases in rates on our FERC-regulated pipelines due to upward indexing effective July 1, 2011. Such increases on our FERC-regulated pipelines for the nine-month period ended September 30, 2011 were partially offset by downward indexing that was effective July 1, 2010.

- Foreign Exchange Impact — Revenues and expenses from our Canadian-based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average Canadian dollar to U.S. dollar exchange rate for both the three-month and nine-month periods ended September 30, 2011 was $0.98 CAD: $1.00 USD compared to an average of $1.04 CAD: $1.00 USD for both the three-month and nine-month periods ended September 30, 2010. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted due to the appreciation of the Canadian dollar relative to the U.S. dollar by an estimated $4 million and $12 million for the three and nine months ended September 30, 2011, respectively, compared to the same 2010 periods.

- Loss Allowance Revenue — As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by approximately $1 million and $12 million for the three and nine months ended September 30, 2011, respectively, compared to the loss allowance revenue for the three and nine months ended September 30, 2010. These increases for both comparative periods were primarily due to a higher average realized price per barrel (including the impact of gains and losses from derivative activities), which were partially offset by lower volumes.

- Rainbow Pipeline System — As a result of a crude oil release that occurred in late April 2011, volumes and revenues for the Rainbow Pipeline System were reduced due to pipeline downtime on a portion of the system, and expenses increased due to repair and response costs. In an unrelated development occurring shortly after the release, we experienced additional downtime and expenses related to forest fires in the same region. As a result of these matters, for the three-month and nine-month periods ended September 30, 2011, we estimate revenues were reduced by approximately $11 million and $21 million, respectively. However, such unfavorable impacts were partially offset by the benefit of increased tariff rates on the system, as discussed further above. We resumed service on the impacted segment of the pipeline on August 30, 2011. See Note 13 to our condensed consolidated financial statements for further information regarding this pipeline release.

- Acquisitions — As discussed above, we acquired the Robinson Lake pipeline as part of the December 2010 Nexen acquisition. This newly acquired pipeline contributed approximately $2 million and $6 million, respectively, in revenues for the three and nine months ended September 30, 2011.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the three months ended September 30, 2011 compared to the three months ended September 30, 2010 consistent with the overall increase in revenue and activity in the segment. Field operating costs also increased for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The nine months ended September 30, 2011 includes the impact of approximately $13 million of environmental remediation expenses associated with the Rainbow Pipeline release. See Note 13 to our condensed consolidated financial statements for further information regarding this release. Excluding those costs, the increase for the nine month period was consistent with the increased activity in the segment and the remaining field operating costs are relatively consistent between periods on a per barrel basis.

Equity Compensation Expenses. Equity compensation expenses decreased for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 primarily due to a decrease in PAA unit price for the 2011 period, compared to an increase in unit price for the 2010 period. Such decreases were partially offset by an increase in expense associated with additional awards that have been deemed probable of occurring. A majority of our equity compensation awards contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. During 2011, we determined that a PAA distribution level of $4.10 per unit is probable of occurring.

Equity compensation expenses increased for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, primarily due to additional awards that have been deemed probable of occurring, as discussed further above. However, such increases were partially offset by a decrease in PAA unit price for the 2011 period, compared to an increase in unit price for the 2010 period.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital for the nine months ended September 30, 2011 compared to the same 2010 period is primarily due to increased spending on various pipeline integrity projects as well as timing of repairs between years.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities increased for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 primarily due to earnings from our 34% interest in White Cliffs Pipeline LLC, which we acquired in September 2010.

Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, natural gas and LPG, as well as LPG fractionation and isomerization services. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

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

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Storage and terminalling revenues [1]	$ 150	$ 127	$ 23	18%	$ 441	$ 362	$ 79	22%
Natural gas sales [2]	41	—	41	N/A	75	—	75	N/A
Storage related costs (natural gas related)	(5)	(5)	—	—%	(15)	(16)	1	6%
Natural gas costs [2]	(40)	—	(40)	N/A	(73)	—	(73)	N/A
Field operating costs (excluding equity compensation expense)	(38)	(37)	(1)	(3)%	(122)	(106)	(16)	(15)%
Equity compensation expense - operations [3]	—	—	—	N/A	(1)	(1)	—	—%
Segment G&A expenses (excluding equity compensation expense)	(11)	(9)	(2)	(22)%	(35)	(29)	(6)	(21)%
Equity compensation expense - general and administrative [3]	(2)	(3)	1	33%	(11)	(8)	(3)	(38)%
Segment profit	$ 95	$ 73	$ 22	30%	$ 259	$ 202	$ 57	28%
Maintenance capital	$ 6	$ 5	$ (1)	(20)%	$ 16	$ 13	$ (3)	(23)%
Segment profit per barrel	$ 0.38	$ 0.34	$ 0.04	12%	$ 0.36	$ 0.33	$ 0.03	9%

Volumes [4][5]	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	71	62	9	15%	69	61	8	13%
Natural gas storage (average monthly capacity in billions of cubic feet)	75	50	25	50%	69	46	23	50%
LPG processing (average throughput in thousands of barrels per day)	16	17	(1)	(6)%	14	14	—	—%
Facilities segment total (average monthly capacity in millions of barrels)	84	71	13	18%	81	69	12	17%

(1) Includes intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG's commercial optimization group, which was established in 2010.

(3) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the "Selected Items Impacting Comparability" section of the table as shown within the "Results of Operations-Non-GAAP Financial Measures" discussion above excludes this portion of the equity compensation expense. See Note 11 to our condensed consolidated financial statements for additional discussion of our equity compensation plans.

(4) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the period.

(5) Facilities segment total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 Mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

Facilities segment profit and segment profit per barrel were impacted by the following:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues (less storage related costs and natural gas purchases) and volumes increased for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010. The significant variances in revenues and average monthly volumes between the comparative periods are discussed below:

- Expansion Projects — Expansion projects that were completed in phases throughout 2010 and 2011 favorably impacted revenues and volumes during the comparative periods. These expansion projects were completed at some of our major storage and terminal locations, and we estimate that such projects increased our revenues by approximately $5 million to $10 million and $30 million to $35 million on a combined basis for the three and nine months ended September 30, 2011, respectively, compared to the same time periods of 2010. Such expansion projects at these facilities increased our total average monthly capacity by approximately 7 million barrels and 8 million barrels for both the three and nine months ended September 30, 2011, respectively, compared to the three and nine months ended September 30, 2010.

- Acquisitions — Revenues and volumes for the comparative period were favorably impacted by PNG's completion of the Southern Pines Acquisition, which closed on February 9, 2011. This acquisition contributed approximately $10 million and $26 million of additional revenues, net of storage related costs, for the three and nine months ended September 30, 2011, respectively.

- Other — Revenues for the three and nine months ended September 30, 2011 also increased as a result of volumetric gains, general escalations on existing leases and new lease contracts.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased in most categories during the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 consistent with the overall growth of the segment through expansion projects and the Southern Pines Acquisition as discussed above. Equity compensation expense decreased for the comparative three-month periods presented and increased for the comparative nine-month periods. A description of these variances is included within the Transportation Segment discussion above.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our supply and logistics segment volumes (which consist of lease gathered crude oil purchase volumes, LPG sales volumes, and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a balance that provides general stability in our margins, these margins are not fixed and will vary from period to period.

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The following table sets forth the operating results from our supply and logistics segment for the periods indicated:

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Revenues	$ 8,545	$ 6,179	$ 2,366	38%	$ 24,567	$ 17,993	$ 6,574	37%
Purchases and related costs [2]	(8,259)	(6,104)	(2,155)	(35)%	(23,794)	(17,625)	(6,169)	(35)%
Field operating costs (excluding equity compensation expense)	(84)	(49)	(35)	(71)%	(225)	(144)	(81)	(56)%
Equity compensation expense - operations [3]	—	(1)	1	100%	(1)	(1)	—	—%
Segment G&A expenses (excluding equity compensation expense)	(20)	(18)	(2)	(11)%	(67)	(56)	(11)	(20)%
Equity compensation expense - general and administrative [3]	(3)	(5)	2	40%	(16)	(15)	(1)	(7)%
Segment profit	$ 179	$ 2	$ 177	8,850%	$ 464	$ 152	$ 312	205%
Maintenance capital	$ 2	$ 3	$ 1	33%	$ 9	$ 6	$ (3)	(50)%
Segment profit per barrel	$ 2.28	$ 0.03	$ 2.25	7,500%	$ 1.98	$ 0.72	$ 1.26	175%

Average Daily Volumes [4] (in thousands of barrels per day)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %
Crude oil lease gathering purchases	748	622	126	20%	731	615	116	19%
LPG sales	77	73	4	5%	97	87	10	11%
Waterborne cargos	27	91	(64)	(70)%	28	79	(51)	(65)%
Supply & Logistics segment total	852	786	66	8%	856	781	75	10%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $6 million and $17 million for the three and nine months ended September 30, 2011, respectively, compared to $5 million and $13 million for the three and nine months ended September 30, 2010, respectively.

(3) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the "Selected Items Impacting Comparability" section of the table as

shown within the "Results of Operations-Non-GAAP Financial Measures" discussion above excludes this portion of the equity compensation expense.

(4) Calculated based on crude oil lease gathering purchased volumes, LPG sales volumes and waterborne cargo volumes.

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The NYMEX benchmark price of crude oil ranged from $76 to $101 per barrel and $71 to $83 per barrel during the three months ended September 30, 2011 and 2010, respectively, and from $76 to $115 per barrel and $64 to $87 per barrel during the nine months ended September 30, 2011 and 2010, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and sale, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those purchases and sales will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased in the three and nine months ended September 30, 2011 as compared to the three and nine months ended September 30, 2010, resulting both from higher commodity prices and increases in volumes experienced in the 2011 period.

Generally, we expect a base level of earnings from our supply and logistics segment that may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Our supply and logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our LPG marketing operations are weather-sensitive, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on financial performance. Supply and logistics segment profit and segment profit per barrel were impacted by the following:

Operating Revenues and Volumes. Revenues, net of purchases and related costs, for the three and nine months ended September 30, 2011, increased by approximately $211 million or 281% and $405 million or 110%, respectively, compared to the three and nine months periods ended September 30, 2010. Two of the principal drivers for this increase are (i) higher volumes due to increased production related to the active development of crude oil and liquids-rich resource plays and (ii) higher marketing margins related to production volumes exceeding existing pipeline takeaway capacity in certain regions and associated logistics challenges. Our results were most meaningfully impacted by increased drilling activities in the Bakken, Eagle Ford Shale, West Texas, Western Oklahoma and Texas Panhandle producing regions. Volumes also increased as a result of our December 2010 Nexen acquisition, which is primarily associated with the Bakken resource play. Additionally, our third-quarter 2011 revenues and waterborne cargo volumes benefited from purchases we made from the Strategic Petroleum Reserve. However, waterborne cargo volumes decreased over the comparable 2011 periods, which is primarily reflective of increased domestic production, as discussed above.

In addition, net revenues associated with our non-lease gathering activities increased for the 2011 periods over the comparative 2010 periods as a result of (i) a more favorable market structure, (ii) stronger crude oil quality differentials experienced within specific regions and (iii) our mark-to-market valuation of our derivatives, as shown in the table below (in millions):

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Variance	2011	2010	Variance
Gains/(losses) from derivative activities [1]	$ 31	$ (43)	$ 74	$ 73	$ (6)	$ 79

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are presented with related derivative activity. See Note 12 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and hedging activities.

Such results for both the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 were also favorably impacted by foreign currency adjustments. Revenues and expenses from our Canadian-based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. During 2011, revenues were favorably impacted by the appreciation of the Canadian dollar relative to the U.S. dollar. The average Canadian dollar to U.S. dollar exchange rate for both the three-month and nine-month periods ended September 30, 2011 was $0.98 CAD: $1.00 USD compared to an average of $1.04 CAD: $1.00 USD for both the three-month and nine-month periods ended September 30, 2010.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased in the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 consistent with our overall segment growth including (i) increased truck-hauled lease volumes and (ii) acquisitions such as the Nexen acquisition completed in the fourth quarter of 2010. Equity compensation expense decreased for the comparative three-month periods presented and increased for the comparative nine-month periods. A description of these variances is included within the Transportation Segment discussion above.

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Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased approximately $4 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 and was approximately flat for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. Included within 2011 depreciation expense is a decrease resulting from extensions of the depreciable lives of several of our crude oil and other storage facilities and pipeline systems. The extension of depreciable lives is based on an internal review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and technology. This decrease was offset by an increased amount of assets resulting from our acquisition activities, including Nexen and Southern Pines as well as various internal growth projects. Also included within depreciation expense for the nine months ended September 30, 2011 is an impairment of $4 million for assets taken out of service.

Interest Expense. Interest expense decreased by approximately $2 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 primarily due to lower interest expense incurred on our variable rate debt as well as increased capitalized interest. Interest expense increased, however, for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 by approximately $7 million. This increase is primarily due to the collective issuance of approximately $1.0 billion of senior notes (in January 2011 as well as in July 2010), which was partially offset by the retirement of $375 million of senior notes (in February 2011 and in September 2010) as well as by increased capitalized interest.

Other Expense, Net. Other expense, net was a loss of approximately $24 million for the nine-month period ended September 30, 2011, compared to a loss of approximately $9 million for the nine-month period ended September 30, 2010. The 2011 period was primarily impacted by the loss of approximately $23 million that was recognized in conjunction with the early redemption of our $200 million, 7.75% senior notes in February 2011. Similarly, the 2010 period was also primarily impacted by a loss incurred with the early redemption of our $175 million, 6.25% senior notes during September 2010, as well as by the loss on revaluation of contingent consideration related to our PNGS acquisition.

Income Tax Expense. Current income tax expense increased for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 primarily due to an increase in the level of taxable earnings in our entities subject to Canadian federal and provincial taxes. As a result of Canadian tax legislation changes, we restructured our Canadian investment on January 1, 2011 and all of our Canadian operations are subject to Canadian corporate tax at a rate of approximately 27% in 2011. Previously a portion of the activities were conducted in a flow-through entity that was not subject to entity-level taxation. We expect that our income tax expense will increase for the remainder of 2011 as compared to the 2010 historical periods. In addition, deferred tax expense increased for the comparable 2011 periods due to a decrease in book depreciation rates. Tax depreciation is now in excess of book depreciation.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flow from operations and (ii) borrowings under our credit facilities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses, interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and General Partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. At September 30, 2011, we had a working capital surplus of approximately $64 million and approximately $2.5 billion of liquidity available to meet our ongoing operational, investing and financing needs as noted below (in millions):

	As of September 30, 2011
Availability under PAA senior unsecured revolving credit facility	$ 1,542
Availability under PAA senior secured hedged inventory facility	768
Availability under PNG senior unsecured revolving credit facility	194
Cash and cash equivalents	14
Total	$ 2,518

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. See Item 1A. "Risk Factors" in our 2010 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources. Usage of our credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing all the various aspects of the Act have not yet been issued. Our current assessment is that we may have additional documentation and reporting requirements. We will continue to monitor the final rules and regulations as they develop.

Cash Flows from Operating Activities

For a comprehensive discussion of the primary drivers of our cash flow from operations, including the impact of varying market conditions and the timing of settlement of our derivative activities, see "Liquidity and Capital Resources—Cash Flow from Operations" under Item 7 of our 2010 Annual Report on Form 10-K.

Net cash flow provided by operating activities for the first nine months of 2011 was approximately $1.752 billion. The cash provided by operating activities reflects cash generated by our recurring operations, and is significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first nine months of 2011, we reduced our overall inventory levels. The reduction in our crude oil inventory levels is primarily due to liquidating a certain amount of inventory that had been stored in the contango market, which primarily began liquidating during the latter portion of the second quarter, as well as liquidating the inventory stored through our foreign cargo purchase activity, which occurred throughout the third quarter. This decrease was partially offset by increases in volumes and prices of our LPG inventory in preparation of end users' increased demand for heating requirements experienced during the winter months.

During the first nine months of 2010, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and prices and was primarily related to (i) our crude oil contango market storage activities, (ii) our LPG inventory in preparation of the end users' increased demand for heating requirements experienced during the winter months and (iii) our foreign cargo purchase activities.

Equity and Debt Financing Activities

Our financing activities primarily relate to (i) funding acquisitions and internal capital projects, (ii) short-term working capital and hedged inventory borrowings related to our LPG business, contango market activities and foreign import activities and (iii) refinancing of our debt maturities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Registration Statements and Equity and Debt Offerings

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities ("Traditional Shelf"). As of September 30, 2011, we had $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement ("WKSI Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our January 2011 senior notes offering and our March 2011 equity offering, as discussed further below, were both conducted under the WKSI Shelf.

PNG has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PNG to issue up to an aggregate of $1.0 billion of debt or equity securities. PNG also has access to a universal shelf registration statement, which provides PNG with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. PNG has not issued any securities under either of its shelf registration statements.

During August 2011, Vulcan Energy Corporation completed a secondary public offering of 7,500,000 common units representing limited partner interests in us at $61.10 per common unit. We did not receive any of the proceeds from the offering, and the number of PAA common units outstanding did not change as a result of this transaction. The secondary offering was not conducted under our Traditional Shelf or WKSI Shelf, but was conducted under a previously filed resale shelf registration statement.

PAA Equity Offering. In March 2011, we completed the issuance of 7,935,000 common units at $64.00 per unit for net proceeds of approximately $503 million. The net proceeds include our general partner's proportionate capital contribution and are reflected net of costs associated with the offering. We used the net proceeds to reduce outstanding borrowings under our credit facilities and for general partnership purposes. Amounts repaid under our credit facilities may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes.

PNG Equity Offering. In February 2011, in conjunction with the Southern Pines Acquisition, PNG completed a private placement of 17.4 million common units to third parties for net proceeds of approximately $370 million. See Notes 4 and 10 to our condensed consolidated financial statements for a discussion regarding this acquisition and related financing activities.

Senior Notes. In February 2011, our $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

In January 2011, we completed the issuance of $600 million of 5.00% senior notes due February 1, 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes.

Credit Agreements

During August 2011, we renewed and extended our principal bank credit facilities, as discussed further below. In connection with these transactions, we terminated a $500 million, 364-day senior unsecured credit facility that was scheduled to expire in January 2012.

PAA senior unsecured revolving credit facility. In August 2011, we entered into an unsecured revolving credit agreement with a committed borrowing capacity of $1.6 billion (including a $600 million Canadian sub-facility) which contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement provides for the issuance of letters of credit and has a maturity date in August 2016. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case, plus a margin based on our credit rating at the applicable time. This facility replaced a similar $1.6 billion senior unsecured revolving credit facility that was scheduled to mature in July 2012.

Senior secured hedged inventory facility. In August 2011, we replaced our previous $500 million senior secured hedged inventory facility that was scheduled to mature in October 2011 with a new $850 million senior secured hedged inventory facility (of which $250 million is available for the issuance of letters of credit) that expires in August 2013. Initial proceeds from the facility were used to refinance the outstanding balance of the previous facility, and subsequent proceeds from this facility are used to finance purchased or stored hedged inventory. Subject to obtaining additional or increased lender commitments, the committed amount of this new facility may be increased to $1.35 billion. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable and will be repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case, plus a margin based on our credit rating at the applicable time.

Covenants and compliance. Both the PAA senior unsecured revolving credit facility and the senior secured hedged inventory facility have maximum debt-to-EBITDA coverage ratios of 5.00 to 1.00 (5.50 to 1.00 during an acquisition period, as defined in the respective credit agreements) and contain various covenants limiting our ability (or certain of our subsidiaries' ability) to, among other things:

- Grant liens on certain property;

- Incur indebtedness, including capital leases;
- Sell substantially all of our assets or enter into a merger or consolidation;
- Engage in transactions with affiliates;
- Enter into certain burdensome agreements;
- Enter into negative pledge arrangements; and
- Declare or make distributions on, or purchases or redemptions of, our equity interests if any default or event of default has occurred.

PNG senior unsecured credit agreement. In August 2011, PNG entered into a new $450 million, five-year senior unsecured credit agreement, which provides for (i) $250 million under a revolving credit facility, which may be increased at PNG's option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the "GO Zone term loans) pursuant to the purchase, at par, of the GO Bonds acquired by PNG in conjunction with the Southern Pines Acquisition. The revolving credit facility expires in August 2016, and the purchasers of the two GO Zone term loans have the right to put, at par, to PNG the GO Zone term loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. Borrowings under the revolving credit facility accrue interest, at PNG's election, on either the Eurodollar Rate or the Base Rate, in each case, plus an applicable margin. The GO Zone term loans accrue interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed.

PNG's new credit agreement contains covenants and events of default which are substantially consistent with those contained in PNG's previous credit facility. This new agreement restricts, among other things, PNG's ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit agreement contains restrictive covenants, including those that restrict PNG's ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of its assets or enter into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, require PNG to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also require that PNG maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement. This new PNG facility replaced a $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

General. During the nine months ended September 30, 2011, we had net repayments on our credit agreements, which includes our revolving credit facilities and our GO Zone term loans, as well as our hedged inventory facility in the aggregate of approximately $1.2 billion. The net repayments resulted primarily from cash flows from operating activities, such as sales of crude oil that was liquidated during the period, as well as our debt and equity activities.

During the nine months ended September 30, 2010, we had net borrowings on our revolving credit facilities and our hedged inventory facility in the aggregate of approximately $41 million. The net borrowings resulted primarily from (i) increased levels of inventory resulting from the favorable contango market structure, (ii) funding our capital program and (iii) the redemption of our $175 million 6.25% senior notes. These borrowing activities were partially offset by repayments that were made on these credit facilities from funds received by the issuance of $400 million of 3.95% senior notes in July 2010.

For further discussion related to our credit facilities and long-term debt, see "Liquidity and Capital Resources—Credit Facilities and Long-Term Debt" under Item 7 of our 2010 Annual Report on Form 10-K.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See "Acquisitions and Internal Growth Projects" above and under Item 7 of our 2010 Annual Report on Form 10-K for further discussion of such capital expenditures.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On November 14, 2011, we will pay a quarterly distribution of $0.995 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 4.7%. Additionally, we paid approximately $28 million for distributions to our noncontrolling interests during the nine months ended September 30, 2011. See Note 10 to our condensed consolidated financial statements for details of distributions paid. Also, see Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" of our 2010 Annual Report on Form 10-K for additional discussion of distribution thresholds.

In conjunction with the closing of certain acquisitions, our general partner agreed to temporarily reduce the amounts due it as incentive distributions. The final $1 million of incentive distribution reductions will be applied to the November 2011 distribution.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity. See Item 1A. "Risk Factors" in our 2010 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources.

Contingencies

For a discussion of contingencies that may impact us, see Note 13 to our condensed consolidated financial statements.

Commitments

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

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of September 30, 2011 (in millions):

	2011	2012	2013	2014	2015	2016 and Thereafter	Total
Long-term debt and interest payments [1]	$ 72	$ 780	$ 515	$ 252	$ 793	$ 5,393	$ 7,805
Leases [2]	26	82	61	51	40	306	566
Other obligations [3]	42	79	42	11	5	77	256
Subtotal	140	941	618	314	838	5,776	8,627
Crude oil, refined products, natural gas and LPG purchases [4]	4,105	1,402	448	165	100	90	6,310
Total	$ 4,245	$ 2,343	$ 1,066	$ 479	$ 938	$ 5,866	$ 14,937

(1) Includes debt service payments, interest payments due on our senior notes, interest payments and the commitment fee on the PNG credit facility and the commitment fee on our PAA revolving credit facility. Although there is an outstanding balance on our PAA revolving credit facility at September 30, 2011, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for (i) storage, (ii) rights-of-way, (iii) office rent, (iv) pipeline assets, (v) compression services and (vi) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $98 million related to derivative activity included in Crude oil, refined products, natural gas and LPG purchases.

(4) Amounts are based on estimated volumes and market prices based on average activity during September 2011. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include, as applicable, levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligations for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At September 30, 2011 and December 31, 2010, we had outstanding letters of credit of approximately $46 million and $75 million, respectively.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Item 7 of our 2010 Annual Report on Form 10-K.

Forward-Looking Statements

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

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

- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- the effectiveness of our risk management activities;

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

- shortages or cost increases of supplies, materials or labor;

- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

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

- the effects of competition;

- interruptions in service on third-party pipelines;

- increased costs or lack of availability of insurance;

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

- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;

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

- factors affecting demand for natural gas and natural gas storage services and rates;

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

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors, described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read "Risks Factors" discussed in Item 1A of our 2010 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2010 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 10 to our condensed consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

The fair value of our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil:			
Futures contracts	$ (37)	$ 10	$ (10)
Swaps and options contracts	55	$ (14)	$ 13
LPG and other:			
Swaps and options contracts	10	$ (32)	$ 32
Total Fair Value	$ 28		

Interest Rate Price Risk

The fair value of our outstanding interest rate swap agreements as of September 30, 2011 was a net liability of approximately $117 million. A 10% increase in interest rates would result in a net liability of approximately $81 million. A 10% decrease in interest rates would result in a net liability of approximately $153 million.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." Our DCP is designed to ensure that (i) information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 ("the Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

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

Changes in Internal Control over Financial Reporting

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

Certifications

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

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption "Litigation" in Note 13 to our condensed consolidated financial statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2010 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. [REMOVED AND RESERVED]

Item 5. OTHER INFORMATION

None.

Item 6. **EXHIBITS**

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	—	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	—	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).

3.6	—	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	—	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.10	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.11	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.12	—	Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).
3.13	—	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).
3.14	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).

4.6	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
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4.8	—	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	—	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	—	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	—	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	—	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	—	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	—	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.19	—	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).

4.20	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	—	Credit Agreement dated as of August 19, 2011, among Plains All American Pipeline, L.P., as Borrower; certain subsidiaries of Plains All American Pipeline, L.P. from time to time party thereto, as Designated Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 25, 2011).
10.2	—	Third Amended and Restated Credit Agreement dated as of August 19, 2011, among Plains Marketing, L.P., as Borrower; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent and L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 25, 2011).

12.1 †	—	Computation of Ratio of Earnings to Fixed Charges
31.1 †	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
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101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
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101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

† Filed herewith

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SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Date: November 4, 2011

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

Date: November 4, 2011

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

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101.PRE[†]	—	XBRL Taxonomy Extension Presentation Linkbase Document

[†] Filed herewith

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions)

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010	2009	2008	2007	2006
EARNINGS [1]						
Pre-tax income from continuing operations before noncontrolling interest and income from equity investees	$ 725	$ 510	$ 572	$ 430	$ 350	$ 278
add: Fixed charges	246	321	283	264	233	149
add: Distributed income of equity investees	16	9	7	10	2	1
add: Amortization of capitalized interest	1	1	1	1	—	—
less: Capitalized interest	(18)	(16)	(12)	(17)	(14)	(6)
Total Earnings	$ 970	$ 825	$ 851	$ 688	$ 571	$ 422
FIXED CHARGES [1]						
Interest expensed and capitalized [2]	$ 225	$ 281	$ 247	$ 233	$ 220	$ 141
Amortization of debt expense	7	8	7	4	3	3
Portion of rent expense related to interest (33.33%)	14	32	29	27	10	5
Total Fixed Charges	$ 246	$ 321	$ 283	$ 264	$ 233	$ 149
RATIO OF EARNINGS TO FIXED CHARGES [3]	3.95x	2.57x	3.00x	2.60x	2.45x	2.83x

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. "Fixed charges" represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on leases deemed to be the equivalent of interest.

(2) Includes interest costs attributable to borrowings for inventory stored in a contango market of $17 million for the nine months ended September 30, 2011 and $17 million, $11 million, $21 million, $44 million and $49 million for each of the years ended December 31, 2010, 2009, 2008, 2007 and 2006, respectively.

(3) Ratios may not recalculate due to rounding.

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 4, 2011

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Al Swanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 4, 2011

/s/ AL SWANSON

Al Swanson
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended September 30, 2011 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GREG L. ARMSTRONG
Name: Greg L. Armstrong
Date: November 4, 2011

EXHIBIT 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended September 30, 2011 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ AL SWANSON
Name: Al Swanson
Date: November 4, 2011