PACIFIC ENERGY PARTNERS LP
Form 10-Q
November 06, 2006

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, 2006

OR

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission File Number 1-31345

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**68-0490580**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5900 Cherry Avenue
Long Beach, CA 90805-4408

(Address of principal executive offices)

(562) 728-2800

(Registrant s telephone number, including area code)

None

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer x Non-accelerated filer o

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at October 31, 2006
Common Units	34,074,032
Subordinated Units	5,232,500

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

PACIFIC ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006 (in thousands)	**December 31, 2005**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,715	$ 18,064
Crude oil sales receivable	153,604	95,952
Transportation and storage accounts receivable	27,268	30,100
Canadian goods and services tax receivable	9,771	8,738
Insurance proceeds receivable, net	4,581	9,052
Due from related parties	28	
Crude oil and refined products inventory	46,012	20,192
Prepaid expenses	4,451	7,489
Other	5,796	2,528
Total current assets	265,226	192,115
Property and equipment, net	1,252,750	1,185,534
Intangible assets, net	67,639	69,180
Investment in Frontier	8,651	8,156
Other assets, net	17,957	21,467
	$ 1,612,223	$ 1,476,452
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,346	$ 42,409
Accrued crude oil purchases	152,284	96,651
Line 63 oil release reserve	3,194	5,898
Accrued interest	7,381	4,929
Other	7,955	6,300
Total current liabilities	204,160	156,187
Senior notes and credit facilities, net	669,163	565,632
Deferred income taxes	32,560	35,771
Environmental liabilities	14,257	16,617
Other liabilities	3,159	4,006
Total liabilities	923,299	778,213
Commitments and contingencies (note 6)		
Partners capital:		
Common unitholders (34,074,032 and 31,448,931 units issued and outstanding at September 30, 2006 and December 31, 2005, respectively)	640,232	644,589
Subordinated unitholders (5,232,500 and 7,848,750 units issued and outstanding at September 30, 2006 and December 31, 2005, respectively)	14,529	24,758
General Partner interest	12,219	12,535
Undistributed employee long-term incentive compensation	467	
Accumulated other comprehensive income	21,477	16,357
Net partners capital	688,924	698,239
	$ 1,612,223	$ 1,476,452

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(in thousands, except per unit amounts)			
Revenues:				
Pipeline transportation revenue	$ 36,995	$ 27,283	$ 105,652	$ 83,067
Storage and terminaling revenue	23,467	9,731	65,420	30,923
Pipeline buy/sell transportation revenue	10,010	11,683	31,136	28,905
Crude oil sales, net of purchases of $421,276 and $188,901 for the three months ended September 30, 2006 and 2005 and $1,031,185 and $425,733 for the nine months ended September 30, 2006 and 2005	9,924	5,823	27,453	13,647
	80,396	54,520	229,661	156,542
Cost and Expenses:				
Operating (which excludes $586 of compensation expense for the nine months ended September 30, 2005 reported in accelerated long-term incentive plan compensation expense)	34,046	25,019	99,120	72,065
General and administrative (which excludes $2,529 of compensation expense for the nine months ended September 30, 2005 reported in accelerated long-term incentive plan compensation expense)	5,649	4,115	18,236	12,987
Depreciation and amortization	10,398	6,560	30,692	19,695
Merger costs (note 2)	1,112		4,529	
Accelerated long-term incentive plan compensation expense (note 7)				3,115
Line 63 oil release costs (note 6)				2,000
Reimbursed general partner transaction costs (note 5)				1,807
	51,205	35,694	152,577	111,669
Share of net income of Frontier	373	516	1,246	1,363
Operating income	29,564	19,342	78,330	46,236
Interest expense	(10,853)	(6,237)	(30,029)	(17,679)
Interest and other income	720	494	1,455	1,387
Income before income taxes	19,431	13,599	49,756	29,944
Income tax (expense) benefit:				
Current	(485)	(1,411)	(2,288)	(1,898)
Deferred (note 3)	289	(22)	4,824	(239)
	(196)	(1,433)	2,536	(2,137)
Net income	$ 19,235	$ 12,166	$ 52,292	$ 27,807
Net income (loss) for the general partner interest	$ 347	$ 243	$ 720	$ (1,215)
Net income for the limited partner interests	$ 18,888	$ 11,923	$ 51,572	$ 29,022
Basic net income per limited partner unit	$ 0.48	$ 0.39	$ 1.31	$ 0.97
Diluted net income per limited partner unit	$ 0.48	$ 0.39	$ 1.31	$ 0.96
Weighted average limited partner units outstanding:				
Basic	39,307	30,761	39,305	30,051
Diluted	39,321	30,762	39,332	30,089

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(Unaudited)

	Limited Partner Units		Limited Partner Amounts		General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income	Total
	Common (in thousands)	Subordinated	Common	Subordinated				
Balance, December 31, 2005	31,449	7,849	$ 644,589	$ 24,758	$ 12,535	$	$ 16,357	$ 698,239
Net income			41,917	9,655	720			52,292
Distribution to partners			(53,159)	(13,264)	(2,291)			(68,714)
Employee compensation under LB Pacific, LP Option Plan					1,250			1,250
Employee compensation under long-term incentive plan						782		782
Issuance of common units pursuant to long-term incentive plan	9		265		5	(315)		(45)
Foreign currency translation adjustment							4,908	4,908
Change in fair value of crude oil and foreign currency hedging contracts							212	212
Conversion of subordinated units to common units	2,616	(2,616)	6,620	(6,620)				
Balance, September 30, 2006	34,074	5,233	$ 640,232	$ 14,529	$ 12,219	$ 467	$ 21,477	$ 688,924

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(in thousands)			
Net income	$ 19,235	$ 12,166	$ 52,292	$ 27,807
Change in fair value of crude oil and hedging derivatives	271	303	531	(502)
Change in fair value of foreign currency hedging derivatives	115		(319)	
Change in foreign currency translation adjustment	(236)	5,678	4,908	3,377
Comprehensive income	$ 19,385	$ 18,147	$ 57,412	$ 30,682

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2006 (in thousands)	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 52,292	$ 27,807
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	30,692	19,695
Amortization of debt issue costs	1,847	1,424
Non-cash employee compensation under long-term incentive plan	782	2,886
Non-cash employee compensation under the LB Pacific, LP Option Plan	1,250	
Deferred tax expense (benefit)	(4,824)	239
Share of net income of Frontier	(1,246)	(1,363)
Other adjustments	(1,665)	58
Distributions from Frontier, net	622	1,317
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(55,829)	(68,206)
Transportation and storage accounts receivable	3,161	909
Insurance proceeds receivable	6,695	(8,829)
Crude oil and refined products inventory	(25,508)	(2,742)
Other current assets and liabilities	(3,771)	(3,757)
Accounts payable and other accrued liabilities	(5,076)	27,354
Accrued crude oil purchases	54,400	64,917
Line 63 oil release reserve	(4,929)	5,411
Other non-current assets and liabilities	598	(1,465)
NET CASH PROVIDED BY OPERATING ACTIVITIES	49,491	65,655
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(2,365)	(461,165)
Additions to property and equipment	(67,522)	(27,265)
Additions to pipeline linefill and minimum tank inventory	(16,106)	-
Other	181	-
NET CASH USED IN INVESTING ACTIVITIES	(85,812)	(488,430)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses		289,122
Capital contributions from the general partner		8,569
Proceeds from credit facilities	182,094	203,291
Net proceeds from senior notes offering		170,997
Repayment of credit facilities	(81,463)	(195,661)
Deferred financing costs		(4,676)
Distributions to partners	(68,714)	(46,224)
Issuance of common units pursuant to exercise of unit options		707
Related parties	(28)	(1,171)
NET CASH PROVIDED BY FINANCING ACTIVITIES	31,889	424,954
Effect of exchange rates on cash	83	213
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,349)	2,392
CASH AND CASH EQUIVALENTS, beginning of reporting period	18,064	23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 13,715	$ 25,775

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2006
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Pacific Energy Partners, L.P. and its subsidiaries (collectively, the Partnership) are engaged principally in the business of gathering, transporting, storing and distributing crude oil, refined products and other related products. The Partnership generates revenue primarily by transporting such commodities on its pipelines, by leasing storage capacity in its storage tanks, and by providing other terminaling services. The Partnership also buys and sells crude oil, activities that are generally complementary to its other crude oil operations. The Partnership conducts its business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

The Partnership is managed by its general partner, Pacific Energy GP, LP, a Delaware limited partnership, which is managed by its general partner, Pacific Energy Management LLC (PEM), a Delaware limited liability company. Thus, the officers and board of directors of PEM manage the business affairs of Pacific Energy GP, LP and the Partnership. References to the General Partner refer to Pacific Energy GP, LP and/or PEM, as the context indicates; and Board of Directors refers to the board of directors of PEM.

The unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and with Securities and Exchange Commission (SEC) regulations. Accordingly, these statements have been condensed and do not include all of the information and footnotes required for complete financial statements. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the nine months ended September 30, 2006 are not necessarily indicative of the results of operations for the full year. All significant intercompany balances and transactions have been eliminated during the consolidation process.

The condensed consolidated financial statements include the ownership and results of operations of the assets acquired from Valero, L.P., since the acquisition of these assets on September 30, 2005. The assets acquired from Valero, L.P. have been integrated into our West Coast and Rocky Mountain Business Units as Pacific Atlantic Terminals and the Rocky Mountain Products Pipeline.

These financial statements should be read in conjunction with the Partnership s audited consolidated financial statements and notes thereto included in the Partnership s annual report on Form 10-K and Form 10-K/A for the year ended December 31, 2005. Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to the current year presentation.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised December 2004), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005. The adoption of SFAS 123R on January 1, 2006 did not have a material impact on the Partnership s consolidated financial statements. See Notes 5 and 7 to the condensed consolidated financial statements for more details on share-based compensation.

In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The adoption of EITF 04-13 did not have a material impact on the Partnership s consolidated financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 will apply to the Partnership s Canadian subsidiaries, which are taxable entities in Canada. The Partnership is in the process of determining the impact of FIN 48 on its financial statements, but does not expect it to have a material impact. FIN 48 is effective for the Partnership as of the beginning of the first fiscal year beginning on January 1, 2007.

In June 2006, the EITF issued Issue No. 06-3 (EITF 06-3), *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).* The issues addressed by the EITF are (i) whether the scope of this Issue should include (a) all nondiscretionary amounts assessed by governmental authorities, (b) all nondiscretionary amounts assessed by governmental authorities in connection with a transaction with a customer, or (c) only sales, use, and value added taxes, and (ii) how taxes assessed by a governmental authority within the scope of this issue should be presented in the income statement (that is, gross versus net presentation). EITF 06-3 is effective for interim and annual financial periods beginning after December 15, 2006. The Partnership is in the process of determining the impact of EITF 06-3 on its financial statements, but does not expect it to have a material impact.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements (SFAS 157).* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements in those accounting pronouncements. Accordingly, SFAS 157 does not require any new fair value measurements. However, the Partnership is in the process of determing what impact the application of SFAS 157 will have on its current fair value practices. The Partnership does not expect the application of SFAS 157 to have a material impact. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current year Financial Statements* (SAB 108), which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. The guidance is effective for fiscal years beginning after November 15, 2006 and it allows a one-time transitional cumulative effect adjustment to beginning-of-year retained earnings at the first fiscal year ending after November 15, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The Partnership is currently evaluating the impact, if any, of adopting SAB 108 on its consolidated financial statements.

2. PROPOSED MERGER WITH PLAINS ALL AMERICAN PIPELINE, L.P.

On June 12, 2006, the Partnership announced that it had entered into an Agreement and Plan of Merger with Plains All American Pipeline, L.P. (PAA), Plains AAP, L.P., Plains All American GP LLC (PAA GP LLC), PEM, and Pacific Energy GP, LP, pursuant to which the Partnership will be merged with and into PAA. In the merger, each common unitholder of the Partnership, except LB Pacific, LP (LB Pacific), the owner of the Partnership s General Partner, will receive 0.77 common units of PAA for each common unit of the Partnership that the unitholder owns. In addition, pursuant to a purchase agreement between LB Pacific and PAA, PAA will acquire from LB Pacific the general partner interest and incentive distribution rights of the Partnership, as well as 5,232,500 common units and 5,232,500 subordinated units, for total consideration of $700 million in cash. The merger agreement was unanimously approved by the Board of Directors of PEM, as well as by the board of directors of PAA s general partner.

Each of the Partnership and PAA made customary representations, warranties and covenants in the merger agreement, which are described in the joint proxy statement/prospectus filed by the Partnership and PAA with the Securities and Exchange Commission (the SEC). The merger is subject to the satisfaction or waiver of certain conditions, including the receipt of various regulatory approvals or the expiration of various regulatory waiting periods, all of which approvals or waiting periods have been obtained, and the adoption and approval of the merger agreement and the merger by the holders of at least a majority of the Partnership s outstanding common units (excluding common units held by LB Pacific) and outstanding subordinated units, each voting as a separate class. The merger agreement and the merger must also be adopted and approved by the holders of at least a majority of PAA s outstanding common units.

The Partnership s and PAA s special meetings of unitholders to consider the merger agreement and the merger are scheduled to occur on November 9, 2006. Although the Partnership and PAA cannot be sure when all of the conditions to the merger will be satisfied, the parties expect to complete the merger on November 15, 2006 (assuming the proposals are approved by the unitholders and all other conditions to closing are satisfied).

During the three and nine months ended September 30, 2006, the Partnership incurred approximately $1.1 million and $4.5 million, respectively, in costs directly relating to the merger for investment banking fees, legal fees and other transaction costs. Approximately $0.7 million of investment banking fees were paid to affiliates of Lehman Brothers Inc., an affiliate of the General Partner (see Note 5 Related Party Transactions). These costs are included in the condensed consolidated statements of income under the caption Merger costs .

3. INCOME TAXES

The Partnership and its U.S. and Canadian subsidiaries are not taxable entities in the U.S. and are not subject to U.S. federal or state income taxes, as the tax effect of operations is passed through to its unitholders. However, the Partnership s Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, inter-company interest payments and repatriation of funds through dividend payments are subject to withholding tax.

Income taxes for the Partnership s Canadian subsidiaries are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in operations in the period that includes the enactment date. The Partnership intends to repatriate its Canadian subsidiaries earnings in the future and accordingly has recorded a provision for Canadian withholding taxes.

In the second quarter of 2006, the Canadian and Alberta governments enacted legislation which will reduce federal and provincial income taxes. The Partnership adjusted the future income tax rates used in the estimates of deferred tax assets and liabilities and recognized a $4.6 million deferred tax benefit in the quarter ended June 30, 2006.

4. NET INCOME PER LIMITED PARTNER UNIT

Net income is allocated to the Partnership s General Partner and limited partners based on their respective interests in the Partnership. The Partnership s General Partner is also directly charged with specific costs that it has individually assumed and for which the limited partners are not responsible.

Basic net income per limited partner unit is determined by dividing net income, after adding back costs and deducting certain amounts allocated to the General Partner (including incentive distribution payments in excess of its 2% ownership interest), by the weighted average number of outstanding limited partner units.

Diluted net income per limited partner unit is calculated in the same manner as basic net income per limited partner unit above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options, if any, and restricted units by application of the treasury stock method.

Set forth below is the computation of net income allocated to limited partners and net income per basic and diluted limited partner unit. The table also shows the reconciliation of basic average limited partner units to diluted weighted average limited partner units.

	Three Months Ended September 30,		Nine Months Ended September30,	
	2006	2005	2006	2005
	(in thousands)			
Numerator:				
Net income allocated to limited partners:				
Net income	$ 19,235	$ 12,166	$ 52,292	$ 27,807
Costs allocated to the general partner(1):				
LB Pacific Option Plan expense	370		1,250	
Senior Notes consent solicitation and other costs				893
Severance and other costs				914
Total costs allocated to the general partner	370		1,250	1,807
Income before costs allocated to the general partner	19,605	12,166	53,542	29,614
Less: general partner incentive distributions	(331)		(917)	
	19,274	12,166	52,625	29,614
Less: General partner 2% ownership	(386)	(243)	(1,053)	(592)
Net income for the limited partners	$ 18,888	$ 11,923	$ 51,572	$ 29,022
Denominator:				
Basic weighted average limited partner units	39,307	30,761	39,305	30,051
Effect of restricted units	14		27	25
Effect of options		1		13
Diluted weighted average limited partner units	39,321	30,762	39,332	30,089
Basic net income per limited partner unit	$ 0.48	$ 0.39	$ 1.31	$ 0.97
Diluted net income per limited partner unit	$ 0.48	$ 0.39	$ 1.31	$ 0.96

(1) See Note 5 Related Party Transactions for a description of transaction costs reimbursed by the General Partner.

5. RELATED PARTY TRANSACTIONS

Cost Reimbursements

Managing General Partner: The Partnership s General Partner employs all U.S.-based employees. All employee expenses incurred by the General Partner on behalf of the Partnership are charged back to the Partnership.

LB Pacific, LP Option Plan: LB Pacific, LP (LB Pacific), the owner of the Partnership s General Partner, has adopted an option plan for certain officers, directors, employees, advisors, and consultants of PEM, LB Pacific, and their affiliates. Under the plan, participants may be granted options to acquire partnership interests in LB Pacific. The Partnership is not obligated to pay any amounts to LB Pacific for the benefits granted or paid to any participants under the plan, although generally accepted accounting principles require that the Partnership record an expense in its financial statements for benefits granted to employees of PEM or the Partnership who provide services to the Partnership, with a corresponding increase in the General Partner s capital account.

The option plan is administered by the board of directors of LB Pacific GP, LLC, the general partner of LB Pacific. The terms, conditions, performance goals, restrictions, limitations, forfeiture, vesting or exercise schedule, and other provisions of grants under the plan, as well as eligibility to participate, are determined by the board of directors of LB Pacific GP, LLC. The board of directors of LB Pacific GP, LLC may determine to grant options under the plan to participants containing such terms as the board of LB Pacific GP, LLC shall determine. Options will have an exercise price that may not be less than the fair market value of the units on the date of grant.

Information concerning the plan and grants is shared by LB Pacific, LP with the General Partner s Compensation Committee and Board of Directors, and considered in determining the long term incentive compensation paid by the Partnership to participants in the plan.

In January 2006, LB Pacific granted options representing a maximum 24% interest in LB Pacific (assuming all options vest and are exercised), which options vest over a period of 10 years from the date of grant (except in limited circumstances such as a change in control), to certain officers and key employees of PEM and the Partnership. The grants, qualified as equity-classified awards, had a grant date fair value of $8.6 million. The fair value of the options was determined using valuation techniques that included the discounted present value of estimated future cash flows for LB Pacific and fundamental analysis. It was measured using the Black-Scholes option pricing model with the following assumptions:

Expected volatility	21.86	%
Expected dividend yield	0	%
Expected term (in years)	10	
Risk-free rate	4.37	%

For the three and nine months ended September 30, 2006, the Partnership recognized $0.4 million and $1.3 million in compensation expense relating to the LB Pacific options and recorded a capital contribution from the General Partner for the same amounts. At September 30, 2006, all granted LB Pacific options remained outstanding. At September 30, 2006, there was $7.3 million of total unrecognized compensation cost related to nonvested options granted under the plan, which cost was expected to be recognized over the remaining period of 9.25 years. Upon the close of the proposed merger with PAA, the options will become immediately exercisable. Total unrecognized compensation expense on the closing date will be immediately recognized in the income statement.

LB Pacific, LP and Anschutz: Prior to March 3, 2005, the General Partner was owned by The Anschutz Corporation (Anschutz). On March 3, 2005, Anschutz sold its interest in the Partnership, including its interest in the General Partner, to LB Pacific. In connection with the sale of Anschutz s interest in the Partnership to LB Pacific, LB Pacific and Anschutz reimbursed the Partnership for certain costs incurred in connection with the acquisition. The Partnership was reimbursed $1.2 million for costs incurred in connection with the consent solicitation, $0.3 million of legal and other costs, and $0.9 million relating to severance costs, for a total of $2.4 million. Of the $2.4 million total incurred, $1.8 million was expensed, as shown on the income statement as reimbursed general partner transaction costs, and $0.6 million of the consent solicitation costs were capitalized as deferred financing costs.

Special Agreement: On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors, entered into a Special Agreement and a Consulting Agreement with PEM. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors effective March 3, 2005. Mr. Polson was paid approximately $0.9 million, representing accrued salary through March 3, 2005, accrued but unused vacation, and payment in satisfaction of other obligations under his employment agreement. The latter portion of this payment was recorded as an expense in Reimbursed general partner transaction costs in the accompanying condensed consolidated income statements. LB Pacific reimbursed this amount, which was recorded as a partner s capital contribution. Pursuant to the Consulting

Agreement, Mr. Polson agreed to perform advisory services to PEM from time to time as mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson s services under the Consulting Agreement, which had a one-year term, Mr. Polson received a monthly consulting fee of $12,500 and reimbursement of all reasonable business expenses incurred or paid by Mr. Polson in the course of performing his duties thereunder.

Lehman Brothers, Inc.

Lehman Brothers, Inc. is deemed to be an affiliate of the Partnership s General Partner through a 59% ownership interest in LB Pacific, which is controlled by Lehman Brothers Holdings Inc., the parent entity of Lehman Brothers, Inc. Lehman Brothers, Inc. acted as financial advisor to LB Pacific and the Partnership in connection with the proposed merger and the transactions related to the merger (see Note 2 Proposed Merger With Plains All American, L.P.). As part of its services, Lehman Brothers, Inc. delivered an opinion to the Board of Directors to the effect that, as of the date of its opinion and based on and subject to various assumptions made, the aggregate consideration to be offered to all of the holders of the partnership interests in the Partnership in the proposed merger transaction is fair to such holders. The agreement with Lehman Brothers, Inc. was reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the type of services provided. The Partnership incurred $0.7 million in fees with Lehman Brothers, Inc. for the nine months ended September 30, 2006, none of which was incurred in the three months ended September 30, 2006. The Partnership has agreed to pay Lehman Brothers, Inc. an additional $7.7 million success fee contingent on the successful consummation of the merger.

In connection with the purchase and the associated financing of the Partnership s purchase of certain terminal and pipeline assets from Valero, L.P. in September 2005, including a private equity offering, public equity offering, debt offering and new credit facility, Lehman Brothers, Inc. and its affiliates provided advisory and underwriting services to the Partnership. Additionally, an affiliate of Lehman Brothers, Inc. is a participant in the syndicate that provided the Partnership s new senior secured credit facility. These agreements with Lehman Brothers, Inc. were reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the types of services provided. For the three and nine months ended September 30, 2005, the Partnership incurred $9.8 million in fees with Lehman Brothers, Inc. and its affiliates, a portion of which was paid to non-affiliated financial institutions in the syndication of the new credit facility and in the public offering of equity.

Other Related Party Transactions

RMPS receives an operating fee and management fee from Frontier Pipeline Company (Frontier) in connection with time spent by RMPS management and for other services related to Frontier s activities. RMPS received $0.2 million for each of the three months ended September 30, 2006 and 2005 and $0.6 million for each of the nine months ended September 30, 2006 and 2005, respectively. The Partnership owns a 22.22% partnership interest in Frontier.

6. CONTINGENCIES

Line 63 Oil Release

In March 2005, a release of approximately 3,400 barrels of crude oil occurred on the Partnership s Line 63 when it was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through anticipated completion in June 2007, the Partnership expects to incur an estimated total of $25.5 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of September 30, 2006, the Partnership had incurred approximately 22.3 illion of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that the $3.2 million of remaining remediation cost will substantially be incurred before June 2007.

In March 2006, Pacific Pipeline System LLC (PPS), a subsidiary of the Partnership, was served with a four count misdemeanor action by the state of California, which alleges that PPS violated various state statutes by depositing oil or substances harmful to wildlife into the environment and by the willful and intentional discharge of pollution into state waters. The Partnership estimates that the maximum fine and penalties that could be assessed for these actions is approximately $0.9 million in the aggregate. The Partnership believes, however, that certain of the alleged violations are without merit and intends to defend against them, and that mitigating factors should otherwise reduce the amounts of any potential fines or penalties that might be assessed. At this time, the Partnership cannot reasonably determine the outcome of these allegations. The estimated range of possible fines or penalties including amounts not covered by insurance is between $0 and $0.9 million.

The Partnership has a pollution liability insurance policy with a $2.0 million per-occurrence deductible that covers containment and clean-up costs, third-party claims and certain penalties. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. The Partnership believes that, subject to the $2.0 million deductible, it will be entitled to recover substantially all of its clean-up costs and any third-party claims associated with the release. As of September 30, 2006, the Partnership has recovered $18.6 million from insurance and recorded net receivables of $4.6 million for future insurance recoveries it deems probable.

The foregoing estimates are based on facts known at the time of estimation and the Partnership s assessment of the ultimate outcome. Among the many uncertainties that impact the estimates are the necessary regulatory approvals for, and potential modification of, remediation plans, the ongoing assessment of the impact of soil and water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that costs incurred in excess of this provision, if any, would not have a material adverse effect on the Partnership s financial condition, results of operations, or cash flows, though the Partnership believes that most, if not all, of any such excess cost, to the extent attributable to clean-up and third-party claims, would be recoverable through insurance. In March 2006, A.M. Best Company, an insurance company rating agency, announced it had downgraded the financial strength rating assigned to the Partnership s insurance carrier, Quanta Specialty Lines Company, including its parent and affiliates. The downgrade was from an A to a B++, under review with negative implications. During the second quarter of 2006, Quanta announced that their Board of Directors decided to cease underwriting or seeking new business and to place most of its remaining specialty insurance and reinsurance lines into orderly run-off. On June 7, 2006 A. M. Best further downgraded Quanta from B++ to B. Subsequent to this downgrading, Quanta was removed from A. M. Best s interactive rating process, at Quanta s request. Based on management s further analysis of Quanta s financial condition, the Partnership believes that Quanta will continue to meet its obligations relating to the Line 63 oil release, although there can be no assurance that this will be the case. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

Product Contamination

In June 2006, approximately 44,000 barrels of a customer s product at our Martinez terminal was contaminated. The Partnership has insurance coverage for the damage or loss of its customers products while in its care, custody and control at certain of its terminals subject to a $0.1 million per-occurrence deductible. The Partnership recognized a loss of $0.2 million to cover the insurance deductible and other associated costs. At this time, the Partnership believes costs related to the contamination of the property will be covered under the insurance policy, and has accrued an estimated $1.1 million in total costs, which is included in Other current liabilities in the accompanying condensed consolidated balance sheet. The Partnership has recorded a receivable of $0.9 million for future insurance recoveries it deems probable.

Litigation

On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, entitled *Kosseff v. Pacific Energy, et al,* case no. BC 3544016. The plaintiff alleged that he was a unitholder of the Partnership and he sought to represent a class comprising all of the Partnership s unitholders. The complaint named as defendants the Partnership and certain of the officers and directors of the Partnership s general partner, and asserted claims of self-dealing and breach of fiduciary duty in connection with the pending merger with PAA and related transactions. The plaintiff sought injunctive relief against completing the merger or, if the merger was completed, rescission of the merger, other equitable relief, and recovery of the plaintiff s costs and attorneys fees. On September 14, 2006, the Partnership and the other defendants entered into a memorandum of settlement with the plaintiff to settle the lawsuit. As part of the settlement, the Partnership and the other defendants deny all allegations of wrongdoing and maintain that they are willing to settle the lawsuit solely because the settlement would eliminate the burden and expense of further litigation. The settlement is subject to customary conditions, including court approval. As part of the settlement, the Partnership will, subject to the consummation of the merger, pay $475,000 to the plaintiff s counsel for their fees and expenses, and incur approximately $0.1 to $0.2 million for costs of mailing materials to unitholders. If finally approved by the court, the settlement will resolve all claims that were or could have been brought on behalf of the proposed settlement class in the actions being settled, including all claims relating to the merger, the merger agreement and any disclosure made by the Partnership in connection with the merger. The settlement will not change any of the terms or conditions of the merger. The Partnership will record the settlement amount and associated costs upon completion of the merger.

In August, 2005, Rangeland Pipeline Company (RPC), a wholly-owned subsidiary of the Partnership, learned that a Statement of Claim was filed by Desiree Meier and Robert Meier in the Alberta Court of Queen s Bench, Judicial District of Red Deer, naming RPC as defendant, and alleging personal injury and property damage caused by an alleged release of petroleum substances onto plaintiff s land by a prior owner and operator of the pipeline that is currently owned and operated by the Partnership. The claim seeks Cdn$1 million (approximately U.S.$0.9 million at September 30, 2006) in general damages, Cdn$2 million (approximately U.S.$1.8 million at September 30, 2006) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. RPC believes the claim is without merit, and intends to vigorously defend against it. RPC also believes that certain of the claims, if successfully proven by the plaintiffs, would be liabilities retained by the pipeline s prior owner under the terms of the agreement whereby the Partnership acquired the pipeline in question.

In connection with the acquisition of assets from Valero, L.P. in September 2005, the Partnership assumed responsibility for the defense of a lawsuit filed in 2003 against Support Terminals Services, Inc. (ST Services) by ExxonMobil Corporation (ExxonMobil) in New Jersey state court. The Partnership has also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks reimbursement of approximately $400,000 for remediation costs it has incurred, from GATX Corporation, Kinder Morgan Liquid Terminals, the successor in interest to GATX Terminals Corporation, and ST Services. ExxonMobil also seeks a ruling imposing liability for any future remediation and related liabilities on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by the Partnership on September 30, 2005. ExxonMobil claims that the costs and future remediation requirements are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that, therefore, any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan and ST Services. The Partnership believes the claims against ST Services are without merit, and intends to vigorously defend against them.

In 2001, Big West Oil Company and Chevron Products Company (the Complainants) filed complaints against Frontier Pipeline Company (Frontier) with the Federal Energy Regulatory Commission (FERC) challenging rates contained in joint tariffs in which Frontier was a participating carrier and rates contained in local tariffs filed by Frontier. On February 18, 2004, the FERC found against Frontier on certain of the Complainants claims and ordered Frontier to pay reparations to Complainants in the aggregate amount of approximately $4.2 million, plus interest, which Frontier paid in August 2004. On October 5, 2004, Frontier filed a petition for review of the FERC s reparations orders in the U.S. Court of Appeals for the D.C. Circuit, and on May 26, 2006 the Court of Appeals held that the FERC s reparation ruling was inconsistent with applicable law, and thus vacated the FERC s order and remanded the matter back to the FERC for further consideration consistent with the Court of Appeals decision. On July 25, 2006, Frontier filed a motion asking the FERC to dismiss the reparations complaints of the Complainants on the grounds that their complaints fail to state claims that can be sustained consistent with the ruling of the Court of Appeals. Frontier s motion also asked the FERC to order the refund by the Complainants of the reparations previously paid by Frontier, plus interest. The Complainants have, in a response to Frontier s motion, asserted for various reasons that the FERC should essentially reinstate its original ruling that ordered Frontier to pay reparations to the Complainants. No action on the motions has been taken by the FERC. If Frontier prevails on its motion or in any remand proceeding conducted by the FERC, it would be entitled to repayment in the amount of $5.4 million, plus interest thereon from August 23, 2004. The Partnership owns 22.22% of Frontier. Although the Partnership believes Frontier s motion to dismiss the complaints, as well as the defenses it would assert in a remand proceeding before the FERC, are meritorious, the Partnership cannot predict the outcome of any such actions, and has not recorded any amount for this contingency.

The Partnership is involved in various other regulatory disputes, litigation and claims arising out of its operations in the normal course of business. The Partnership is not currently a party to any legal or regulatory proceedings the resolution of which could be expected to have a material adverse effect on its business, financial condition, liquidity or results of operations.

7. RESTRICTED UNITS

A restricted unit is a phantom unit under the Partnership s long term incentive compensation plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit**.** The Partnership intends the issuance of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for such units.

In January 2006 and May 2006, the General Partner awarded 89,110 restricted units to key employees and outside directors that vest over a three-year period, beginning on March 1, 2006 and March 1, 2007, respectively. The number of units to be delivered to key employees in any year, if any, will be based on accomplishment of performance targets (measured by distributable cash flow) for the previous calendar year, subject to the Compensation Committee s authority to subsequently adjust performance targets as it may deem appropriate, in its discretion. Restricted unit activity during the nine months ended September 30, 2006 is as follows:

	Number of Units	Weighted Average Grant Date Fair Value (in thousands)
Outstanding at January 1, 2006		$
Changes during the year:		
Granted	89,110	2,759
Vested	(10,439)	(314)
Forfeited	(5,430)	(164)
Outstanding at September 30, 2006	73,241	$ 2,281

Compensation expense recognized for outstanding restricted units is based on grant date fair value of the common units to be awarded to the grantee upon vesting of the phantom unit, adjusted for the expected target performance level for each year. For the three and nine months ended September 30, 2006, the Partnership incurred $0.2 million and $0.8 million, respectively, in compensation expense for restricted units it deemed probable of achieving the performance criteria, including the amount for the first vesting of these awards which occurred on March 1, 2006.

The outstanding unit grants include change of control provisions that require immediate vesting of units in the event of a change in control of the Partnership or its General Partner. Upon the close of the proposed merger with PAA, all outstanding restricted units will immediately vest pursuant to the terms of the grants, and any remaining unamortized compensation expense will be immediately recognized.

On March 3, 2005, in connection with LB Pacific s acquisition of the Partnership s General Partner, all restricted units then outstanding under the Partnership s Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. The Partnership issued 99,583 common units and recognized a compensation expense of $3.1 million, which is included in Accelerated long-term incentive plan compensation expense in the accompanying condensed consolidated statements of income. Of the total $3.1 million, the compensation expense categorization was $0.6 million for operating personnel and $2.5 million for general and administrative personnel.

8. SEGMENT INFORMATION

The Partnership s business and operations are organized into two business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. The West Coast Business Unit includes: (i) Pacific Pipeline System LLC, owner of Line 2000 and Line 63, (ii) Pacific Marketing and Transportation LLC (West Coast Business Unit operations), owner of the PMT gathering system and marketer of crude oil, (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system, and (iv) Pacific Atlantic Terminals LLC, owner of the San Francisco and Philadelphia area terminals, which were acquired on September 30, 2005. The Rocky Mountain Business Unit includes: (i) Rocky Mountain Pipeline System LLC, owner of the Partnership s interest in various pipelines that make up the Western Corridor and Salt Lake City Core systems, and the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005, (ii) Ranch Pipeline LLC, the owner of a 22.22% partnership interest in Frontier Pipeline Company, (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate the Rangeland system, and

(iv) Pacific Marketing and Transportation LLC (Rocky Mountain Business Unit operations), a marketer of crude oil.

General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and business development, are not allocated to the individual business units. Information regarding these two business units is summarized below:

	West Coast Business Unit (in thousands)	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
Three months ended September 30, 2006				
Revenues:				
Pipeline transportation revenue	$ 18,224	$ 21,500	$ (2,729)	$ 36,995
Storage and terminaling revenue	23,467			23,467
Pipeline buy/sell transportation revenue(1)		10,010		10,010
Crude oil sales, net of purchases(2)	9,494	572	(142)	9,924
Net revenue	51,185	32,082		80,396
Expenses:				
Operating	21,505	15,412	(2,871)	34,046
Depreciation and amortization	5,528	4,870		10,398
Total expenses	27,033	20,282		44,444
Share of net income of Frontier		373		373
Operating income from segments(3)	$ 24,152	$ 12,173		$ 36,325
Total business unit assets(4)	$ 915,707	$ 643,935		$ 1,559,642
Capital expenditures(5)	$ 8,008	$ 12,628		$ 20,636
Three months ended September 30, 2005				
Revenues:				
Pipeline transportation revenue	$ 13,887	$ 14,887	$ (1,491)	$ 27,283
Storage and terminaling revenue	9,731			9,731
Pipeline buy/sell transportation revenue(1)		11,683		11,683
Crude oil sales, net of purchases(2)	5,690	163	(30)	5,823
Net revenue	29,308	26,733		54,520
Expenses:				
Operating	16,004	10,536	(1,521)	25,019
Depreciation and amortization	3,491	3,069		6,560
Total expenses	19,495	13,605		31,579
Share of net income of Frontier		516		516
Operating income from segments(3)	$ 9,813	$ 13,644		$ 23,457
Total business unit assets(4)	$ 855,191	$ 551,279		$ 1,406,470
Capital expenditures(5)	$ 5,106	$ 9,403		$ 14,509

	West Coast Business Unit (in thousands)	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
Nine months ended September 30, 2006				
Revenues:				
Pipeline transportation revenue	$ 52,083	$ 60,790	$ (7,221)	$ 105,652
Storage and terminaling revenue	65,420			65,420
Pipeline buy/sell transportation revenue(1)		31,136		31,136
Crude oil sales, net of purchases(2)	26,000	1,860	(407)	27,453
Net revenue	143,503	93,786		229,661
Expenses:				
Operating	63,200	43,548	(7,628)	99,120
Depreciation and amortization	16,534	14,158		30,692
Total expenses	79,734	57,706		129,812
Share of net income of Frontier		1,246		1,246
Operating income from segments(3)	$ 63,769	$ 37,326		101,095
Total business unit assets(4)	$ 915,707	$ 643,935		$ 1,559,642
Capital expenditures(5)	$ 29,635	$ 24,313		$ 53,948
Nine months ended September 30, 2005				
Revenues:				
Pipeline transportation revenue	$ 46,525	$ 41,348	$ (4,806)	$ 83,067
Storage and terminaling revenue	31,073		(150)	30,923
Pipeline buy/sell transportation revenue(1)		28,905		28,905
Crude oil sales, net of purchases(2)	13,368	369	(90)	13,647
Net revenue	90,966	70,622		156,542
Expenses:				
Operating	46,507	30,604	(5,046)	72,065
Line 63 oil release costs(6)	2,000			2,000
Depreciation and amortization	10,497	9,198		19,695
Total expenses	59,004	39,802		93,760
Share of net income of Frontier		1,363		1,363
Operating income from segments(3)	$ 31,962	$ 32,183		$ 64,145
Total business unit assets(4)	$ 855,191	$ 551,279		$ 1,406,470
Capital expenditures(5)	$ 6,790	$ 14,870		$ 21,660

(1) Pipeline buy/sell transportation revenue reflects net revenues of approximately $3.4 million and $2.5 million on buy/sell transactions with different parties of $95.6 million and $77.5 million for the three months ended September 30, 2006 and 2005, respectively and net revenues of approximately $10.2 million and $4.6 million on buy/sell transactions with different parties of $257.2 million and $126.0 million for the nine months ended September 30, 2006 and 2005, respectively. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of $421.3 million and $188.9 million for the three months ended September 30, 2006 and 2005 and $1,031.2 million and $425.7 million for the nine months ended September 30, 2006 and 2005, respectively.

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(3) The following is a reconciliation of operating income as stated above to net income:

	Three Months Ended September 30, 2006 (in thousands)	2005	Nine Months Ended September 30, 2006	2005
Income Statement Reconciliation				
Operating income from above:				
West Coast Business Unit	$ 24,152	$ 9,813	$ 63,769	$ 31,962
Rocky Mountain Business Unit	12,173	13,644	37,326	32,183
Operating income from segments	36,325	23,457	101,095	64,145
Less: General and administrative expense	5,649	4,115	18,236	12,987
Less: Merger costs	1,112		4,529	
Less: Accelerated long-term incentive plan compensation expense				3,115
Less: Reimbursed general partner transaction costs				1,807
Operating income	29,564	19,342	78,330	46,236
Interest expense	(10,853)	(6,237)	(30,029)	(17,679)
Other income	720	494	1,455	1,387
Income tax benefit (expense)	(196)	(1,433)	2,536	(2,137)
Net income	$ 19,235	$ 12,166	$ 52,292	$ 27,807

(4) Business unit assets do not include assets related to the Partnership s parent level activities. As of September 30, 2006 and 2005, parent level related assets were $52.6 million and $50.8 million, respectively.

(5) Segment capital expenditures do not include parent level capital expenditures. Parent level capital expenditures were $4.4 million and $2.9 million for the three months ended September 30, 2006 and 2005 and $13.6 million and $5.6 million for the nine months ended September 30, 2006 and 2005, respectively.

(6) On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS s Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, the Partnership recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of what it now estimates to be $25.5 million of accrued costs relating to the release, net of insurance recovery of $18.6 million to September 30, 2006 and accrued insurance receipts of $4.6 million.

9. SUBSEQUENT EVENTS

On October 20, 2006, the Partnership declared a cash distribution of $0.5675 per limited partner unit, payable on November 13, 2006, to unitholders of record as of October 31, 2006.

10. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Certain of the Partnership s 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of the 7⁄8% senior notes due 2014 and the 6⁄4% senior notes due 2015 (the Senior Notes). Given that certain, but not all subsidiaries of the Partnership are guarantors of its Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, the Partnership is referred to as Parent , while the Guarantor Subsidiaries are Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Ranch Pipeline LLC, PEG Canada GP LLC,

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PEG Canada, L.P. and Pacific Energy Group LLC, and Non-Guarantor Subsidiaries are Pacific Pipeline System LLC, Pacific Terminals LLC, Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership and Aurora Pipeline Company, Ltd.

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

Balance Sheet
September 30, 2006

	Parent (in thousands)	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
Assets:					
Current assets	$ 102,469	$ 214,172	$ 90,023	$ (141,438)	$ 265,226
Property and equipment		628,308	624,442		1,252,750
Equity investments	514,163	213,942		(719,454)	8,651
Intercompany notes receivable	658,364	343,831		(1,002,195)	
Intangible assets		28,982	38,657		67,639
Other assets	11,624		6,333		17,957
Total assets	$ 1,286,620	$ 1,429,235	$ 759,455	$ (1,863,087)	$ 1,612,223
Liabilities and partners capital:					
Current liabilities	$ 8,061	$ 247,636	$ 89,901	$ (141,438)	$ 204,160
Long-term debt	589,529		79,634		669,163
Deferred income taxes		1,233	31,327		32,560
Intercompany notes payable		658,364	343,831	(1,002,195)	
Other liabilities	106	7,839	9,471		17,416
Total partners capital	688,924	514,163	205,291	(719,454)	688,924
Total liabilities and partners capital	$ 1,286,620	$ 1,429,235	$ 759,455	$ (1,863,087)	$ 1,612,223

Balance Sheet
December 31, 2005

	Parent (in thousands)	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
Assets:					
Current assets	$ 104,989	$ 139,457	$ 81,846	$ (134,177)	$ 192,115
Property and equipment		583,330	602,204		1,185,534
Equity investments	429,802	197,239		(618,885)	8,156
Intercompany notes receivable	661,313	340,905		(1,002,218)	
Intangible assets		31,220	37,960		69,180
Other assets	13,426		8,041		21,467
Total assets	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452
Liabilities and partners capital:					
Current liabilities	$ 5,389	$ 191,516	$ 93,459	$ (134,177)	$ 156,187
Long-term debt	505,902		59,730		565,632
Deferred income taxes		582	35,189		35,771
Intercompany notes payable		661,313	340,905	(1,002,218)	
Other liabilities		8,938	11,685		20,623
Total partners capital	698,239	429,802	189,083	(618,885)	698,239
Total liabilities and partners capital	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452

Statement of Income
Three Months Ended September 30, 2006

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 42,362	$ 40,905	$ (2,871)	$ 80,396
Operating expenses		(20,625)	(16,292)	2,871	(34,046)
General and administrative expense(1)	(2)	(5,050)	(597)		(5,649)
Merger costs		(1,112)			(1,112)
Depreciation and amortization expense		(5,138)	(5,260)		(10,398)
Share of net income of Frontier		373			373
Operating income	(2)	10,810	18,756		29,564
Interest expense	(9,532)	(40)	(1,281)		(10,853)
Intercompany interest income (expense)		7,391	(7,391)		
Equity earnings	28,856	10,578		(39,434)	
Other income	(87)	396	411		720
Income tax (expense) benefit		(279)	83		(196)
Net income	$ 19,235	$ 28,856	$ 10,578	$ (39,434)	$ 19,235

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

Statement of Income
Three Months Ended September 30, 2005

	Parent (in thousands)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
Net operating revenues	$	$ 20,740	$ 35,301	$ (1,521)	$ 54,520
Operating expenses		(11,171)	(15,369)	1,521	(25,019)
General and administrative expense(1)		(3,594)	(521)		(4,115)
Depreciation and amortization expense		(1,633)	(4,927)		(6,560)
Share of net income of Frontier		516			516
Operating income		4,858	14,484		19,342
Interest expense	(4,630)	(818)	(789)		(6,237)
Intercompany interest income (expense)		6,639	(6,639)		
Equity earnings	16,585	6,115		(22,700)	
Other income	211	180	103		494
Income tax (expense) benefit		(398)	(1,035)		(1,433)
Net income	$ 12,166	$ 16,576	$ 6,124	$ (22,700)	$ 12,166

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(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

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Statement of Income
Nine Months Ended September 30, 2006

	Parent (in thousands)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Net operating revenues	$	$ 118,892	$ 118,397	$ (7,628)	$ 229,661
Operating expenses		(59,507)	(47,241)	7,628	(99,120)
General and administrative expense(1)	(3)	(16,423)	(1,810)		(18,236)
Merger costs		(4,529)			(4,529)
Depreciation and amortization expense		(15,207)	(15,485)		(30,692)
Share of net income of Frontier		1,246			1,246
Operating income	(3)	24,472	53,861		78,330
Interest expense	(26,534)	(181)	(3,314)		(30,029)
Intercompany interest income (expense)		21,912	(21,912)		
Equity earnings	79,218	33,519		(112,737)	
Other income	(389)	987	857		1,455
Income tax benefit (expense)		(1,491)	4,027		2,536
Net income	$ 52,292	$ 79,218	$ 33,519	$ (112,737)	$ 52,292

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

Statement of Income
Nine Months Ended September 30, 2005

	Parent (in thousands)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
Net operating revenues	$	$ 55,085	$ 106,503	$ (5,046)	$ 156,542
Operating expenses		(31,461)	(45,650)	5,046	(72,065)
General and administrative expense(1)		(11,420)	(1,567)		(12,987)
Accelerated long-term incentive plan compensation expense		(2,675)	(440)		(3,115)
Line 63 oil release costs			(2,000)		(2,000)
Reimbursed general partner transaction costs	(893)	(914)			(1,807)
Depreciation and amortization expense		(4,893)	(14,802)		(19,695)
Share of net income of Frontier		1,363			1,363
Operating income	(893)	5,085	42,044		46,236
Interest expense	(12,925)	(2,322)	(2,432)		(17,679)
Intercompany interest income (expense)		19,051	(19,051)		
Equity earnings	41,397	19,691		(61,088)	
Other income	228	780	379		1,387
Income tax benefit (expense)		(888)	(1,249)		(2,137)
Net income	$ 27,807	$ 41,397	$ 19,691	$ (61,088)	$ 27,807

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

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Statement of Cash Flows
Nine Months Ended September 30, 2006

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 52,292	$ 79,218	$ 33,519	$ (112,737)	$ 52,292
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(79,218)	(33,519)		112,737	
Distributions from subsidiaries	68,714	46,418		(115,132)	
Depreciation, amortization and other	2,941	16,025	8,492		27,458
Net changes in operating assets and liabilities	2,267	(30,645)	(1,081)	(800)	(30,259)
NET CASH PROVIDED BY OPERATING ACTIVITIES	46,996	77,497	40,930	(115,932)	49,491
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions		(2,365)			(2,365)
Additions to property, equipment and other	(24)	(48,371)	(18,946)		(67,341)
Additions to pipeline linefill and minimum tank inventory		(8,128)	(7,978)		(16,106)
Intercompany	(84,000)			84,000	
NET CASH USED IN INVESTING ACTIVITIES	(84,024)	(58,864)	(26,924)	84,000	(85,812)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	35,458	(23,136)	(12,365)	31,932	31,889
Effect of translation adjustment			83		83
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,570)	(4,503)	1,724		(4,349)
CASH AND CASH EQUIVALENTS, beginning of reporting period	4,192	12,484	1,388		18,064
CASH AND CASH EQUIVALENTS, end of reporting period	$ 2,622	$ 7,981	$ 3,112	$	$ 13,715

Statement of Cash Flows
Nine Months Ended September 30, 2005

	Parent (in thousands)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 27,807	$ 41,397	$ 19,691	$ (61,088)	$ 27,807
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(41,397)	(19,691)		61,088	
Distributions from subsidiaries	46,224	31,888		(78,112)	
Depreciation, amortization and other	514	8,645	15,097		24,256
Net changes in operating assets and liabilities	8,877	9,601	1,948	(6,834)	13,592
NET CASH PROVIDED BY OPERATING ACTIVITIES	42,025	71,840	36,736	(84,946)	65,655
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions		(461,165)			(461,165)
Additions to property, equipment and other		(10,916)	(16,349)		(27,265)
Intercompany	(465,633)			465,633	
NET CASH USED IN INVESTING ACTIVITIES	(465,633)	(472,081)	(16,349)	465,633	(488,430)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	427,090	395,844	(17,293)	(380,687)	424,954
Effect of translation adjustment			213		213
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3,482	(4,397)	3,307		2,392
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713	17,523	3,147		23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 6,195	$ 13,126	$ 6,454	$	$ 25,775

ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

References in this quarterly report on Form 10-Q to Pacific Energy Partners, Partnership, we, ours, us or like terms refer to Pacific Energy Partners, L.P. and its subsidiaries.

Forward-Looking Statements

The information in this quarterly report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified as any statements that do not relate strictly to historical or current facts, including statements that use terms such as anticipate, assume, believe, estimate, expect, fore intend, plan, position, predict, project, or strategy or the negative connotation or other variations of such terms or other similar terminolog particular, statements express or implied, regarding our future results of operations or our ability to generate sales, income or cash flow or to make distributions to unitholders are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are based on management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve risks and uncertainties. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil and other related products and buying, gathering, blending and selling crude oil or related to our pending merger with Plains All American Pipeline, L.P. For a more detailed description of these and other factors that may affect the forward-looking statements, please read Item 1A Risk Factors contained elsewhere in this report and in our annual report on Form 10-K and Form 10-K/A for the year ended December 31, 2005, Plains All American Pipeline, L.P. joint proxy statement/prospectus on Form S-4, which was declared effective by the Securities and Exchange Commission (SEC) on September 29, 2006, as well as our other filings with the SEC. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward-looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P. should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to our unaudited condensed consolidated balance sheets, statements of income, statements of cash flows and statement of partners capital.

This report on Form 10-Q should be read in conjunction with our annual report on Form 10-K and Form 10-K/A for the year ended December 31, 2005.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing, and distributing crude oil, refined products and other related products. We generate revenue primarily by transporting such commodities on our pipelines, by leasing capacity in our storage tanks, and by providing other terminaling services. We also buy and sell crude oil, activities that are generally complementary to our other crude oil operations. We conduct our business through two business units, the

West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

We are managed by our general partner, Pacific Energy GP, LP, which is in turn managed by its general partner, Pacific Energy Management LLC (PEM). Thus, the officers and Board of Directors of PEM manage the business affairs of Pacific Energy GP, LP and the Partnership. References to our General Partner refer to Pacific Energy GP, LP and/or PEM, as the context indicates.

Our West Coast Business Unit consists of (i) the Line 2000 crude oil pipeline, (ii) the Line 63 crude oil pipeline system, (iii) the Pacific Terminals storage and distribution system, (v) the Pacific Marketing and Transportation (PMT) gathering system and crude oil marketing activities, and (iv) the Pacific Atlantic terminals, which we acquired on September 30, 2005. Line 2000 and Line 63 are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley, in California, and the two primary California Outer Continental Shelf producing fields, Point Arguello and Santa Ynez, to the Los Angeles Basin and Bakersfield. The Pacific Terminals storage and distribution system is a crude oil and dark products storage and pipeline distribution system located in the Los Angeles Basin, and the PMT gathering system is a proprietary gathering operation in the San Joaquin Valley. The Pacific Atlantic terminals consist of the Martinez and Richmond terminals in the San Francisco, California area and the Paulsboro, New Jersey and Philadelphia area terminals. These terminals are refined product (and, in the case of Martinez, crude oil) storage and terminaling facilities. Additionally, we are currently seeking permits for the development of a deepwater petroleum import terminal at Pier 400 in the Port of Los Angeles, which we expect to begin constructing in mid 2007 (see Liquidity and Capital Resources Capital Requirements, Pier 400 for further discussion).

Our Rocky Mountain Business Unit consists of (i) the Rangeland system, (ii) certain undivided interests in the Western Corridor system, (iii) the Salt Lake City Core system, (iv) our interest in Frontier Pipeline Company, and (v) the Rocky Mountain Products Pipeline, which we acquired on September 30, 2005. Our Rocky Mountain crude oil pipeline systems transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. Deliveries are also made to the refining and marketing center of Edmonton, Alberta through our Rangeland system. Deliveries of crude oil are made to refineries directly through our pipelines or indirectly through connections with third-party pipelines. The Rocky Mountain Products Pipeline supplies refined products to the South Dakota, Wyoming and Colorado markets.

Proposed Merger With Plains All American Pipeline, L.P.

On June 12, 2006, we announced that we had entered into an agreement with Plains All American Pipeline, L.P. (PAA), Plains AAP, L.P., Plains All American GP LLC (PAA GP LLC), PEM, and Pacific Energy GP, LP, pursuant to which Pacific Energy Partners, L.P. will be merged with and into PAA. In the merger, each of our common unitholders, except LB Pacific, LP (LB Pacific), the owner of our General Partner, will receive 0.77 common units of PAA for each Pacific Energy Partners common unit that the unitholder owns. In addition, pursuant to a purchase agreement between LB Pacific and PAA, PAA will acquire from LB Pacific the general partner interest and incentive distribution rights of the Partnership as well as 5,232,500 common units and 5,232,500 subordinated units of Pacific Energy Partners for total consideration of $700 million in cash. The merger agreement was unanimously approved by the Board of Directors of PEM, as well as by the board of directors of PAA s general partner.

Each of us and PAA made customary representations, warranties and covenants in the merger agreement, which are described in the joint proxy statement/prospectus filed by us and PAA with the SEC. The merger is subject to the satisfaction or waiver of certain conditions, including the receipt of various regulatory approvals or the expiration of various regulatory waiting periods, all of which approvals or waiting periods have been obtained, and the adoption and approval of the merger agreement and the merger by the holders of at least a majority of our outstanding common units (excluding common units held by LB Pacific) and outstanding subordinated units, each voting as a separate class. The merger agreement and the merger must also be adopted and approved by the holders of at least a majority of PAA s outstanding common units.

The special meetings of unitholders of us and PAA to consider the merger agreement and the merger are scheduled to occur on November 9, 2006. Although we and PAA cannot be sure when all of the conditions to the merger will be satisfied, the parties expect to complete the merger on November 15, 2006 (assuming the proposals are approved by the unitholders and all other conditions to closing are satisfied).

Recent Business Developments

The Rocky Mountain Business Unit has accomplished several positive initiatives in 2006. The construction of the initiating facility for synthetic crude oil in Edmonton, Alberta was completed in March 2006, and initial movements of synthetic crude oil began immediately thereafter. This connection provides direct access to synthetic crude oil in Edmonton for delivery through our pipeline systems to U.S. Rocky Mountain refineries. In addition, to facilitate the movement and maintain the quality of synthetic crude oil, four (three 120,000 barrel and one 80,000 barrel) tanks were constructed at storage facilities along the Rangeland and Western Corridor systems.

The Rocky Mountain Business Unit, through one of our subsidiaries, Rocky Mountain Pipeline System LLC (RMPS), is constructing an expansion of its Salt Lake City Core crude oil pipeline system from the terminus of Frontier Pipeline near Evanston, Wyoming to the Salt Lake City, Utah, refining complex. The new 16-inch pipeline, which will be approximately 93 miles in length, will be constructed parallel to and share much of the right-of-ways of RMPS s existing U-Crude pipeline to Salt Lake City. The new pipeline is designed to transport multiple grades of crude oil in segregated batches, including Canadian heavy crude oil and synthetic crude oil. It will provide the capacity necessary to meet increasing crude oil demand in Salt Lake City, for the near-term and well into the future. The new pipeline will be constructed in two phases. The first phase, which will add 43.5 miles of pipeline and approximately 12,000 barrels per day of pumping capacity, is expected to be completed by year end 2006. Construction of the second phase, which will add the remaining 49.6 miles of pipeline, is expected to be completed in October 2007. Capacity of the completed pipeline will be approximately 95,000 barrels per day. The total cost for both phases of the project is expected to be approximately $77 million and is supported by 10-year transportation agreements that have been executed with four Salt Lake City refiners.

In addition, RMPS signed a transportation agreement with Frontier Oil and Refining Company pursuant to which RMPS is constructing a 24-inch crude oil pipeline, approximately 10 miles in length, from Guernsey, Wyoming to RMPS s Fort Laramie, Wyoming tank farm and a 16-inch crude oil pipeline, approximately 85 miles in length, from Fort Laramie to Frontier Oil s Cheyenne refinery, in exchange for Frontier Oil s ten-year firm commitment to ship 35,000 barrels per day on the new pipeline and lease approximately 300,000 barrels of storage capacity at Fort Laramie. The total project cost is estimated to be $59 million. The project began in the second quarter of 2006 and is expected to be completed in the second quarter of 2007. Initial capacity will be 55,000 barrels per day, which can be expanded to a capacity of 90,000 barrels per day.

In our West Coast Business Unit, we recently completed construction of 450,000 barrels of storage capacity at our Martinez terminal. In addition, due to strong demand, we increased our capital budget in the third quarter of 2006 to provide for the construction of an additional 850,000 barrels of storage capacity at the Martinez terminal for completion in 2007. At our Philadelphia area terminals, we have completed an ethanol expansion project which enabled us to increase our ethanol handling and blending capabilities and increase our marine receipt capabilities. At Pacific Terminals, we refurbished and placed in service 300,000 barrels of black oil storage capacity in the third quarter of 2006 and expect to complete refurbishing an additional 300,000 barrels of black oil storage in the first quarter of 2007. We are also making infrastructure changes to increase pumping capacity and improve operating efficiencies of various Pacific Terminals facilities, which we expect to complete in 2007.

In addition, we continue to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstocks. See Liquity and Capital Resources Capital Requirements Pier 400 for a discussion of the Pier 400 project.

Conversion of Subordinated Units

In August 2006, 2,616,250 of the Partnership s subordinated units were converted to common units pursuant to the terms of the partnership agreement of the Partnership.

Business Fundamentals

Pipeline Transportation

We generate pipeline transportation revenue by charging tariff rates for transporting crude oil and refined products on our common carrier pipelines. The fundamental items impacting our pipeline transportation revenue are the volume of crude oil and refined products, or throughput, we transport on our pipelines, and our tariff rates. Throughput on our pipelines fluctuates based on the volume of crude oil and refined products available for transportation on our pipelines, the demand for such products, refinery downtime, the availability of alternate sources of crude oil for the refineries we serve and the availability of refined products from other sources.

Our shippers determine the amount of crude oil and refined products we transport on our pipelines, but we can influence these volumes through the level and type of service we provide and the rates we charge. Our rates need to be competitive to transportation alternatives, which are mostly other pipelines.

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (CPUC). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual limitations. Tariffs on Line 63, which are cost-of-service based tariffs, are based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our U.S. Rocky Mountain crude oil pipelines are regulated by either the Federal Energy Regulatory Commission (FERC) or the Wyoming Public Service Commission (Wyoming PSC), generally under a cost-of-service approach. The FERC, Wyoming PSC, and the Colorado Public Utilities Commission each regulate various tariffs on the Rocky Mountain Products Pipeline, which include both cost and market based rates.

Although the tariff rates we charge on the system are regulated, competitive forces may also limit the amount of our filed rates. The FERC tariff rates are generally adjusted, effective July 1 of each year, by the amount of change in the Producer Price Index for Finished Goods, plus 1.3%.

Following are recent tariff rate increases on our pipelines:

- In September 2006, we filed an application with the CPUC requesting a 9.5% tariff increase on Line 63 with a proposed effective date of November 1, 2006.

- On July 1, 2006, we increased the FERC tariff rates on our U.S. Rocky Mountain crude oil and products pipelines by 6.1% based on the FERC index adjustment. In addition, tariff rates on the Reno to Casper/Guersney segment of the line were increased in a cost of service tariff rate filing.

- On May 1, 2006, we increased the tariff rates on our Line 2000 by approximately 7.1%.

- Effective August 1, 2005, we implemented a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover costs relating to the Line 63 oil release we experienced in 2005, together with other costs incurred or to be incurred as a result of rain-related earth movement and stream erosion.

- On July 1, 2005, we increased the FERC tariff rates on our U.S. Rocky Mountain crude oil pipelines by 3.6% based on the FERC index adjustment.

- On May 1, 2005 we increased the tariff rates on our Line 2000 by approximately 4.8%.

Tariff rate increases on our West Coast pipelines partially mitigate the impact of declining throughput on these pipelines.

The availability of crude oil for transportation on our pipelines is dependent, in part, on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain operations. With the passage of time, production of crude oil in an individual well naturally declines. Although this decline can, in the short term, be offset in whole or in part, by additional drilling or the implementation of recovery enhancement measures, in the San Joaquin Valley and in the California Outer Continental Shelf, total production is generally declining.

In the Rocky Mountains, our pipelines are connected to U.S. and Canadian sources of crude oil. Our Rangeland system in Alberta gives us access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any long term U.S. Rocky Mountain production declines and meet growing demand in the U.S. Rocky Mountain region. In recent months, production in the U.S. Rocky Mountains has increased with the increased amount of natural gas related drilling, which results in increased volumes of crude oil and condensate. We believe, however, that the longer term production of crude oil in the U.S. Rocky Mountains will resume its historical decline.

The Rocky Mountain Products Pipeline acquired in 2005 is a common carrier petroleum products pipeline and terminals network. The system generates revenues through transportation tariffs for volumes of petroleum products it ships. These tariffs vary depending upon where the product originates and where ultimate delivery occurs. The products terminals on the pipeline system also earn revenues by providing additional services.

Storage and Terminaling

We provide storage and terminaling services to refineries in the Los Angeles Basin and San Francisco areas in California and in the Philadelphia, Pennsylvania area. The fundamental items impacting our storage and terminaling revenue are the amount of storage capacity we have under lease, the lease rates for that capacity and the length of each lease.

Demand for crude oil storage capacity tends to be more stable over time and leases for crude oil storage capacity are usually long term (more than one year). Demand for storage capacity for other dark products is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for other dark products storage capacity are usually short term (less that one year). While Pacific Terminals   rates are subject to regulation by the CPUC, the CPUC has allowed Pacific Terminals to establish rates based on market conditions through negotiated contracts.

The Martinez, Richmond, Paulsboro and Philadelphia terminals that we purchased in September 2005 are refined product (and, in the case of Martinez, crude oil) storage and terminaling facilities that generate revenues primarily from fees that we charge customers for storage, throughput and other services. Demand for refined products storage capacity, mostly at the Philadelphia area terminals, depends on connections with refineries and petroleum products pipelines owned and operated by third parties.

Demand for refined products storage at our San Francisco area terminals tends to be stable over time as most of our lease contracts are evergreen contracts for a year or more. Additionally, the San Francisco area terminals are not overly reliant on local area refinery production to satisfy the supply of refined products. The San Francisco area terminals receive a significant volume of imported refined products and crude oil into the San Francisco harbor. One of our goals is to increase the storage capacity of our Martinez terminal. We recently completed construction of 450,000 barrels of storage, which we placed in service at the end of the third quarter of 2006. We also expect to complete construction of an additional 850,000 barrels of storage capacity at the Martinez terminal in 2007.

The throughput service business of our Philadelphia area terminals, which receive products from local refineries, the U.S. Gulf Coast and New York Harbor, is dependent on the demand for gasoline and other products in the Philadelphia market. In addition, our Philadelphia area terminals provide storage services for local refineries and other marketers.

Pipeline Buy/Sell Transportation

Throughput on our Rangeland system varies with many of the same factors described in Pipeline Transportation above.

We have made significant changes to the revenue-generating capability of the Rangeland system, which we acquired in mid-2004, by (i) combining and fully integrating all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, (ii) establishing connections with other pipelines, thereby expanding the throughput of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta, which began operating in March 2006. The volume of throughput originating at our Edmonton, Alberta, initiation station will vary with our success in attracting new supplies of synthetic crude oil to our system.

The Rangeland system operates as a proprietary system and, therefore, we take title to the crude oil that is gathered and transported. Pursuant to a transportation service agreement between two of our subsidiaries, Rangeland Marketing Company (RMC) and Rangeland Pipeline Partnership, RMC controls the entire capacity of Rangeland pipeline. Customers who wish to transport product on Rangeland pipeline must either: (i) sell product to RMC at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential; or (ii) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC.

Virtually all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy and Utilities Board (EUB). A short segment of the Rangeland system that connects to the Western Corridor system at the U.S.-Canadian border is subject to the jurisdiction of the Canadian National Energy Board (NEB). Neither the EUB nor the NEB will generally review rates set by a crude oil pipeline operator unless it receives a complaint relating to transportation rates.

Effective December 1, 2005, we increased the location differentials on the Rangeland pipeline by an average of 6.9%.

Gathering Activities and Marketing Business

Through our PMT subsidiary, we purchase, gather, and resell crude oil, principally in California s San Joaquin Valley and, to a much lesser extent, in the Rocky Mountain area in the vicinity of our pipelines. In the third quarter of 2005, we began selectively purchasing and reselling crude oil in other areas as well, although this is not a primary focus.

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In California, our PMT gathering system is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our pipeline transportation business. The gathering system effectively extends our pipeline network to capture supplies of crude oil bound for transportation to Los Angeles that might not otherwise be shipped through our pipelines. In the U.S. and Canadian Rocky Mountain area, PMT facilitates transportation on our Canadian and U.S. Rocky Mountain pipelines by purchasing crude oil from Canada for resale in the Rocky Mountain marketplace.

The contribution of our PMT subsidiary is, for several reasons, a variable part of our income. First, it varies with the price differential between the cost of the varying grades of crude oil that PMT buys for use in its gathering operations, and the price of the crude oil it sells. Costs and sales prices are generally impacted by crude oil prices, as well as by local supply and demand forces, including regulations affecting refined product specifications. Second, it varies with the price differential between crude oil purchased on one price basis and sold on another price basis. Third, it varies with the volumes gathered or purchased for sale. Finally, it varies with the effectiveness of our hedging program. We seek to control these variations through our risk management policy, which provides specific guidelines for our crude oil marketing and hedging activities and requires oversight by our senior management.

Operating Expenses

Many of our operating expenses, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, are relatively fixed and vary little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to operate pump stations along our pipelines or to operate our terminals. Major maintenance costs can vary depending on a particular asset s age and also with regulatory requirements, such as mandatory inspections at defined intervals. Unanticipated costs can include the costs of cleanup of any oil or product release, to the extent they are not covered by insurance, and repairs caused by severe weather as we experienced in California and Alberta, Canada, in 2005.

We do not have any employees, except in Canada. Our General Partner provides employees to conduct our U.S. operations. We and our General Partner collectively employ approximately 460 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey, terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us.

Impact of Foreign Exchange Rates

Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of each reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The reported cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary in U.S. dollar terms based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries underlying operating results. In addition, the amount of monies we repatriate from Canada will vary with fluctuations in currency exchange rates and may impact the cash available for distribution to our unitholders. We have entered into certain foreign exchange contracts to mitigate currency exchange risks (see Item 3 Quantitative and Qualitative Disclosures about Market Risk).

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet, as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 2, Significant Accounting Policies, to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2005) and estimates, the following may involve a higher degree of judgment and complexity:

- We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired and liabilities assumed (including environmental remediation liabilities). Additionally, we must determine whether an acquisition is to be treated as a purchase of a business or a set of net assets because excess purchase price is only allocated to goodwill in a business combination. Determination of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilized in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation and amortization expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment, as well as intangible assets such as customer relationships and contractual rights.

- We depreciate and amortize the components of our property and equipment and intangible assets on a straight-line basis over the estimated useful lives of the assets. The estimates of the assets useful lives require our judgment and our knowledge of the assets being depreciated and amortized. When necessary, the assets useful lives are revised and the impact on depreciation and amortization is adjusted on a prospective basis.

- We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated it is probable that cleanup costs are or will be required and may be reasonably estimated. In making these estimates, we consider information that is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions. We may use outside environmental consultants to assist us in making these estimates. We also are required to estimate the amount of any probable recoveries, including insurance recoveries. In addition, generally accepted accounting principles require us to establish liabilities for the costs of asset retirement obligations when a legal or contractual obligation exists to dispose of or restore an asset upon its retirement and the timing and cost of such work is reasonably estimable. We will record such liabilities only when such timing and costs are reasonably determinable.

- From time to time, a shipper or group of shippers or regulatory body may initiate regulatory proceedings or other actions challenging the tariffs we charge or have charged. In such cases, we assess the proceeding on an ongoing basis as to its likely outcome in order to determine whether to accrue for a future expense. We use outside regulatory lawyers and financial experts to assist us in these assessments.

- Our inventory of crude oil for our PMT gathering operations and marketing business, our Canadian operations, any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines and any inventory of refined products at our terminals is carried in our accounts at the lower of cost or market value, unless it is hedged, in which case it is carried at market. On any hedged portion, we are exposed to the potential that our hedges may not be perfectly effective. On any unhedged portion, we are exposed to the potential for a write-down to market value. To the extent we owe our customers crude oil or refined products, we are exposed to the potential of additional costs in the event market prices increase.

Results of Operations

Internally, in our analysis of operating results, we consider the impact of unusual items that we believe affect comparability between periods. We also believe that providing a discussion and analysis of our results that is comparable year over year provides a more accurate and thorough analysis of our results of operations. We have provided a reconciliation of net income to the results of our operations, excluding those unusual items, in our analyses below. Following is a description of each of the unusual items that impacted the results of our operations.

Merger costs. On June 12, 2006, we announced that we had entered into a merger agreement with *Plains* All American Pipeline, L.P., pursuant to which we will be merged into PAA. For the three and nine months ended September 30, 2006, we incurred $1.1 million and $4.5 million, respectively, in investment banking fees, legal fees and other transaction costs directly related to the merger.

Tax rate adjustments to net deferred tax liabilities. During the second quarter of 2006, the Canadian and Alberta governments enacted legislation that will reduce federal and provincial income taxes. We adjusted our estimate of future income tax rates in our estimates of deferred tax assets and liabilities and recognized a $4.6 million deferred tax benefit in the second quarter of 2006.

Line 63 oil release. On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS s Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, we recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of what we now estimate to be $25.5 million of total costs relating to the release, net of insurance recoveries of $18.6 million to date and accrued future net insurance recoveries of $4.6 million at September 30, 2006.

Accelerated long-term incentive plan compensation expense. On March 3, 2005, in connection with the change in control of our General Partner, all restricted units then outstanding under the Long-term Incentive Plan immediately vested. As a result, we recorded a $3.1 million compensation expense in the first quarter of 2005.

Reimbursed general partner transaction costs. Pursuant to an agreement entered into in connection with the sale of The Anschutz Corporation s (the owner of our General Partner before March 3, 2005) interest in us, LB Pacific, LP and The Anschutz Corporation reimbursed us $2.4 million for the cost incurred in connection with a consent solicitation prepared and delivered to the holders of our 7 1/8% senior notes to approve certain amendments to the governing indenture and for severance and other costs incurred in connection with the sale of our General Partner. In accordance with generally accepted accounting principles, we recorded $0.6 million as capitalized deferred financing costs and $1.8 million as an expense, both in the first quarter of 2005. The reimbursements were recorded as a capital contribution to the Partnership by our General Partner.

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005

Summary

Net income for the three months ended September 30, 2006 was $19.2 million, or $0.48 per diluted limited partner unit, compared to $12.2 million, or $0.39 per diluted limited partner unit, for the three months ended September 30, 2005.

Net income for the three months ended September 30, 2006 includes a full quarter of operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which we acquired on September 30, 2005.

Following is a reconciliation of net income to the results of our operations, excluding the unusual items mentioned above:

	Three Months Ended September 30, 2006 (In thousands)	2005	Change	Percent
Net income	$ 19,235	$ 12,166	$ 7,069	58 %
Add: Merger costs	1,112		1,112	
	$ 20,347	$ 12,166	$ 8,181	67 %
Diluted weighted average limited partner units	39,321	30,762	8,559	28 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline acquired on September 30, 2005, (ii) higher operating income on our West Coast pipelines, (iii) increased margins in our crude oil marketing business, and (iv) higher revenue from our Pacific Terminals storage facilities. These increases were partially offset by a decline in Rangeland s buy/sell transportation revenue. In addition, the increases in income were partially offset by higher interest expense primarily due to higher debt levels, and increased general and administrative costs. There were 39.3 million weighted average limited partner units outstanding in the three months ended September 30, 2006, approximately 28% more limited partner units than the 30.8 million weighted average units outstanding in the three months ended September 30, 2005. The higher debt levels and increased number of units reflect the funding of the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

Segment Information

The following is a discussion of segment operating income, which does not include general and administrative expenses, merger costs, accelerated long-term incentive compensation plan expense and reimbursed general partner transaction costs, as these items are not allocated to the West Coast and Rocky Mountain business units.

West Coast	**Three Months Ended September 30, 2006 (In thousands)**	**2005**	**Change**	**Percent**
Operating income	$ 24,152	$ 9,813	$ 14,339	146 %
Operating data:				
Pipeline throughput (bpd)	111.0	104.4	6.6	6 %

West Coast operating income was higher in 2006 due to (i) the result of operations of the Pacific Atlantic terminals, which were acquired in September 2005, (ii) higher pipeline transportation income, (iii) higher margins in our crude oil marketing business, and (iv) increased utilization, higher tank lease rates and lower operating expenses for our Pacific Terminals storage facilities.

Although there continue to be natural production declines of San Joaquin Valley Crude and Outer Continental Shelf crude oil, the West Coast pipeline volumes were approximately 6% higher in the third quarter of 2006 than in the corresponding quarter of 2005. In addition, as a result of a pipeline project completed in October 2005, we realized a substantial increase in deliveries to Bakersfield refineries, which volumes are not included in the statistic above. Additionally, tariff increases on Line 2000 and Line 63 increased West Coast pipeline transportation income.

Crude oil marketing income was significantly higher in the third quarter of 2006 than the corresponding period in 2005. Favorable margins and increased crude oil volumes in the third quarter of 2006 contributed to the improvement.

Rocky Mountains	Three Months Ended September 30, 2006 (In thousands)	2005	Change	Percent
Operating income	$ 12,173	$ 13,644	$ (1,471)	(11)%
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	19.7	19.3	0.4	2 %
Sundre South	48.5	48.1	0.4	1
Western Corridor system	26.6	26.8	(0.2)	(1)
Salt Lake City Core system	126.7	125.6	1.1	1
Frontier pipeline	46.2	49.6	(3.4)	(7)
Rocky Mountain Products Pipeline	59.2		59.2	

For the three months ended September 30, 2006, operating income was $12.2 million, compared to $13.6 million for the three months ended September 30, 2005. The $1.4 million decrease was primarily due to lower operating income for the Rangeland pipeline system in Alberta, partially offset by higher volumes on the Western Corridor system and the income contribution from the Rocky Mountain Products Pipeline that was part of the Valero L.P. acquisition. The decrease in Rangeland s third quarter 2006 income was due in part to the absence of an unusual item that benefited the 2005 quarter: the correction of an error in the procedures used to properly account for inventory and cost of goods sold that resulted in an increase in Rangeland s pre-tax income in the third quarter 2005 of $1.2 million ($0.7 million after tax).

Statement of Income Discussion and Analysis

Revenues	Three Months Ended September 30, 2006 (In thousands)	2005	Change	Percent
Pipeline transportation revenue	$ 36,995	$ 27,283	$ 9,712	36 %
Storage and terminaling revenue	23,467	9,731	13,736	141
Pipeline buy/sell transportation revenue	10,010	11,683	(1,673)	(14)
Crude oil sales, net of purchases:				
Crude oil sales	431,200	194,724	236,476	121
Crude oil purchases	(421,276)	(188,901)	232,375	123
Crude oil sales, net of purchases	9,924	5,823	4,101	70
Net revenue	$ 80,396	$ 54,520	$ 25,876	47 %

Pipeline transportation revenues in 2006 include revenues from our Rocky Mountain Products Pipeline, which was acquired in September 2005, and trucking revenues from the purchase of a crude oil trucking business in January 2006. In our West Coast Business Unit, transportation revenue was higher because of higher pipeline transportation volumes, higher tariff rates and increased deliveries to Bakersfield area refineries.

Storage and terminaling revenue increased in 2006 primarily because of the acquisition of the Pacific Atlantic terminals in September 2005. In addition, higher lease rates and greater utilization of our Pacific Terminals storage facilities also increased storage and terminaling revenue.

Pipeline buy/sell transportation revenues decreased in 2006 because of the correction of an error in 2005, which increased 2005 pipeline buy/sell transportation revenues by $1.2 million.

Crude oil sales net of purchases increased because of higher overall margins. Higher crude oil prices increased gross sales and purchases.

Expenses	**Three Months Ended September 30, 2006 (In thousands)**	**2005**	**Change**	**Percent**
Operating expenses	$ 34,046	$ 25,019	$ 9,027	36 %
General and administrative expense	5,649	4,115	1,534	37
Depreciation and amortization	10,398	6,560	3,838	59
Merger costs	1,112		1,112	
	$ 51,205	$ 35,694	$ 15,511	43 %

The increase in operating expenses was related primarily to the incremental operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which were acquired in September 2005.

The increase in general and administrative expense was primarily associated with the support of newly acquired assets, professional fees and $0.4 million of costs for the LB Pacific, LP option plan, which we are required by generally accepted accounting principles to record as our expense even though the plan is funded by LB Pacific, LP and not by the Partnership.

The increase in depreciation and amortization includes $3.3 million for depreciation on the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals acquired in September 2005.

Merger costs are discussed above.

Other Income and Expense	**Three Months Ended September 30, 2006 (In thousands)**	**2005**	**Change**	**Percent**
Share of net income of Frontier	$ 373	$ 516	$ (143)	(28)%
Interest expense	$ 10,853	$ 6,237	$ 4,616	74
Other income	$ 720	$ 494	$ 226	46
Income tax expense (benefit)	$ 196	$ 1,433	$ (1,237)	(86)

The decrease in our share of Frontier s net income was mainly attributed to higher operating costs at Frontier.

The increase in interest expense was due to additional borrowings incurred to partially fund the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline. Our weighted average borrowings during the three months ended September 30, 2006 were $650 million compared to $352 million in the corresponding period in 2005. Floating interest rates were slightly higher in 2006. Our weighted average interest rate was 7.1% for the period ended September 30, 2006, compared to a weighted average interest rate of 7.0% for the corresponding period in 2005. Capitalized interest was $0.8 million and $0.2 million for the three months ended September 30, 2006 and 2005, respectively.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities in Canada. In addition, certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. Income tax expense is lower as a result of lower income from our Canadian subsidiaries.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Summary

Net income for the nine months ended September 30, 2006 was $52.3 million, or $1.31 per diluted limited partner unit, compared to $27.8 million, or $0.96 per diluted limited partner unit, for the nine months ended September 30, 2005.

Net income for the nine months ended September 30, 2006 includes nine months of operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which were acquired on September 30, 2005.

Following is a reconciliation of net income to the results of our operations, excluding the unusual items mentioned above:

	Nine Months Ended September 30,			
	2006	**2005**	**Change**	**Percent**
	(In thousands)			
Net income	$ 52,292	$ 27,807	$ 24,485	88 %
Add: Merger costs	4,529		4,529	
Line 63 oil release costs		2,000	(2,000)	
Accelerated long-term incentive compensation expense		3,115	(3,115)	
Reimbursed general partner transaction costs		1,807	(1,807)	
Less: Tax rate adjustments to deferred tax liability	(4,560)		(4,560)	
	$ 52,261	$ 34,729	$ 17,532	50 %
Diluted weighted average limited partner units	39,332	30,089	9,243	31 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline acquired in September 2005; (ii) increased margins in our crude oil marketing business, (iii) higher pipeline transportation income in our West Coast Business Unit, and (iv) increased revenue from our Pacific Terminals storage facilities. These increases were partially offset by higher interest expense primarily due to higher debt levels and increased general and administrative costs. There were 39.3 million weighted average limited partner units outstanding in the nine months ended September 30, 2006, approximately 31% more limited partner units than the 30.1 million weighted average units outstanding in the nine months ended September 30, 2005, due to the sale of additional common units to partially fund the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

Segment Information

The following is a discussion of segment operating income. Segment operating income does not include general and administrative expenses, merger costs, accelerated long-term incentive compensation plan expense and reimbursed general partner transaction costs, as these items are not allocated to the West Coast and Rocky Mountain business units.

West Coast	**Nine Months Ended September 30, 2006 (In thousands)**	**2005**	**Change**	**Percent**
Operating income	$ 63,769	$ 31,962	$ 31,807	100 %
Add: Line 63 oil release cost		2,000	(2,000)	
	$ 63,769	$ 33,962	$ 29,807	88 %
Operating data:				
Pipeline throughput (bpd)	112.6	120.8	(8.2)	(7)%

West Coast operating income was higher in 2006 due to (i) the result of operations of the Pacific Atlantic terminals, which were acquired in September 2005, (ii) higher pipeline and transportation income due to increased deliveries to the Bakersfield, California refineries, higher tariff rates and lower repair and maintenance costs, (iii) increased utilization, greater capacity and higher lease rates for our Pacific Terminals storage facilities, and (iv) higher margins in our crude oil marketing business. Margins were above average in the 2006 period and below average in 2005 in our crude oil marketing business due to pricing pressures from steeply discounted crude oil imports, and an unfavorable purchase contract that expired on March 31, 2005. The nine month period of 2006 also reflects a full period of contribution from certain crude oil contracts we acquired on July 1, 2005. Partially offsetting these increases were lower West Coast long-haul pipeline volumes.

The decline in West Coast volumes during the nine month period ended September 30, 2006 was offset by tariff increases on Line 2000 and Line 63, and increased deliveries to the Bakersfield area, which volumes are not included in the statistic above. Reduced volumes on our West Coast pipelines were caused by lower San Joaquin Valley and Outer Continental Shelf production, third-party production problems, a shift of light crude being transported north to the San Francisco Bay area, which had previously been transported south on our pipelines to the Los Angeles area, and San Francisco area refinery turnarounds in the first half of 2005. We benefited from those turnarounds in 2005 because they increased volumes transported south on our pipelines to Los Angeles area refineries. Additionally, in 2005 we incurred $1.4 million of rain related repairs.

Rocky Mountains	**Nine Months Ended September 30, 2006 (In thousands)**	**2005**	**Change**	**Percent**
Operating income	$ 37,326	$ 32,183	$ 5,143	16 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	21.9	21.3	0.6	3 %
Sundre South	44.5	45.3	(0.8)	(2)
Western Corridor system	26.3	24.0	2.3	10
Salt Lake City Core system	125.3	119.8	5.5	5
Frontier pipeline	46.6	46.4	0.2	1
Rocky Mountain Products Pipeline	60.3		60.3	

For the nine months ended September 30, 2006, operating income was $37.3 million compared to $32.2 million for the nine months ended September 30, 2005. The increase included the results of operations of the Rocky Mountain Products Pipeline, which was acquired in September 2006. Higher volumes and tariffs on our U.S. Rocky Mountain pipelines also contributed to increased operating income.

Statement of Income Discussion and Analysis

Revenues	Nine Months Ended September 30, 2006	2005	Change	Percent
	(In thousands)			
Pipeline transportation revenue	$ 105,652	$ 83,067	$ 22,585	27 %
Storage and terminaling revenue	65,420	30,923	34,497	112
Pipeline buy/sell transportation revenue	31,136	28,905	2,231	8
Crude oil sales, net of purchases:				
Crude oil sales	1,058,638	439,380	619,258	141
Crude oil purchases	(1,031,185)	(425,733)	605,452	142
Crude oil sales, net of purchases	27,453	13,647	13,806	101
Net revenue	$ 229,661	$ 156,542	$ 73,119	47 %

We experienced higher pipeline transportation revenues on most of our pipelines in the nine month period ended September 30, 2006 than in the corresponding period of 2005. Pipeline transportation revenues in 2006 include revenues from our Rocky Mountain Products Pipeline, which was acquired in September 2005. In the Rocky Mountains, we experienced higher volumes and tariffs and increased trucking revenues from the purchase of a crude oil trucking business in January 2006. In our West Coast Business Unit, pipeline transportation revenue was improved by increased deliveries to Bakersfield, California refineries and higher tariffs.

Storage and terminaling revenues increased in the nine month period ended September 30, 2006 primarily because of the acquisition of the Pacific Atlantic terminals in September 2005. Increased utilization, greater capacity and increased lease rates for our Pacific Terminals storage facilities also favorably impacted storage and terminaling revenues.

Pipeline buy/sell transportation revenues increased because of increased location differentials and marketing margins.

Crude oil sales net of purchases increased because of the purchase of crude oil contracts in July 2005 and higher margins. Margins were above average in 2006 and below average in 2005 in our crude oil marketing business for reasons described above. Higher crude oil prices increased gross sales and purchases.

Expenses	Nine Months Ended Sepotember 30, 2006	2005	Change	Percent
	(In thousands)			
Operating expenses	$ 99,120	$ 72,065	$ 27,055	38 %
General and administrative expense	18,236	12,987	5,249	40
Depreciation and amortization	30,692	19,695	10,997	56
Merger costs	4,529		4,529	
Accelerated long-term incentive plan compensation expense		3,115	(3,115)	
Line 63 oil release costs		2,000	(2,000)	
Reimbursed general partner transaction costs		1,807	(1,807)	
	$ 152,577	$ 111,669	$ 40,908	37 %

The increase in operating expense was related primarily to the acquisition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals in September 2005. Operating expenses were also higher as a result of higher power costs.

The increase in general and administrative expense was primarily associated with the support of newly acquired assets, professional fees, and $1.3 million in costs for a new LB Pacific, LP option plan, which are required by generally accepted accounting principles to be recorded as our expense even though the plan is funded by LB Pacific, LP and not by the Partnership.

The increase in depreciation and amortization includes $9.7 million for depreciation on the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

Merger costs, accelerated long-term incentive plan compensation expense, Line 63 oil release costs and reimbursed general partner transaction costs are discussed above.

Other Income and Expense	Nine Months Ended September 30, 2006	2005	Change	Percent
	(In thousands)			
Share of net income of Frontier	$ 1,246	$ 1,363	$ (117)	(9)%
Interest expense	$ 30,029	$ 17,679	$ 12,350	70
Other income	$ 1,455	$ 1,387	$ 68	5
Income tax expense (benefit)	$ (2,536)	$ 2,137	$ (4,673)	(219)

The decrease in our share of Frontier s net income was mainly attributable to higher operating costs in the nine months ended September 30, 2006.

The increase in interest expense was primarily due to borrowings incurred to partially fund the acquisition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals. Our weighted average borrowings during the nine months ended September 30, 2006 were $617 million, compared to $359 million in the corresponding period in 2005. In addition, floating interest rates were higher in 2006. We realized a weighted average interest rate of 7.0% for the nine months ended September 30, 2006, compared to a weighted average interest rate of 6.6% for the corresponding period in 2005. Capitalized interest was $2.6 million and $0.6 million for the nine months ended September 30, 2006 and 2005, respectively.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities in Canada. In addition, certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. In the second quarter of 2006, the Canadian and Alberta governments enacted legislation that will reduce federal and provincial income taxes. We adjusted our estimate of future income tax rates in our estimates of deferred tax assets and liabilities and recognized a $4.6 million deferred tax benefit in the second quarter of 2006.

Liquidity and Capital Resources

We believe that cash generated from operations, together with our cash balance and our unutilized borrowing capacity, will be sufficient to meet our planned distributions, our working capital requirements and anticipated sustaining capital expenditures in the next three years.

We intend to finance our future acquisitions and development projects, including our Pier 400 project, with issuances of debt and equity securities. We expect to maintain a debt to total capitalization ratio of approximately 50% over time.

On December 23, 2005, we and certain of our subsidiaries filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as is determined by market conditions and our needs, of up to $1.0 billion of common units of the Partnership and debt securities of both the Partnership and certain subsidiaries. This shelf registration statement was to allow us to finance new acquisitions and new projects such as our Pier 400 Project.

In 2005, we received approval from the CPUC to dismantle certain idle PT assets and sell the underlying land. We sold one parcel of land in 2005 for $1.9 million, another in the fourth quarter of 2006 for $0.4 million, and expect to sell the remaining parcels in 2007. The remaining parcels of land have an estimated value of approximately $10 million, which exceeds their net book value.

Our ability to satisfy our debt service obligations, fund planned capital expenditures, make acquisitions, develop projects and pay distributions to our unitholders will depend upon our future operating performance. Our operating performance is primarily dependent on the volume of crude oil and refined products transported through our pipelines and the volume leased in our storage tanks, as described in Overview above. Our operating performance is also affected by prevailing economic conditions in the crude oil and refined products industries and financial, business and other factors, some of which are beyond our control, which could significantly impact future results.

The PAA merger agreement contains covenants which limit us in the conduct of our business, including but not limited to the following:

- We are limited to an aggregate of $150 million from the issuance of equity securities pending completion of the merger.
- Our quarterly distributions are limited to $0.5675 per unit.
- We are limited on the size of any potential acquisition and new project development.

Operating, Investing and Financing Activities

	Nine Months Ended September 30, 2006 (In thousands)	**2005**	**Change**
Net cash provided by operating activities	$ 49,491	$ 65,655	$ (16,164)
Net cash used in investing activities	(85,812)	(488,430)	402,618
Net cash provided by financing activities	31,889	424,954	(393,065)

Net cash provided by operating activities

Net cash from operating activities in 2006 was positively impacted by an increase in net income due to the operations of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals, which were acquired on September 30, 2005, higher pipeline transportation revenue, and increased margins in our crude oil marketing business. These increases were partly offset by higher general and administrative and interest expenses. Also included in net income is a $4.6 million non-cash tax rate adjustment for deferred taxes. Offsetting the increase in net income is an increase in the quantity of crude oil stored for our own account because of contango market conditions (when oil prices for future deliveries are higher than for current deliveries). In a contango market, we store crude oil purchased at lower prices in the current month for delivery at higher prices in future months, and protect such margin through hedging. In addition, we experienced a reduction in accounts payable and accrued liabilities in the nine months end September 30, 2006 compared to an increase in the corresponding period of 2005.

Net cash used in investing activities

We had capital expenditures of $67.5 million for the nine months ended September 30, 2006, which include (i) $44.2 million for expansion projects (see Capital Requirements below for a list of our projects and forecasted expansion expenditures in 2006), (ii) $13.3 million for the development of the Pier 400 project, (iii) $4.1 million related to sustaining capital projects, and (iv) $5.9 million of transition projects related to the Edmonton initiation station as well as transition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals to our operations. Additionally, we paid $16.1 million for pipeline linefill in connection with the start-up of our Edmonton initiation station and $2.3 million for a trucking business in the U.S. Rocky Mountains.

On September 30, 2005, we purchased certain terminal and pipeline assets from various subsidiaries of Valero, L.P. for an aggregate purchase of $455.0 million plus transaction costs of approximately $3.4 million, of which approximately $1.0 million was accrued at September 30, 2005. Separately, we also purchased certain crude oil contracts and crude oil inventories for approximately $3.8 million plus contingent payments over the next three and one half years based on specified performance criteria. Capital expenditures were $27.3 million in the nine months ended September 30, 2005, of which $3.1 million related to sustaining capital projects, $6.2 million related to transition projects, $13.1 million related to expansion, and $4.9 million was for our continued development of the Pier 400 project.

Net cash provided by (used in) financing activities

Net cash provided by financing activities for the nine months ended September 30, 2006 includes net borrowings of $100.6 million under our senior secured credit facility, which was used primarily to fund our expansion capital projects, contango inventory and pipeline linefill as describe above. We also distributed $68.7 million to our limited partners and General Partner during the nine months ended September 30, 2006.

Cash provided by financing activities for the nine months ended September 30, 2005 includes net proceeds of $295.2 million, including our General Partner contribution of $6.1 million, from our public and private equity offerings, $171.0 million net proceeds from the offering of our 6¼% senior notes, and net proceeds of $114.2 million under our new revolving credit facility. During the nine months ended September 30, 2005, we incurred net borrowings of $64.3 million under our previous U.S. and Canadian revolving credit facilities. In September 2005, we repaid in full the outstanding balance of $171.0 million under our previous U.S. and Canadian revolving credit facilities. Cash provided by financing activities for the nine months ended September 30, 2005 also includes distributions of $46.2 million which were made to the limited partners and the General Partner and a $2.4 million contribution from The Anschutz Corporation and LB Pacific, to reimburse us for certain costs incurred in connection with the sale of The Anschutz Corporation s interest in us.

Capital Requirements

Generally, our operations require investment to upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements consist primarily of:

- sustaining capital expenditures to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives;

- transitional capital expenditures to integrate acquired assets into our existing operations; and

- expansion capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition, such as placing new storage tanks in service to increase our storage capabilities and revenue, or adding new pump stations or pipeline connections to increase our transportation throughput and revenue.

We expect to invest approximately $119 million in total capital expenditures in 2006, with approximately $105 million of that total on expansion projects. Our estimated 2006 expansion capital spending includes the following notable projects:

2006 Forecast Expansion Capital Expenditures	**Estimated to be incurred in 2006 (in millions)**
2006 portion of the construction of a new pipeline to Cheyenne, Wyoming	$ 24
Capital projects associated with the new refined products assets	22
Completion of permitting process, engineering and other project development cost for the Pier 400 project	19
Phase I of Salt Lake City expansion	16
Reactivation of storage tanks and infrastructure enhancements at Pacific Terminals	12
Completion of storage tanks for the Rangeland System and Western Corridor pipeline to facilitate the transportation of synthetic crude oil	6
Other	6
Total	$ 105

In addition to the expansion projects above, we expect to incur $7 million for transitional capital expenditures and $7 million for sustaining capital expenditures during 2006.

Pier 400

We continue our efforts to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles (POLA) to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers, some directly, and some through our Pacific Terminals storage and distribution system. We would construct the storage tanks and transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels. If successful, this project will allow us to increase our participation in the Los Angeles basin marine import business, which is growing as a result of a decline in both California production and imports from Alaska.

We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The ConocoPhillips and Valero agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long term off-loading agreements with other potential customers.

We have failed to meet certain project milestone dates set forth in our Valero agreements, and we are likely to miss other project milestones that are approaching under these agreements. Valero has not given any indication that it will seek to terminate such agreements. We expect that ongoing negotiations with Valero to extend the milestone dates will be successful and that the Valero agreements will remain in effect.

In the first quarter of 2006, we completed an updated cost estimate for the project. We are estimating that Pier 400 will cost approximately $315 million, which is subject to change depending on various factors, including: (i) the final scope of the project and the requirements imposed through the permitting process; and (ii) changes in construction costs. This cost estimate assumes the construction of 4.0 million barrels of storage. We are in the process of securing the environmental and other permits that will be required for the Pier 400 project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in mid 2007.

Final construction of the Pier 400 project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. We expect construction of the Pier 400 terminal to be completed and the facility to be placed in service in the first quarter of 2009.

We have capitalized $31.6 million on the Pier 400 project through September 30, 2006, including $13.3 million for the nine months ended September 30, 2006. We anticipate funding the remaining permitting and pre-construction costs in 2006 from our revolving credit facility.

Debt Obligations

Our debt obligations are comprised of:

	September 30, 2006 (in thousands)	**December 31, 2005**
$400 million senior secured credit facility, bearing interest at 6.1% on September 30, 2006, due September 30, 2010	$ 244,316	$ 140,751
7 1⁄8% senior notes, due June 2014, net of unamortized discount of $3,628 and $3,882 and including fair value increases (decreases) of $(106) and $567, respectively	246,267	246,684
6 1⁄4% senior notes, due September 2015, net of unamortized discount of $738 and $782, respectively	174,262	174,218
Future payment for MAPL assets, net of unamortized discount of $165 and $309, respectively	4,318	3,979
Total long-term debt	$ 669,163	$ 565,632

As of September 30, 2006, $79 million of undrawn credit was available under the senior secured revolving credit facility. With the consent of the administrative agent under the revolving credit facility, we can increase credit availability up to an additional $58 million, based upon pro-forma EBITDA from future acquisitions.

Off-Balance Sheet Arrangements

As of September 30, 2006, we had standby letters of credit outstanding of $18 million for securing crude oil purchases and the MAPL note, both of which are reflected as liabilities on the balance sheet.

Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised December 2005), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first annual reporting period that begins after June 15, 2006. The adoption of SFAS 123R on January 1, 2006 did not have a material impact on our consolidated financial statements.

In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 will apply to the Partnership s Canadian subsidiaries, which are taxable entities in Canada, but not to the Partnership. The Partnership is in the process of determining the impact of FIN 48 on its financial statements, but does not expect it to have a material impact on its financial statements. FIN 48 is effective for the Partnership as of the beginning of the first fiscal year beginning after January 1, 2007.

In June 2006, the EITF issued Issue No. 06-3 (EITF 06-3), *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).* The issues addressed by the EITF are (i) Whether the scope of this Issue should include (a) all nondiscretionary amounts assessed by governmental authorities, (b) all nondiscretionary amounts assessed by governmental authorities in connection with a transaction with a customer, or (c) only sales, use, and value added taxes and (ii) How taxes assessed by a governmental authority within the scope of this Issue (Issue 1) should be presented in the income statement (that is, gross versus net presentation). EITF 06-3 is effective for interim and annual financial periods beginning after December 15, 2006. The Partnership is in the process of determining the impact of EITF 06-3 on its financial statements, but does not expect it to have a material impact on its financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements (SFAS 157).* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements in those accounting pronouncements. Accordingly, SFAS 157 does not require any new fair value measurements. However, the Partnership is in the process of determing what impact the application of SFAS 157 will have on its current fair value practices, but the Partnership does not expect the application of SFAS 157 to have a material impact. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current year Financial Statements* (SAB 108), which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. The guidance is effective for fiscal years beginning after November 15, 2006 and it allows a one-time transitional cumulative effect adjustment to beginning-of-year retained earnings at the first fiscal year ending after November 15, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The Partnership is currently evaluating the impact, if any, of adopting SAB 108 on its consolidated financial statements.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are commodity price risk, interest rate risk and currency exchange risk. We use derivative financial instruments to reduce our exposure to adverse fluctuations in commodity prices, interest rates and foreign exchange rates. We formally designate and document the financial instruments as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transactions. We formally assesses, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposure. All of our derivatives are commonly used over-the-counter instruments with liquid markets or are traded on the New York Mercantile Exchange. We do not enter into derivative financial instruments for trading or speculative purposes.

Commodity Price Risk Hedging

We may use derivatives, principally futures and options, to hedge our exposure to market price volatility related to our inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to the future sales of crude oil are generally classified as cash flow hedges. The values of derivative instruments are included in Other assets or in Other current liabilities in the accompanying consolidated balance sheets.

Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. For the nine months ended September 30, 2006 and 2005, crude oil sales, net of purchases were net of $0.8 million in gains and $1.7 million in losses, respectively, reflecting changes in the fair value of derivative instruments held as hedges related to crude oil marketing activities. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. Changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in accumulated other comprehensive income, a component of partners capital in the balance sheet, until the related revenue is reflected in the consolidated statements of income. As of September 30, 2006, $0.3 million relating to the change in the fair value of highly effective derivative instruments was included in accumulated other comprehensive income and is expected to be reclassified into earnings within one year. Since these amounts are based on market prices at September 30, 2006, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

Interest Rate Risk Hedging

In connection with the issuance of our 7⁄8% senior notes due 2014, we entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7⁄8% and to pay interest at an average variable rate of nine month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are

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callable at the same dates and terms as the 7⅛% senior notes. We designated these swaps as a hedge of the change in the senior notes fair value attributable to changes in the nine month LIBOR interest rate. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of the underlying $80.0 million of senior notes, which are expected to be offsetting to changes in the fair value of the interest swaps, are recorded into earnings each period. At September 30, 2006, we recorded a decrease of $0.1 million in the fair value of interest rate swaps. For the three and nine months ended September 30, 2006, we recognized reductions in interest expense of $0.1 million and $0.1 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. For the nine months ended September 30, 2006 and 2005, we had an immaterial amount of ineffectiveness relating to these interest rate swaps.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the $80 million interest swap on the senior notes are based on variable rates. If our interest rates were to increase 1.0% for the remainder of 2006 as compared to the rate at December 31, 2005, our interest expense for the remainder of 2006 would increase $0.8 million based on our outstanding debt balances at September 30, 2006.

Currency Exchange Rate Risk Hedging

The purpose of our foreign currency hedging activities is to reduce the risk that our cash inflows resulting from interest payments from our Canadian subsidiaries on intercompany debt will be adversely affected by changes in the U.S./Canadian exchange rate.

We entered into forward exchange contracts to hedge receipt of forecasted interest payments denominated in Canadian dollars. The effective portion of the change in fair value of this contract, which has been designated as a cash flow hedge, is reported in accumulated other comprehensive income in the accompanying balance sheet and will be reclassified into earnings in Other income in the same period during which the hedged transaction affects earnings. The ineffective portion, if any, of the change in fair value of this instrument will be immediately recognized in earnings. These foreign exchange contracts as of September 30, 2006 are as follows:

	Canadian dollars (in thousands)	US dollars	Average Exchange Rate
2006	$ 1,850	$ 1,580	Cdn$1.17 to U.S. $1.00
2007	6,600	5,662	Cdn$1.17 to U.S. $1.00
2008	3,193	2,754	Cdn$1.16 to U.S. $1.00

Credit Risks

By using derivative financial instruments to hedge exposures related to changes in commodity prices, interest rates and currency exchange rates, we expose ourselves to market risk and credit risk. Market risk is the risk of loss arising from the adverse effect on the value of a financial instrument that results from changes in commodity prices, interest rates or currency exchange rates. The market risk associated with price volatility is managed by established parameters that limit the types and degree of market risk that may be undertaken.

Credit risk is the risk of loss arising from the failure of the derivative agreement counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty is liable to us, which creates credit risk for us. When the fair value of a derivative agreement is negative, we are liable to the counterparty and, therefore, it creates credit risk for the counterparty. The counterparties we transact with are large, well known companies in the industry or large creditworthy financial institutions. As such, we believe our exposure to counterparty credit risk is low. Nonetheless, there can be no assurance as to the performance of a counterparty.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to us, including our consolidated subsidiaries, is made known to the officers who certify our financial reports and to other members of our senior management and our Board of Directors. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Based on their evaluation as of September 30, 2006, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Internal Control Over Financial Reporting

Our management, including the Chief Executive Officer and Chief Financial Officer, have evaluated our internal control over financial reporting as of September 30, 2006, and have concluded that there has not been any change during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

See discussion of legal proceedings in Note 4 Contingencies in the accompanying condensed consolidated financial statements.

On or about March 17, 2006, one of the Partnership s subsidiaries, Pacific Pipeline System LLC (PPS), was served with a four count misdemeanor action, entitled *The People of the State of California v. Pacific Pipeline System, LLC* , Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. These alleged violations relate to the release of crude oil from PPS s Line 63 into Pyramid Lake (see Note 4 Contingencies in the accompanying condensed consolidated financial statements). The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum fine that can be assessed is estimated to be approximately $870,000, in the aggregate. This amount is subject to downwards adjustment as additional information becomes known with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine after considering mitigating factors such as the fact that the release was not caused by any wrongful conduct of PPS. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained.

The penalties that could be assessed for the alleged California Water Code violations are also not readily quantifiable, but we believe the penalties would not exceed $50,000, in the aggregate. We believe, however, that the allegations of Water Code violations are without merit and intend to vigorously defend against them.

On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, entitled *Kosseff v. Pacific Energy, et al,* case no. BC 3544016. The plaintiff alleged that he was a unitholder of the Partnership and he sought to represent a class comprising all of the Partnership s unitholders. The complaint named as defendants the Partnership and certain of the officers and directors of the Partnership s general partner, and asserted claims of self-dealing and breach of fiduciary duty in connection with the pending merger with PAA and related transactions. The plaintiff sought injunctive relief against completing the merger or, if the merger was completed, rescission of the merger, other equitable relief, and recovery of the plaintiff s costs and attorneys fees. On September 14, 2006, the Partnership and the other defendants entered into a memorandum of settlement with the plaintiff to settle the lawsuit. As part of the settlement, the Partnership and the other defendants deny all allegations of wrongdoing and maintain that they are willing to settle the lawsuit solely because the settlement would eliminate the burden and expense of further litigation. The settlement is subject to customary conditions, including court approval. As part of the settlement, the Partnership will, subject to the consummation of the merger, pay $475,000 to the plaintiff s counsel for their fees and expenses, and incur approximately $0.1 to $0.2 million for costs of mailing materials to unitholders. If finally approved by the court, the settlement will resolve all claims that were or could have been brought on behalf of the proposed settlement class in the actions being settled, including all claims relating to the merger, the merger agreement and any disclosure made by the Partnership in connection with the merger. The settlement will not change any of the terms or conditions of the merger.

ITEM 1A. Risk Factors

The risk factors included in our annual report on Form 10-K for the year ended December 31, 2005 have not materially changed with the exception of the addition of risk factors related to the proposed merger with PAA. Some of the risks which may be relevant to us include:

Business Uncertainties and Contractual Restrictions While Merger is Pending ***Uncertainty*** about the effect of the merger on employees, suppliers, partners, regulators and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is consummated, and could cause suppliers, customers and others that deal with us to defer purchases or other decisions concerning us, or seek to change existing business relationships with us. Employee retention may be particularly challenging while the merger is pending, as employees may experience uncertainty about their future roles with PAA. In addition, the merger agreement restricts us from making certain acquisitions and taking other specified actions without PAA s approval. These restrictions could prevent us from pursuing attractive business opportunities that may arise prior to the completion of the merger.

Failure to Complete Merger Could Negatively Impact Stock Price, Future Business and Financial Results ***Although*** we have agreed that our Board of Directors will, subject to fiduciary exceptions, recommend that our unitholders approve and adopt the merger agreement, there is no assurance that the merger agreement and the merger will be approved, and there is no assurance that the other conditions to the completion of the merger will be satisfied. If the merger is not completed, we will be subject to several risks, including the following:

- we may be required to pay PAA a termination fee of $40 million in the aggregate if the merger agreement is terminated under certain circumstances and we enter into or complete an alternative transaction;

- the current market price of our common units may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a negative perception by the stock market of us generally and a resulting decline in the market price of our common units;

- certain costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by us whether or not the merger is completed;

- there may be substantial disruption to our business and a distraction of our management and employees from day-to-day operations, because matters related to the merger (including integration planning) may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to us;

- our business could be adversely affected if we are unable to retain key employees or attract qualified replacements; and

- we would continue to face the risks that we currently face as an independent company.

There are substantial risks and uncertainties relating to the pending merger between the Partnership and PAA and the combined company following the merger. A joint proxy statement/prospectus relating to the merger was filed by the Partnership and PAA and was declared effective by the SEC on September 29, 2006, and was subsequently sent to unitholders of the Partnership. This joint proxy statement/prospectus includes a discussion of these risks. Investors and security holders are urged to carefully read the joint proxy statement/prospectus because it contains important information, including detailed risk factors, regarding the Partnership, PAA and the merger. Investors and security holders may obtain a free copy of the definitive joint proxy statement/prospectus and other documents containing information about the Partnership and PAA, without charge, at the SEC s web site at www.sec.gov. Copies of the definitive joint proxy statement/prospectus and the SEC filings that are incorporated by reference in the joint

proxy statement/prospectus may also be obtained free of charge by directing a request to the Partnership or PAA. The Partnership or PAA and the officers and directors of the respective general partners of the Partnership and PAA may be deemed to be participants in the solicitation of proxies from their security holders in connection with the proposed transaction. Information about these persons can be found in the Partnership s or PAA s respective Annual Reports on Form 10-K and Form 10-K/A filed with the SEC, and additional information about such persons may be obtained from the joint proxy statement/prospectus. The Partnership urges unitholders and potential purchasers of its common units to review these materials.

ITEM 6. Exhibits

The following documents are filed as exhibits to this quarterly filing:

Exhibit Number	**Description**
*Exhibit 31.1	Certification of Principal Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
*Exhibit 31.2	Certification of Principal Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
Exhibit 32.1	Certification of Chief Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
Exhibit 32.2	Certification of Chief Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

* Filed herewith.

Not considered to be filed for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

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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.

PACIFIC ENERGY PARTNERS, L.P.	
By:	**PACIFIC ENERGY GP, LP,** **its general partner**
By:	**PACIFIC ENERGY MANAGEMENT LLC,** **its general partner**
By:	/s/ IRVIN TOOLE, JR. Irvin Toole, Jr. *President, Chief Executive Officer and Director* *(Principal Executive Officer)* *November 3, 2006*
By:	/s/ GERALD A. TYWONIUK Gerald A. Tywoniuk *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer)* *November 3, 2006*

EXHIBIT INDEX

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