PACIFIC ENERGY PARTNERS LP
Form 10-Q
November 08, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

ý **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended September 30, 2004

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 1-313345

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	**68-0490580** (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)

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 ý No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ý No o

There were 19,121,638 of the registrant s Common Units and 10,465,000 of the registrant s Subordinated Units outstanding at September 30, 2004.

PACIFIC ENERGY PARTNERS, L.P.

FORM 10-Q

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PACIFIC ENERGY PARTNERS, L.P. (Note 1)

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14,528	$ 9,699
Crude oil sales receivable	35,470	33,766
Transportation and storage accounts receivable	21,071	16,828
Canadian value added tax receivable	7,099	
Crude oil inventory	10,637	2,272
Spare parts inventory	1,637	1,644
Prepaid expenses	5,799	4,182
Other	1,736	405
Total current assets	97,977	68,796
Property and equipment, net	713,351	567,954
Investment in Frontier	7,841	6,886
Other assets	48,771	6,567
	$ 867,940	$ 650,203
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 9,291	$ 6,933
Accrued crude oil purchases	32,443	31,602
Accrued interest	5,448	2,690
Accrued insurance	3,428	1,883
Due to related parties (note 6)	374	580
Derivatives liability current portion	2,537	4,986
Other	7,490	1,317
Total current liabilities	61,011	49,991
Senior notes and credit facilities, net of unamortized discount of $4,278 at September 30, 2004 (note 3)	341,493	298,000
Deferred income taxes	36,641	
Derivatives liability		622
Other liabilities	7,185	6,523
Total liabilities and deferred income taxes	446,330	355,136
Commitments and contingencies (note 8)		
Partners capital (note 5):		
	364,702	246,952

Common unitholders (19,121,638 and 14,441,763 units outstanding at September 30, 2004 and December 31, 2003, respectively)						
Subordinated unitholders (10,465,000 units outstanding at September 30, 2004 and December 31, 2003)			43,631			49,010
General Partner interest			6,389			3,975
Undistributed employee long-term incentive compensation			957			738
Accumulated other comprehensive income (loss)			5,931			(5,608)
Net partners capital			421,610			295,067
		$	867,940		$	650,203

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands, except per unit amounts) (unaudited)			
Pipeline transportation revenue	$ 28,160	$ 25,501	$ 79,879	$ 76,579
Storage and distribution revenue	8,391	4,710	27,773	4,710
Pipeline buy/sell transportation revenue	7,972		11,662	
Crude oil sales, net of purchases of $103,192 and $96,833 for the three months ended September 30, 2004 and 2003 and $278,689 and $271,554 for the nine months ended September 30, 2004 and 2003	3,568	5,907	14,436	16,516
Net revenue before operating expenses	48,091	36,118	133,750	97,805
Expenses:				
Operating	22,589	16,630	62,189	43,622
Transition costs	199		383	397
General and administrative	3,762	3,305	11,252	10,289
Depreciation and amortization	6,821	5,049	17,776	13,435
	33,371	24,984	91,600	67,743
Share of net income of Frontier	406	414	1,190	1,141
Operating income	15,126	11,548	43,340	31,203
Interest expense	(5,234)	(4,782)	(13,743)	(12,930)
Write-off of deferred financing cost and interest rate swap termination expense (note 4)			(2,901)	
Other income	219	113	606	360
Income before income taxes	10,111	6,879	27,302	18,633
Income tax expense:				
Current	118		150	
Deferred	103		57	
	221		207	
Net income	$ 9,890	$ 6,879	$ 27,095	$ 18,633
Net income for the general partner interest	$ 198	$ 138	$ 542	$ 373
Net income for the limited partner interests	$ 9,692	$ 6,741	$ 26,553	$ 18,260
Basic net income per limited partner unit	$ 0.33	$ 0.30	$ 0.95	$ 0.85
Diluted net income per limited partner unit	$ 0.33	$ 0.30	$ 0.94	$ 0.84
Weighted average limited partner units outstanding:				
Basic	29,574	22,532	28,008	21,470
Diluted	29,682	22,725	28,125	21,648

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P. (Note 1)

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

	Limited Partner Units		Limited Partner Amounts		General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income (Loss)	Total
	Common	Subordinated	Common	Subordinate				
			(in thousands) (unaudited)					
Balance, December 31, 2003	14,442	10,465	$ 246,952	$ 49,010	$ 3,975	$ 738	$ (5,608)	$ 295,067
Net income			16,627	9,926	542			27,095
Distribution to partners			(25,659)	(15,305)	(836)			(41,800)
Issuance of common units, net of fees and offering expenses (note 5)	4,625		125,881					125,881
General partner contribution related to issuance of common units (note 5)					2,690			2,690
Undistributed employee compensation under long-term incentive plan						1,777		1,777
Issuance of common units pursuant to long-term incentive plan	55		901		18	(1,558)		(639)
Foreign currency translation adjustment							7,742	7,742
Change in fair value of hedging derivatives							3,797	3,797
Balance, September 30, 2004	19,122	10,465	$ 364,702	$ 43,631	$ 6,389	$ 957	$ 5,931	$ 421,610

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P. (Note 1)

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Net income	$ 9,890	$ 6,879	$ 27,095	$ 18,633
Change in fair value of hedging derivatives	(1,107)	4,143	3,797	(845)
Foreign currency translation adjustment	5,313		7,742	
Comprehensive income	$ 14,096	$ 11,022	$ 38,634	$ 17,788

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2004	2003
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 27,095	$ 18,633
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	17,776	13,435
Amortization of debt issue costs and accretion of bond discount	1,100	745
Write-off of deferred financing cost	2,321	
Non-cash portion of employee compensation under long-term incentive plan	1,120	1,955
Deferred tax expense	57	
Share of net income of Frontier	(1,190)	(1,141)
Distributions from (Contributions to) Frontier, net	(44)	1,777
	48,235	35,404
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(1,704)	(3,519)
Transportation and storage accounts receivable	(3,318)	(3,696)
Other current assets and liabilities	(13,834)	970
Accounts payable and other accrued liabilities	12,194	2,804
Accrued crude oil purchases	841	758
Other non-current assets and liabilities	(400)	680
	(6,221)	(2,003)
NET CASH PROVIDED BY OPERATING ACTIVITIES	42,014	33,401
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(139,000)	(159,939)
Additions to property and equipment	(11,522)	(2,320)
Other	(621)	137
NET CASH USED IN INVESTING ACTIVITIES	(151,143)	(162,122)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses	125,881	131,716
Capital contributions from the general partner	2,708	1,955
Redemption of common units held by the general partner, net of underwriter s fees		(40,780)
Net proceeds from senior notes offering	241,086	
Repayment of term loan	(225,000)	
Proceeds from bank credit facilities	157,924	149,000
Repayment of bank credit facilities	(145,453)	(90,000)
Deferred bank financing costs	(1,388)	
Distributions to partners	(41,800)	(29,657)
NET CASH PROVIDED BY FINANCING ACTIVITIES	113,958	122,234
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,829	(6,487)
CASH AND CASH EQUIVALENTS, beginning of reporting period	9,699	23,873
CASH AND CASH EQUIVALENTS, end of reporting period	$ 14,528	$ 17,386

Supplemental disclosures:						
Cash paid for interest		$	10,686		$	11,716
Non-cash financing and investing activities:						
Change in fair value of hedging derivatives		$	3,797		$	(845)
Foreign currency translation adjustment		$	7,742		$	
Issuance of common units upon vesting pursuant to long-term incentive plan		$	1,558		$	1,473
Addition to equipment		$			$	124

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2004

(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Pacific Energy Partners, L.P. and its subsidiaries (the Partnership) are engaged principally in the business of gathering, transporting, storing and distributing crude oil and related products in California and the Rocky Mountain region of the U.S. and Canada. The Partnership generates revenue primarily by transporting crude oil on its pipelines and by leasing storage capacity. The Partnership also buys, blends and sells crude oil, activities that are complementary to the Partnership s pipeline transportation business. The Partnership operates primarily in California, Colorado, Montana, Wyoming and Utah in the United States, and in Alberta, Canada and conducts its business through two regional operating units: West Coast operations and Rocky Mountain operations.

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 three and nine months ended September 30, 2004 and 2003 are not necessarily indicative of the results of operations for the full year. The financial data for the three and nine months ended September 30, 2004 and 2003 is derived from the Partnership s unaudited condensed consolidated financial statements. The financial data as of December 31, 2003 is derived from the Partnership s audited consolidated financial statements. All significant intercompany balances and transactions have been eliminated during the consolidation process.

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 for the year ended December 31, 2003.

Revenue Recognition

During the second quarter of 2004, the Partnership completed the acquisition (see Note 2 Acquisitions below) of the Rangeland Pipeline system and the Mid-Alberta pipeline (the MAPL pipeline). Revenue from the Rangeland Pipeline system (including the MAPL pipeline) is

recognized upon delivery of the crude oil, condensate and butane to the customer. Customers who wish to transport product on the Rangeland Pipeline system may either: (i) sell product at the inlet to the pipeline without repurchasing product; or (ii) sell product 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 on a pre-arranged basis.

Derivative Instruments

The Partnership uses, on a limited basis, certain derivative instruments (principally futures and options) to hedge its minimal exposure to market price volatility related to its crude oil 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 future sale of crude oil are generally designated as cash flow hedges. The Partnership does not engage in speculative derivative activities. Derivative instruments are included in other assets in the accompanying consolidated balance sheets.

Changes in the fair value of the Partnership s derivative instruments related to crude oil inventory are recognized in net income. Crude oil sales, net of purchases were net of a loss of $1.7 million for the three months ended September 30, 2004 and an immaterial amount for 2003, and $2.3 million and $0.3 million for the nine months ended September 30, 2004 and 2003, respectively, reflecting changes in the fair value of derivative instruments held for crude oil marketing activities. Changes in the fair value of the Partnership s derivative instruments related to the future sale of crude oil are deferred and

reflected in accumulated other comprehensive income, a component of partners capital, until the related revenue is included in the consolidated statements of income. As of September 30, 2004, $1.8 million relating to the changes in the fair value of highly effective derivative instruments was included in accumulated other comprehensive income and is expected to be reclassified to earnings in 2004.

In August and September 2002, the Partnership entered into three interest rate swap agreements that were to mature in 2009, with notional amounts of $140.0 million, and two interest rate swap transactions that were to mature in 2007, with notional amounts of $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under the term loan facility. The average swap rate on this $170.0 million of debt was approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 6.50% (including the applicable margin of 2.25%). In June 2004, in conjunction with the issuance of the 7.125% Senior Notes and the repayment of the term loan, the Partnership bought back the swaps for a loss of $0.6 million.

In connection with the issuance of the 7.125% Senior Notes, the Partnership entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six 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 callable at the same dates and terms as the 7.125% Senior Notes. The Partnership designated these swaps as a hedge of the change in the Senior Notes fair value attributable to changes in the six 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 are recorded into earnings each period. During the three months ended September 30, 2004, we recognized reductions in interest expense of $0.7 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. During the quarter ended September 30, 2004, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a gain of approximately $2.9 million at September 30, 2004.

Foreign Currency Translation

The financial statements of operating subsidiaries in Canada are measured using the Canadian dollar as the functional currency. Balance sheet amounts are translated at the end of period exchange rate. Income statement and cash flow amounts are translated at the average exchange rate for the period. Adjustments from translating these financial statements into U.S. dollars are accumulated in the equity section of the balance sheet under the caption, accumulated other comprehensive income (loss).

Income Taxes

The Partnership and its U.S. subsidiaries are not taxable entities and are not subject to federal or state income taxes as the tax effect of operations is accrued to its unitholders. The Partnership s Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, monies repatriated from Canada into the U.S. may be subject to withholding taxes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership s First Amended and Restated Agreement of Limited Partnership, as amended.

Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized to reflect 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 on deferred tax assets and liabilities of a change in tax rates is recognized in net income in the period that includes the enactment date.

Pursuant to FAS No. 109, Accounting for Income Taxes , in the second quarter of 2004, the Partnership recorded a deferred tax liability of $33.9 million, representing the tax effect of the difference between the amounts paid for shares of certain entities that owned the assets that comprise the Rangeland Pipeline system (see Note 2 Acquisitions below), and the underlying tax basis of the assets.

Net Income per Unit

Basic net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner 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 except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding unit options and restricted units by application of the treasury stock method. Set forth below is a reconciliation of the basic weighted average outstanding limited partner units to diluted weighted average outstanding limited partner units.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Basic weighted average limited partner units	29,574	22,532	28,008	21,470
Effect of restricted units	93	181	102	170
Effect of unit options	15	12	15	8
Diluted weighted average limited partner units	29,682	22,725	28,125	21,648

Reclassifications

Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to the current year presentation.

2. ACQUISITIONS

Rangeland

On May 11, 2004, the Partnership completed the acquisition of all of the outstanding shares of Rangeland Pipeline Company (RPC), Rangeland Marketing Company (RMC) and Aurora Pipeline Company Ltd. (APC), the corporations that owned various components of the Rangeland Pipeline System and the related marketing business from BP Canada Energy Company (BP). The Rangeland Pipeline System is located in the province of Alberta, Canada. The purchase price for the shares of RPC, RMC and APC was Cdn$130 million plus approximately Cdn$29 million for linefill, working capital, transaction costs and transition capital expenditures. The aggregate purchase price was approximately U.S. $116 million and was funded through a combination of proceeds from the Partnership s March 30, 2004 equity offering and a Cdn$45 million borrowing from a new Cdn$100 million revolving credit facility in Canada. The acquisition was accounted for as an acquisition of assets.

The majority of the Rangeland Pipeline System was constructed in 1966 with smaller portions being built as early as 1955 and certain pump stations built as late as 1971. The Partnership is depreciating the pipeline over forty years from the purchase date.

Pursuant to a transportation service agreement between RMC, RPC and APC, RMC has contracted for the rights to the entire capacity of the Rangeland pipeline. Customers who wish to transport product on the Rangeland pipelines may, therefore, either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) 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. RMC owns the buy/sell contracts with customers, which were assumed with the purchase, but the marketing function was conducted by employees of BP to whom we were not able to and did not offer employment.

The Rangeland Pipeline System has historically been operated without regard to maximizing either pipeline throughput or profitability; rather, it was operated as an integral part of a larger marketing and trading oriented enterprise. Similarly the MAPL Pipeline, which the Partnership also purchased (see Mid Alberta Pipeline below), was not operated with regard to maximizing pipeline operations or profitability; it was operated as a cost center in a larger enterprise. The Partnership intends to make significant changes to the revenue-generating capability of both systems by combining and integrating fully all of its Canadian and U.S. Rocky Mountain pipeline systems under common management, by expanding the throughput capacity of

the MAPL system and by connecting into other pipelines and establishing a new pump station and receiving terminal in Edmonton, Alberta. This new facility will be able to access additional sources of Canadian crude oil, which will allow the Partnership to participate in transporting the projected increase in production of Canadian synthetic crude oil.

In effect, the Partnership is converting what has been primarily a gathering system for crude oil, condensate and butane in southern Alberta into a trunk line transportation system that will be able to transport multiple grades of conventional and synthetic crude oils from the Edmonton oil hub to U.S. Rocky Mountain refining centers.

Until April 2003, the assets comprising the Rangeland Pipeline System were held by three legal entities: BP, APC and BP Canada Energy Resources Company (BPR). In April 2003, in order to facilitate their sale, BPR formed RPC and RMC, and transferred the Rangeland pipeline and marketing assets to the newly formed entities. APC, which contains only a short segment of pipeline and *de minimis* other assets, liabilities, revenues and expenses, remained unchanged. None of RPC, RMC or APC ever had any employees of their own. All operations and administrative and technical support functions associated with the Rangeland pipeline system, including field services and operations, executive management, marketing, engineering, environmental, risk management, payroll, treasury, human resources and legal remained with BPR and BP. These included services provided by approximately 90 BP employees who also provided varying amounts of support for BP s other pipelines.

Although the RPC and RMC legal entities were formed in April 2003, revenues, expenses, and other financial measures continued to be included within the financial statements of BPR and BP. Financial statements for RPC, RMC and Aurora were not maintained on a current basis.

Upon closing of the purchase transaction, BP terminated employees directly involved in the operation of the Rangeland Pipeline System, including field-level supervisors, and the Partnership hired those who accepted an offer of employment. Except for one former marketing person (who had not been directly involved with marketing of the Rangeland Pipeline System for several years), no members of senior management, and no financial, marketing or technical personnel who had been associated with the management and support of the Rangeland system were made available by BP for possible employment with the Partnership following the completion of this acquisition. Consequently, the Partnership hired its own marketing, accounting and technical staffs, which are located in its new Calgary office or in Olds, Alberta. The Partnership also utilizes its existing executive and support staff in Long Beach, California and Denver, Colorado to provide management oversight and administrative and technical support for the Alberta assets.

The existing accounting software and computer hardware were not included with the assets purchased by the Partnership. The Partnership was able, however, to acquire as part of the transaction, the Supervisory Control and Data Acquisition (SCADA) system necessary to operate the pipeline. Subsequent to the closing, the Partnership acquired software associated with the complex task of volumetric and revenue accounting from the seller for no additional consideration. The Partnership will use its existing financial accounting software for other accounting functions.

Mid Alberta Pipeline

On June 30, 2004, the Partnership completed the acquisition of the MAPL Pipeline from Imperial Oil. The MAPL pipeline is located in Alberta, Canada. The purchase price for MAPL was Cdn$31.5 million, of which Cdn$5.0 million is payable June 30, 2007. In addition to the MAPL pipeline, the Partnership acquired linefill for Cdn$5.0 million. The aggregate purchase price, including linefill, transaction costs and first-year construction costs, was approximately U.S. $30 million, most of which was funded from the Partnership s existing Canadian credit facility.

The first section of MAPL pipeline was constructed in 1960 and other sections were constructed in 1985 and 1994. The Partnership anticipates depreciating the pipeline over forty years from the date of purchase.

Imperial Oil did not make any of its employees available for possible employment with the Partnership following the completion of the acquisition. In connection with the purchase, the Partnership entered into a two-year transitional services agreement with Imperial Oil whereby Imperial Oil provides necessary services to operate the initiating pump station and the control center and software that control movements through the MAPL pipeline. The Partnership has the right to cancel the transitional services agreement at any time. The Partnership expects to assume all MAPL pipeline operations and transfer MAPL operations to the Partnership s Rangeland control center after its initiation facilities in Edmonton are constructed and operational.

The existing accounting software or computer hardware was not included with the assets purchased by the Partnership. The task of volumetric and revenue accounting has been consolidated with the accounting process for the Rangeland Pipeline system. The Partnership uses its existing financial accounting software for other accounting functions.

The acquisition of MAPL was accounted for as an acquisition of assets. Following the acquisition, the MAPL pipeline assets were integrated into and will be operated as part of the Rangeland Pipeline system.

Purchase Price Allocations

The acquisitions of Rangeland and MAPL have been accounted for by the purchase method of accounting pursuant to Statement of Financial Accounting Standards (FAS) No. 141, Business Combinations and, accordingly the consolidated statements of income include the results of Rangeland and MAPL from their acquisition dates. Based upon independent appraisals of the fair values of the acquired assets, the Partnership is completing its review and determination of the fair values of the assets acquired and liabilities assumed. Accordingly, the allocation of the purchase price is subject to revision. Based upon the preliminary estimates, the purchase price is being allocated to depreciable pipelines and related equipment, crude oil inventory, pipeline linefill, and rights of way, as well as to amortizable intangible assets. In addition to the cash purchase price and related acquisition costs, the Partnership assumed an environmental liability of approximately $2.2 million, and pursuant to FAS 109, *Accounting for Income Taxes* the Partnership recorded a deferred tax liability of approximately $33.9 million, representing the tax effect of the difference between the amounts paid for shares of RPC, RMC and APC, and the underlying tax basis of the assets.

3. LONG-TERM DEBT

The Partnership s long-term debt obligations at September 30, 2004 and December 31, 2003 are shown below:

	September 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
Senior secured U.S. revolving credit facility	$ 38,000	$ 73,000
Senior secured Canadian revolving credit facility	51,392	
Senior notes, net of unamortized discount of $4,278	248,655	
Senior secured term loan		225,000
Future payment for MAPL assets	3,446	
Total	341,493	298,000
Less current portion		
Long-term debt	$ 341,493	$ 298,000

Senior Secured U.S. Revolving Credit Facility and Term Loan

The revolving credit facility is a $200.0 million facility which matures on July 26, 2007 and is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders, and to finance future acquisitions. Borrowings under the revolving

credit facility are limited by various financial covenants in the credit agreement. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders.

The revolving credit facility bears interest at the Partnership s option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins are subject to change based on the credit rating of the revolving credit facility or, if is not rated, the credit rating of the Partnership s U.S. operating subsidiary, Pacific Energy Group LLC. The Partnership incurs a commitment fee which ranges from 0.125% to 0.375% per annum on the unused portion of the revolving credit facility.

As of September 30, 2004, $38.0 million was outstanding under the revolving credit facility and $111 million of undrawn credit was available under the credit facility.

On June 16, 2004, the Partnership repaid all amounts outstanding under the term loan. Amounts under the term loan that have been repaid may not be re-borrowed.

Canadian Revolving Credit Facility

On May 11, 2004, Rangeland Pipeline Company, a Canadian subsidiary of the Partnership, entered into a Canadian revolving credit facility agreement which is guaranteed by certain Canadian subsidiaries of the Partnership. The maximum amount available under the Canadian revolving credit facility is Cdn$75 million, which will be further increased to Cdn$100 million after certain other conditions are satisfied. The Canadian revolving credit facility is secured by liens on all of the property and assets of the Partnership s Canadian subsidiaries.

Indebtedness under the Canadian revolving credit facility bears interest, at Rangeland Pipeline Company s option, at either (i) the Canadian prime rate or the U.S. base rate (each plus an applicable margin ranging from 1.00% to 1.625%, or (ii) Bankers Acceptance discount rates, or LIBOR plus an applicable margin ranging from 2.00% to 2.65%. The applicable margins are subject to change based on certain financial ratios.

The Canadian revolving credit facility matures on May 11, 2007. Amounts outstanding under the credit facility may be repaid at any time prior to maturity.

The Canadian revolving credit facility is available for general corporate purposes and also provides for the issuance of letters of credit. Borrowings under this facility are limited by various financial covenants that are set forth in the Canadian credit agreement. As of September 30, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian agreement. At September 30, 2004, borrowings totaling Cdn$65.0 million (U.S.$51.4 million) and letters of credit totaling Cdn$5.0 million (U.S.$4.0 million) were outstanding under the Canadian revolving credit facility. As of September 30, 2004, the Partnership had available but undrawn credit of Cdn$5.0 million (U.S.$4.0 million) under its Canadian revolving credit facility.

Rangeland Pipeline Company incurs a commitment or standby fee which ranges from 25% to 35% of the applicable margin, based on the unused portion of the Canadian revolving credit facility. Under the Canadian credit agreement, Rangeland Pipeline Company is prohibited from declaring dividends or making any other distributions or payments to its parent or its affiliates if any default or event of default, as defined in the Canadian credit agreement, occurs or would result from such declaration or payment, or if a material adverse effect, as defined in the Canadian credit agreement, would result from such declaration or payment, or if the distributions and payments would exceed certain limits. The Canadian credit agreement also contains covenants requiring Rangeland Pipeline Company, including its subsidiaries and affiliates, to maintain specified financial ratios. In addition, the Canadian credit agreement contains other restrictive covenants. As of September 30, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian credit agreement.

7.125% Senior Notes

On June 16, 2004, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $250 million of 7.125% senior notes due June 15, 2014 (the Senior Notes). The Senior Notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 (the Securities Act) and to non-U.S. persons under Regulation S under the Securities Act. The Senior Notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Interest payments are due on June 15 and December 15 of each year, beginning on December 15, 2004. At any time prior to June 15, 2007, the Partnership has the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 107.125% of the principal amount with the net cash proceeds of one or more equity offerings. The Partnership has the option to redeem the Senior Notes, in whole or in part, at anytime on or after

June 15, 2009 at the following redemption prices:

Year		Percentage	
2009		103.563	%
2010		102.375	%
2011		101.188	%
2012 and thereafter		100.000	%

The Senior Notes are jointly and severally guaranteed by certain of the Partnership s subsidiaries, including Pacific Energy Group LLC, Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, PEG Canada GP LLC and PEG Canada, L.P.

In addition, the indenture governing the Senior Notes contains certain covenants that, among other things, limit the Partnership s ability and the ability of its restricted subsidiaries to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase Partnership units; consolidate, merge or transfer all or substantially all of its assets. At September 30, 2004, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the Senior Notes were $241.1 million after deducting the $4.4 million discount and offering expenses of $4.5 million. The net proceeds were used principally to repay the Partnership s $225 million term loan and to repay $14 million of indebtedness outstanding under the Partnership s U.S. revolving credit facility.

On September 2, 2004, the Partnership filed a Registration Statement on Form S-4 to register the Senior Notes. On September 23, 2004, the Partnership commenced an exchange offer, which allowed the holders of the Senior Notes to exchange Senior Notes for new notes with materially identical terms that have been registered under the Securities Act (the New Notes). The exchange offer expired on October 29, 2004, and all Senior Notes were exchanged for New Notes. The New Notes are not listed on any securities exchange.

Future Payment for MAPL Assets

In connection with the purchase of the MAPL pipeline, the Partnership is obligated to pay the seller Cdn$5.0 million (U.S.$4.0 million) on June 30, 2007. The future payment was discounted at 5%. The carrying value of the future payment was Cdn$4.4 million (U.S.$3.4 million) at September 30, 2004.

4. WRITE OFF OF DEFERRED FINANCING COSTS AND INTEREST RATE SWAP TERMINATION EXPENSE

On June 16, 2004, in connection with the repayment of its term loan, the Partnership had a $2.3 million non-cash write-down of deferred financing costs and incurred a $0.6 million cash expense to terminate related interest rate swaps.

5. PARTNERS CAPITAL

On March 30, 2004, the Partnership issued and sold 4,200,000 common units in an underwritten public offering at a price of $28.50. The common units sold in the offering were registered pursuant to the registration statement on SEC Form S-3 filed on August 1, 2003. Net proceeds from the offering, including the Partnership s general partner s contribution of $2.4 million, totaled approximately $116.7 million after deducting underwriting fees and offering expenses of $5.4 million. The Partnership repaid approximately $10 million in borrowings under its U.S. revolving credit facilities, which were incurred in the first quarter of 2004 to fund the deposit on the Rangeland acquisition, and used approximately $76 million of the net proceeds to fund a portion of the aggregate purchase price of the Rangeland and Mid Alberta pipeline acquisitions. The Partnership utilized the remaining $31 million in net proceeds to repay borrowings under its U.S. revolving credit facility.

On April 12, 2004, the underwriters exercised a portion of the over-allotment option granted in connection with the offering of common units on March 30, 2004 and purchased an additional 425,000 common units from the Partnership at a price of $28.50 per unit to cover over

allotments. Including the related capital contribution of the General Partner of $247,000, the Partnership received net proceeds of $11.8 million after underwriting fees. The Partnership used the $12 million in net proceeds from the exercise of the overallotment option to reduce the balance outstanding under its U.S. revolving credit facility.

6. RELATED PARTY TRANSACTIONS

In the ordinary course of its operations, the Partnership engages in various transactions with The Anschutz Corporation (TAC), the parent company of the Partnership s general partner, and TAC s affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the three and nine months ended September 30, 2004 and 2003:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Pipeline transportation revenue:				
The Anschutz Corporation and affiliates	$ 342	$ 270	$ 1,003	$ 934
General and administrative expense:				
The Anschutz Corporation and affiliates	$ 54	$ 68	$ 325	$ 246

Related party balances at September 30, 2004 and December 31, 2003 were as follows:

	September 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
Amounts included in accounts receivable:		
The Anschutz Corporation and affiliates	$ 103	$ 155
Frontier Pipeline Company	$ 264	64
Amounts included in due to related parties:		
Pacific Energy GP, Inc.	$ 374	$ 580

Revenue from Related Parties

A subsidiary of TAC was a shipper on the Partnership s Line 2000 and was charged the published tariff rates applicable to participating shippers until March 31, 2003, when an agreement between the TAC subsidiary and a third party, the performance of which required the TAC subsidiary to ship on Line 2000, was assigned to the Partnership for consideration equal to the value of transferred inventory. In addition, a subsidiary of TAC is a shipper on pipelines owned by Rocky Mountain Pipeline LLC (RMPS) a subsidiary of the Partnership, and is charged published tariff rates.

RMPS serves as the contract operator for certain gas producing properties owned by a subsidiary of TAC in Wyoming and Utah, in exchange for which RMPS is reimbursed its direct costs of operation and is paid an annual fee of $0.3 million as compensation for the time spent by RMPS management and for other overhead services related to their activities. In addition, during 2003 and the first quarter of 2004, RMPS s trucking operation hauled water for a TAC subsidiary at rates equivalent to those charged to third parties.

RMPS also receives a management fee from Frontier Pipeline Company (Frontier) in connection with time spent by RMPS management and for other services related to Frontier s pipeline s activities. RMPS received $0.3 million and $0.1 million for the three months ended September 30, 2004 and 2003 and $0.6 million and $0.4 million for the nine months ended September 30, 2004 and 2003, respectively.

Expenses Paid to Related Parties

General and Administrative Expense: In 2002, the Partnership began utilizing the financial accounting system owned and provided by TAC under a shared services arrangement. In addition, the Partnership from time to time utilized the services of TAC s risk management personnel for acquiring the Partnership s insurance, and the Partnership s surety bonds are issued under TAC s bonding line. Beginning January 2003, TAC began charging the Partnership a fee of $0.1 million per year for these services and continues to charge the Partnership for any out-of-pocket costs it incurs. The fixed annual fee includes all license, maintenance and employee costs associated with the Partnership s use of the financial accounting system.

Beginning January 2003, and as amended in May 2004, the Partnership leases approximately 5,400 square feet of office space from an affiliate of TAC, for a term of five years at an annual cost of $0.1 million.

Cost Reimbursements: The Partnership s general partner, Pacific Energy GP, Inc. (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.

The operating and general and administrative cost reimbursement amounts above exclude reimbursements for property, casualty and directors and officers insurance premiums paid by TAC on behalf of the Partnership, until mid-2003. Beginning with the 2003-2004 insurance policy period, the Partnership incurred these costs directly. In addition, out-of-pocket costs incurred by TAC for the benefit of the Partnership for computer consultants and surety bonds are also reimbursed by the Partnership.

Other: The Partnership also reimburses TAC for transportation services, based on a cost-based formula. For the nine months ended September 30, 2004, the Partnership reimbursed TAC $0.1 million. An insignificant amount was incurred for the nine months ended September 30, 2003.

7. SEGMENT INFORMATION

The Partnership s business and operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations. The West Coast operations include: (i) Pacific Pipeline System LLC, owner of Line 2000 and Line 63, (ii) Pacific Marketing and Transportation LLC, owner of the PMT gathering and blending system, and (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system (for the period from July 31, 2003 to September 30, 2004). Rocky Mountain operations include: (i) Rocky Mountain Pipeline System LLC, (ii) Ranch Pipeline LLC, and (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate all of the Partnership s Canadian assets (for the period from May 11, 2004 to September 30, 2004). The reporting units comprising each segment have been aggregated to reflect how the assets are operated and managed. General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and marketing and business development, are not allocated to the individual segments. Information regarding these two operating units is summarized below:

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
	(in thousands) (unaudited)			
Three months ended September 30, 2004				
Segment revenue:				
Pipeline transportation revenue	$ 16,985	$ 12,500	$ (1,325)	$ 28,160
Storage and distribution revenue(1)	8,544		(153)	8,391
Pipeline buy/sell transportation revenue(2)		7,972		7,972
Crude oil sales, net of purchases(3)	3,568			3,568
Net revenue	29,097	20,472		48,091
Expenses:				
Operating	14,309	9,758	(1,478)	22,589
Transition costs		199		199
Depreciation and amortization	3,433	3,388		6,821
Total expenses	17,742	13,345		29,609
Share of net income of Frontier		406		406
Operating income from segments(4)	$ 11,355	$ 7,533		$ 18,888
Identifiable assets(5)	$ 507,459	$ 330,830		$ 838,289
Capital expenditures	$ 1,862	$ 1,764		$ 3,626
Three months ended September 30, 2003				
Segment revenue:				
Pipeline transportation revenue	$ 16,662	$ 11,006	$ (2,167)	$ 25,501
Storage and distribution revenue(1)	4,710			4,710
Pipeline buy/sell transportation revenue(2)				
Crude oil sales, net of purchases(3)	5,907			5,907
Net revenue	27,279	11,006		36,118
Expenses:				
Operating	12,997	5,800	(2,167)	16,630
Transition costs				
Depreciation	3,529	1,520		5,049

Total expenses			16,526			7,320					21,679
Share of net income of Frontier						414					414
Operating income from segments(4)		$	10,753		$	4,100				$	14,853
Identifiable assets(5)		$	499,127		$	124,473				$	623,600
Capital expenditures		$	763		$	366				$	1,129

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
		(in thousands) (unaudited)		
Nine months ended September 30, 2004				
Segment revenue:				
Pipeline transportation revenue	$ 49,170	$ 34,847	$ (4,138)	$ 79,879
Storage and distribution revenue(1)	28,126		(353)	27,773
Pipeline buy/sell transportation revenue(2)		11,662		11,662
Crude oil sales, net of purchases(3)	14,436			14,436
Net revenue	91,732	46,509		133,750
Expenses:				
Operating	43,197	23,483	(4,491)	62,189
Transition costs		383		383
Depreciation and amortization	10,833	6,943		17,776
Total expenses	54,030	30,809		80,348
Share of net income of Frontier		1,190		1,190
Operating income from segments(4)	$ 37,702	$ 16,890		$ 54,592
Identifiable assets(5)	$ 507,459	$ 330,830		$ 838,289
Capital expenditures	$ 5,279	$ 6,243		$ 11,522
Nine months ended September 30, 2003				
Segment revenue:				
Pipeline transportation revenue	$ 51,550	$ 30,726	$ (5,697)	$ 76,579
Storage and distribution revenue(1)	4,710			4,710
Pipeline buy/sell transportation revenue(2)				
Crude oil sales, net of purchases(3)	16,516			16,516
Net revenue	72,776	30,726		97,805
Expenses:				
Operating	32,793	16,526	(5,697)	43,622
Transition costs		397		397
Depreciation	9,210	4,225		13,435
Total expenses	42,003	21,148		57,454
Share of net income of Frontier		1,141		1,141
Operating income from segments(4)	$ 30,773	$ 10,719		$ 41,492
Identifiable assets(5)	$ 499,127	$ 124,473		$ 623,600
Capital expenditures	$ 1,480	$ 840		$ 2,320

(1) Includes the revenue of the Pacific Terminals storage and distribution system, which Pacific Terminals acquired on July 31, 2003.

(2) Includes the revenue of the Canadian subsidiaries, which were acquired on May 11, 2004.

(3) The above amounts are net of purchases of $103,192 and $96,833 for the three months ended September 30, 2004 and 2003 and $278,689 and $271,554 for the nine months ended September 30, 2004, respectively.

(4) The following is a reconciliation of operating income as stated above to the statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Income Statement Reconciliation				
Operating income from segments above:				
West Coast Operations	$ 11,355	$ 10,753	$ 37,702	$ 30,773
Rocky Mountain Operations	7,533	4,100	16,890	10,719
Operating income from segments	18,888	14,853	54,592	41,492
Less: General and administrative expense	3,762	3,305	11,252	10,289
Operating income	15,126	11,548	43,340	31,203
Interest expense	(5,234)	(4,782)	(13,743)	(12,930)
Write-off of deferred financing cost and interest rate swap termination expense			(2,901)	
Other income	219	113	606	360
Income before income taxes	10,111	6,879	27,302	18,633
Income tax expense	221		207	
Net income	$ 9,890	$ 6,879	$ 27,095	$ 18,633

(5) Identifiable segment assets do not include assets related to the Partnership s corporate activity. As of September 30, 2004 and 2003, corporate related assets were $29,651 and $21,093, respectively.

8. COMMITMENTS AND CONTINGENCIES

The Partnership is subject to numerous federal (U.S. and Canadian), state, provincial and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. At September 30, 2004, the Partnership had accrued for future environmental remediation liabilities of $7.5 million, including a current portion of $1.3 million, and right-of-way liabilities of $1.0 million, resulting from various acquisitions, which liabilities are classified in the accompanying condensed consolidated balance sheets within other liabilities. The actual future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership s liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other potentially responsible parties.

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

9. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Given that certain, but not all subsidiaries are guarantors of our 7.125% Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, Pacific Energy Partners, L.P. and its predecessor are referred to as Parent. Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Ranch Pipeline LLC, PEG Canada GP LLC, PEG Canada, L.P. and Pacific Energy Group LLC are collectively referred to as the Guarantor Subsidiaries and Pacific Pipeline System LLC and Pacific Terminals LLC are referred to as Non-Guarantor Subsidiaries.

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, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
	(unaudited)				
Assets:					
Current assets	$ 10,863	$ 89,944	$ 33,445	$ (36,275)	$ 97,977
Property and equipment		129,218	584,133		713,351
Equity investments	375,701	195,624		(563,484)	7,841
Intercompany notes receivable	292,487	335,861		(628,348)	
Other assets	7,529	2,164	39,078		48,771
Total assets	$ 686,580	$ 752,811	$ 656,656	$ (1,228,107)	$ 867,940
Liabilities and partners capital:					
Current liabilities	$ 16,315	$ 46,201	$ 34,770	$ (36,275)	$ 61,011
Long-term debt	248,655	38,000	54,838		341,493
Deferred income taxes			36,641		36,641
Intercompany notes payable		292,487	335,861	(628,348)	
Other liabilities		422	6,763		7,185
Total partners capital	421,610	375,701	187,783	(563,484)	421,610
Total liabilities and partners capital	$ 686,580	$ 752,811	$ 656,656	$ (1,228,107)	$ 867,940

	Balance Sheet December 31, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
	(unaudited)				
Assets:					
Current assets	$ 2,799	$ 63,905	$ 17,168	$ (15,076)	$ 68,796

Property and equipment				126,216		441,738						567,954
Equity investments		292,268		165,815				(451,197)				6,886
Intercompany notes receivable				276,400				(276,400)				
Other assets				4,957		1,610						6,567
Total assets	$	295,067	$	637,293	$	460,516	$	(742,673)		$		650,203
Liabilities and partners capital:												
Current liabilities	$		$	45,980	$	19,087	$	(15,076)		$		49,991
Long-term debt				298,000								298,000
Intercompany notes payable						276,400		(276,400)				
Other liabilities				1,045		6,100						7,145
Total partners capital		295,067		292,268		158,929		(451,197)				295,067
Total liabilities and partners capital	$	295,067	$	637,293	$	460,516	$	(742,673)		$		650,203

	Statement of Income Three Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Operating revenues	$	$ 16,068	$ 33,501	$ (1,478)	$ 48,091
Operating expenses		(10,190)	(14,076)	1,478	(22,788)
General and administrative expense(1)		(3,311)	(451)		(3,762)
Depreciation and amortization expense		(1,668)	(5,153)		(6,821)
Share of net income of Frontier		406			406
Operating income		1,305	13,821		15,126
Interest expense	(3,894)	(489)	(851)		(5,234)
Intercompany interest income (expense)		5,946	(5,946)		
Equity earnings	13,798	7,158		(20,956)	
Interest and other income (expense)	(14)	151	82		219
Income tax benefit (expense)		(273)	52		(221)
Net income	$ 9,890	$ 13,798	$ 7,158	$ (20,956)	$ 9,890

(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, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Operating revenues	$	$ 16,914	$ 21,371	$ (2,167)	$ 36,118
Operating expenses and transition costs		(10,252)	(8,545)	2,167	(16,630)
General and administrative expense(1)	6	(3,288)	(23)		(3,305)
Depreciation and amortization expense		(1,643)	(3,406)		(5,049)
Share of net income of Frontier		414			414
Operating income	6	2,145	9,397		11,548
Interest expense		(4,782)			(4,782)
Intercompany interest income (expense)		2,876	(2,876)		
Equity earnings	6,869	6,526		(13,395)	
Interest and other income	4	104	5		113
Net income	$ 6,879	$ 6,869	$ 6,526	$ (13,395)	$ 6,879

(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, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Operating revenues	$	$ 49,283	$ 88,958	$ (4,491)	$ 133,750
Operating expenses and transition costs		(29,928)	(37,135)	4,491	(62,572)
General and administrative expense(1)		(10,529)	(723)		(11,252)
Depreciation and amortization expense		(4,911)	(12,865)		(17,776)
Share of net income of Frontier		1,190			1,190
Operating income		5,105	38,235		43,340
Interest expense	(4,648)	(7,909)	(1,186)		(13,743)
Write-off of deferred financing cost and interest rate swap termination expense		(2,901)			(2,901)
Intercompany interest income (expense)		14,564	(14,564)		
Equity earnings	31,752	22,732		(54,484)	
Interest and other income (expense)	(9)	434	181		606
Income tax benefit (expense)		(273)	66		(207)
Net income	$ 27,095	$ 31,752	$ 22,732	$ (54,484)	$ 27,095

(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, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Operating revenues	$	$ 47,243	$ 56,259	$ (5,697)	$ 97,805
Operating expenses and transition costs		(29,436)	(20,280)	5,697	(44,019)
General and administrative expense(1)		(10,215)	(74)		(10,289)
Depreciation and amortization expense		(4,549)	(8,886)		(13,435)
Share of net income of Frontier		1,141			1,141

Operating income		4,184	27,019		31,203
Interest expense		(12,930)			(12,930)
Intercompany interest income (expense)		6,484	(6,484)		
Equity earnings	18,616	20,573		(39,189)	
Interest and other income	17	305	38		360
Net income	$ 18,633	$ 18,616	$ 20,573	$ (39,189)	$ 18,633

(1) General and administrative expense is not currently allocated between guarantor and non-guarantor subsidiaries for financial reporting purposes.

	Statement of Comprehensive Income Three Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Net income	$ 9,890	$ 13,798	$ 7,158	$ (20,956)	$ 9,890
Change in fair value of hedging derivatives	(1,107)	(1,107)		1,107	(1,107)
Foreign currency translation adjustment	5,313	5,313	5,313	(10,626)	5,313
Comprehensive income	$ 14,096	$ 18,004	$ 12,471	$ (30,475)	$ 14,096

	Statement of Comprehensive Income ThreeMonths Ended September 30, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Net income	$ 6,879	$ 6,869	$ 6,526	$ (13,395)	$ 6,879
Change in fair value of hedging derivatives	4,143	4,143		(4,143)	4,143
Comprehensive income	$ 11,022	$ 11,012	$ 6,526	$ (17,538)	$ 11,022

	Statement of Comprehensive Income Nine Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Net income	$ 27,095	$ 31,752	$ 22,732	$ (54,484)	$ 27,095
Change in fair value of hedging derivatives	3,797	3,797		(3,797)	3,797
Foreign currency translation adjustment	7,742	7,742	7,742	(15,484)	7,742
Comprehensive income	$ 38,634	$ 43,291	$ 30,474	$ (73,765)	$ 38,634

	Statement of Comprehensive Income Nine Months Ended September 30, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
Net income	$ 18,633	$ 18,616	$ 20,573	$ (39,189)	$ 18,633
Change in fair value of hedging derivatives	(845)	(845)		845	(845)
Comprehensive income	$ 17,788	$ 17,771	$ 20,573	$ (38,344)	$ 17,788

	Statement of Cash Flows Nine Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 27,095	$ 31,752	$ 22,732	$ (54,484)	$ 27,095
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(31,752)	(22,732)		54,484	
Distributions from subsidiaries	41,800	35,012		(76,812)	
Depreciation, amortization and other	176	8,127	12,837		21,140
Net changes in operating assets and liabilities	4,550	(10,783)	(6,893)	6,905	(6,221)
NET CASH PROVIDED BY OPERATING ACTIVITIES	41,869	41,376	28,676	(69,907)	42,014
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(139,000)		(139,000)
Additions to property and equipment and other		(7,633)	(4,510)		(12,143)
Intercompany	(369,675)	(96,267)		465,942	
NET CASH USED IN INVESTING ACTIVITIES	(369,675)	(103,900)	(143,510)	465,942	(151,143)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	328,210	63,622	118,161	(396,035)	113,958
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	404	1,098	3,327		4,829
CASH AND CASH EQUIVALENTS, beginning of reporting period	746	8,603	350		9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 1,150	$ 9,701	$ 3,677	$	$ 14,528

	Statement of Cash Flows Nine Months Ended September 30, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands) (unaudited)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 18,633	$ 18,616	$ 20,573	$ (39,189)	$ 18,633
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(18,616)	(20,573)		39,189	
Distributions from subsidiaries	29,657	28,177		(57,834)	
Depreciation, amortization and other		7,885	8,886		16,771
Net changes in operating assets and liabilities	42	1,457	3,911	(7,413)	(2,003)
NET CASH PROVIDED BY OPERATING ACTIVITIES	29,716	35,562	33,370	(65,247)	33,401
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(159,939)		(159,939)
Additions to property, equipment and other		(948)	(1,235)		(2,183)
Intercompany	(92,891)	(160,000)		252,891	
NET CASH USED IN INVESTING ACTIVITIES	(92,891)	160,948	(161,174)	252,891	(162,122)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	62,006	126,748	121,124	(187,644)	122,234
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,169)	1,362	(6,680)		(6,487)
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,394	13,285	8,194		23,873
CASH AND CASH EQUIVALENTS, end of reporting period	$ 1,225	$ 14,647	$ 1,514	$	$ 17,386

11. SUBSEQUENT EVENT

Cash Distribution

On October 22, 2004, the Partnership announced a cash distribution of $0.4875 per limited partner unit, payable on November 12, 2004, to unitholders of record as of November 1, 2004. On October 27, 2004, the Partnership announced that it expects, subject to final board approval, to increase its quarterly distribution rate to $0.50 per unit beginning with the fourth quarter 2004 distribution payable in February 2005.

Pending Sale of The Anschutz Corporation s Interest in the Partnership

On October 29, 2004, the Partnership announced that The Anschutz Corporation had agreed to sell its 36.7% interest in the Partnership for an undisclosed amount to LB Pacific, LP, an entity formed by Lehman Brothers Merchant Banking Group (Lehman Brothers Merchant Banking). The acquisition by Lehman Brothers Merchant Banking will include (i) a 100% ownership interest in the General Partner, which owns the 2% general partner interest in the Partnership and the incentive distribution rights and (ii) 10,465,000 subordinated units of the Partnership representing a 34.7% limited partner interest in the Partnership. The transaction is expected to close in the first quarter of 2005, subject to certain conditions, including applicable regulatory approvals and other customary closing conditions.

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 Ener 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, forecast, intend, plan, position, predict, project, or strategy or the negative connotation or other variations of su other similar terminology. In 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. For a more detailed description of these and other factors that may affect the forward-looking statements, please read Risk Factors contained in our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003, and declared effective by the Securities and Exchange Commission (SEC) on August 8, 2003, and our annual report on Form 10-K for the year ended December 31, 2003, as well as 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., the successor to Pacific Energy (Predecessor) (as defined below) 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 the unaudited condensed consolidated balance sheet, statements of income and statements of cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy Group LLC (PEG), whose subsidiaries consist of: (i) Pacific Pipeline System LLC (PPS), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC (PT), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC (PMT), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC (RMPS), owner of the Partnership s interest in various pipelines that make up the Western Corridor system, the Salt Lake City Core system, and AREPI pipeline, and (v) Ranch Pipeline LLC (RPL), the owner of a 22.22% partnership interest in Frontier Pipeline Company (Frontier).

The unaudited condensed consolidated balance sheet, statements of income and statements of cash flows of the Partnership also include our 100% ownership interest in PEG Canada GP LLC, the general partner of PEG Canada, L.P. (PEG Canada), the holding company for our Canadian subsidiaries. We own 100% of the limited partner interests in PEG Canada, whose 100% owned subsidiaries consist of (i) Rangeland Pipeline Company (RPC), which owns 100% of Aurora Pipeline Company Ltd. (APC) and a partnership interest in Rangeland Pipeline Partnership (RPP), (ii) Rangeland Northern Pipeline Company (RNPC), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company (RMC). RPP owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by APC.

We also own 100% of Pacific Energy Finance Corporation, co-issuer of our 7.125% Senior Notes.

PPS, PT and PMT comprise our West Coast operations segment. RMPS, RPL, PEG Canada, RPC, APC, RPP, RNPC and RMC comprise our Rocky Mountain operations segment. Certain costs of PEG are also included in each segment.

The financial data included herein reflects (i) the ownership and results of operations of the assets comprising the Pacific Terminals storage and distribution system for the period from July 31, 2003 to September 30, 2004; (ii) the ownership and results of operations of Rangeland Pipeline system for the period from May 11, 2004 to September 30, 2004; and (iii) the ownership of MAPL pipeline for the period June 30, 2004 to September 30, 2004.

This report on Form 10-Q should be read in conjunction with our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003, and declared effective by the Securities and Exchange Commission (SEC) on August 8, 2003, and our annual report on Form 10-K for the year ended December 31, 2003.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing and distributing crude oil and related products in California and the Rocky Mountain region, including Alberta, Canada. We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing storage capacity. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business. We operate primarily in California, Colorado, Montana, Wyoming and Utah in the United States and in Alberta, Canada, and conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations.

We are managed by our general partner, Pacific Energy GP, Inc., a wholly owned indirect subsidiary of The Anschutz Corporation.

West Coast Operations

Our West Coast operations are located in California and include the only common carrier pipelines that deliver crude oil produced in California s San Joaquin Valley and the two primary California Outer Continental Shelf (OCS) producing fields, Point Arguello and the Santa Ynez Unit, to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. In addition, we own and operate storage and distribution assets servicing the Los Angeles Basin, which we believe strategically position us to benefit from the projected increase in marine imports of crude oil into this region. Our West Coast operations are headquartered in Long Beach, California, with a field office in Bakersfield.

Our West Coast operations are comprised of the following assets, all of which we operate and own 100%:

Line 2000: Line 2000 is an intrastate common carrier crude oil pipeline that consists of a 130-mile, insulated trunk pipeline with a permitted annual throughput capacity of 130,000 barrels per day (bpd) that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin.

Line 63 System: The Line 63 system is an intrastate common carrier crude oil pipeline system that consists of a 107-mile trunk pipeline with a throughput capacity of approximately 105,000 bpd, 60 miles of distribution pipelines, 156 miles of gathering pipelines, and 22 storage tanks with a total of approximately 1.2 million barrels of storage capacity. Most of these storage assets are located in the San Joaquin Valley and are primarily used to facilitate the transportation of crude oil on our pipelines.

PMT Gathering and Blending System: The PMT gathering and blending system is a proprietary crude oil pipeline system located in the San Joaquin Valley that consists of 103 miles of gathering pipelines and five storage and blending facilities with a total of approximately 0.25 million barrels of storage capacity and up to 51,000 bpd of blending capacity. The PMT gathering and blending system is interconnected to our Line 63 system. PMT buys, blends and sells crude oil, activities that are complementary to our pipeline transportation business.

Pacific Terminals Storage and Distribution System: The Pacific Terminals storage and distribution system is a storage and pipeline distribution system located in the Los Angeles Basin that consists of 70 miles of distribution pipelines in active service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total approximately 6.7 million barrels are in active commercial service, 0.5 million barrels are used primarily for throughput to other storage tanks and do not generate revenue independently, approximately 1.5 million barrels are idle but could be reconditioned and brought into service, and approximately 0.3 million barrels are in displacement oil service.

Rocky Mountain Operations

Our Rocky Mountain operations consist of various interests in pipelines that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in the states of Montana, Wyoming, Colorado and Utah, and in Canada. We deliver crude oil to these refineries directly through our pipelines or indirectly through connections with third-party pipelines. Our Rocky Mountain operations are headquartered in Denver, Colorado and Calgary, Alberta. We have five field offices in Wyoming and two in Alberta.

Our Rocky Mountain operations are comprised of the following assets, which form an integrated pipeline network:

Rangeland Pipeline System: The Rangeland Pipeline system includes Rangeland pipeline and Mid Alberta Pipeline (MAPL). The MAPL pipeline is a 138-mile proprietary pipeline with a throughput capacity of approximately 50,000 bpd if transporting light crude oil. MAPL pipeline originates at Edmonton, Alberta and terminates in Sundre, Alberta, where it connects to the Rangeland Pipeline system. The Rangeland Pipeline system is a proprietary pipeline system that consists of approximately 800 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S.-Canadian border near Cutbank, Montana, where it connects to the Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S.-Canadian border consists of approximately 250 miles of trunk pipelines and has a current throughput capacity of approximately 85,000 bpd if transporting light crude oil. In 2003, approximately 47,000 barrels per day were transported on the trunk pipeline. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines for low sulfur crude oil, high sulfur crude oil, and for condensate and butane, each approximately 60 miles in length.

Over the next year, we will construct a new initiating terminal facility with multiple pipeline connections in Edmonton, Alberta. In the interim, current volumes of approximately 5,000 bpd are expected to continue being transported on MAPL pipeline. The Rangeland Pipeline system will transport these volumes plus its own current volumes of approximately 40,000 bpd for a total volume of 45,000 bpd south to the United States. In addition, approximately 20,000 bpd will continue to be gathered and transported north to Edmonton, Alberta.

Western Corridor System: The Western Corridor system is an interstate and intrastate common carrier crude oil pipeline system that consists of 1,012 miles of pipelines extending from dual origination points at the U.S.-Canadian border near Cutbank, Montana, where it receives deliveries from the Rangeland system, and at Cutbank, Montana, where it receives deliveries from Cenex pipeline, and terminating at Guernsey, Wyoming with connections in Wyoming to Frontier pipeline, Suncor s pipeline, Platte pipeline and the Salt Lake City Core system. The Western Corridor system consists of three contiguous trunk pipelines: Glacier pipeline, Beartooth pipeline and Big Horn pipeline. We own various undivided interests in each of these three pipelines, which give us rights to a specified portion of each pipeline s throughput capacity. Glacier and Beartooth pipelines provide us with approximately 25,000 bpd of throughput capacity from the U.S.-Canadian border to Elk Basin, Wyoming. Big Horn pipeline provides us with approximately 33,900 bpd of throughput capacity from Elk Basin, Wyoming to Guernsey, Wyoming. We operate Beartooth and Big Horn pipelines. Conoco Pipe Line Company owns the remaining undivided interests in each pipeline and operates Glacier pipeline. We also own various undivided interests in 22 storage tanks that provide us with a total of approximately 1.3 million barrels of storage capacity.

Salt Lake City Core System: The Salt Lake City Core system is an interstate and intrastate common carrier crude oil pipeline system that consists of 914 miles of trunk pipelines with a combined throughput capacity of approximately 60,000 bpd to Salt Lake City, 209 miles of gathering pipelines, and 30 storage tanks with a total of approximately 1.5 million barrels of storage capacity. This system originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming, and terminates in Salt Lake City and in Rangely, Colorado. The Rangely terminus delivers to a ChevronTexaco pipeline that serves refineries in Salt Lake City. Of the 60,000 bpd

delivery capacity into Salt Lake City, approximately 40,000 bpd is delivered directly through our pipelines and approximately 20,000 bpd is delivered indirectly through a connection to a ChevronTexaco pipeline. Since completion of a new connection in July 2004, the Salt Lake City Core system also receives deliveries from Frontier pipeline at Frontier Station, Wyoming. We operate and own 100% of the Salt Lake City Core system.

AREPI Pipeline: AREPI pipeline is an interstate common carrier crude oil pipeline that consists of a 42-mile trunk pipeline with a throughput capacity of approximately 52,500 bpd and three storage tanks with a total of approximately 0.1 million barrels of storage capacity. AREPI pipeline originates at Ranch Station, Utah, where it receives deliveries from Frontier pipeline, and terminates in Kimball Junction, Utah, where it delivers to a ChevronTexaco pipeline that serves

refineries in Salt Lake City. We own and operate 100% of AREPI pipeline.

Frontier Pipeline: Frontier pipeline is an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd and three storage tanks with a total of approximately 274,000 barrels of storage capacity. Frontier pipeline originates in Casper, Wyoming, receives deliveries from the Western Corridor system and terminates south of Evanston, Wyoming at Ranch Station, Utah. Frontier pipeline delivers crude oil to AREPI pipeline and to the Salt Lake City Core system for ultimate delivery to Salt Lake City. We operate Frontier pipeline and own a 22.22% partnership interest in Frontier Pipeline Company, the general partnership that owns Frontier pipeline. Enbridge, Inc. owns the remaining partnership interest in Frontier Pipeline Company.

Recent Developments

Pending Sale of The Anschutz Corporation s Interest in the Partnership

On October 29, 2004, the Partnership announced that TAC had agreed to sell its 36.7% interest in the Partnership for an undisclosed amount to LB Pacific, LP, an entity formed by Lehman Brothers Merchant Banking Group (Lehman Brothers Merchant Banking). The acquisition by Lehman Brothers Merchant Banking will include (i) a 100% ownership interest in the General Partner, which owns the 2% general partner interest in the Partnership and the incentive distribution rights and (ii) 10,465,000 subordinated units of the Partnership representing a 34.7% limited partner interest in the Partnership. The transaction is expected to close in the first quarter of 2005 and is subject to certain conditions, including applicable regulatory approvals and other customary closing conditions.

Canadian Acquisitions

Rangeland Pipeline System Acquisition. On May 11, 2004, we completed the acquisition of the Rangeland Pipeline system from BP Canada Energy Company (BP). The Rangeland Pipeline system is located in Alberta, Canada. The purchase price for the Rangeland Pipeline system was Cdn$130 million plus approximately Cdn$29 million for linefill, working capital, transaction costs and transition capital expenditures for an aggregate purchase price of Cdn$159 million or US$116 million.

MAPL Pipeline Acquisition. On June 30, 2004, we completed the acquisition of MAPL pipeline, located in Alberta, Canada from Imperial Oil. The purchase price for MAPL was Cdn$31.5 million, of which Cdn$5.0 million is payable on June 30, 2007. In addition, we acquired linefill for Cdn$5.0 million. The aggregate purchase price including linefill, first year construction costs and transaction costs is approximately US$30 million and was funded principally from our Canadian credit facilities.

Integration and Transition. The Rangeland Pipeline system and MAPL pipeline have each historically been operated on a proprietary basis. MAPL pipeline has, since its purchase, been integrated into the Rangeland Pipeline system, and we intend to make significant changes to the revenue-generating capability of these assets by combining and integrating fully all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, by expanding the throughput capacity of the Rangeland Pipeline system by establishing connections with other pipelines, and by constructing a pump station and receiving terminal in Edmonton, Alberta. This new pump station and receiving terminal will be able to access multiple sources of Canadian crude oil, which will allow us to participate in the projected increase in production of synthetic crude oil. The construction of the new connections on the Rangeland Pipeline system and the new pump station and receiving terminal is expected to cost approximately Cdn$6.5 million, and is expected to be completed in the third quarter of 2005.

Financing. We funded the aggregate purchase price, including transaction costs, for the Rangeland Pipeline system and MAPL pipeline with a portion of the net proceeds from our March 2004 issuance of common units and Cdn$65 million in borrowings under our new Cdn$100 million revolving credit facility.

Pier 400

In February 2004, we completed a feasibility study for the development of 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. We are continuing with the next phase of development of the Pier 400 terminal, commencing with the environmental review, which is expected to be completed by late 2005. In connection with this next phase of development, we entered into a project development agreement with two subsidiaries of Valero Energy Corporation (Valero) that defines the

facilities that we are to construct in the POLA, and a terminalling services agreement that defines the ongoing commercial arrangement including a 30-year, 50,000 bpd volume commitment from Valero to support the terminal. Each of these agreements is subject to the satisfaction of various conditions, including completion of a mutually satisfactory vessel emissions allocation agreement. In addition, we and the POLA have identified several possible sites for construction of storage facilities and have begun the review process required by the California Environmental Quality Act.

If the Pier 400 terminal receives the necessary governmental approvals and is successfully developed, a deepwater berth, transfer infrastructure and storage tanks will be constructed at Pier 400 and Terminal Island in the POLA and a pipeline distribution system will be constructed to connect the terminal s storage tanks to Valero s Wilmington refinery and to our other customers facilities in the Los Angeles Basin through our Pacific Terminals storage and distribution system. We would construct the transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels, storage tanks with an initial storage capacity of approximately 1.5 million barrels, and a pipeline distribution system, all at an estimated cost of approximately $130 million. The deepwater berth at Pier 400 would be constructed by the POLA. The ultimate cost of the project will depend on its scope, which may increase depending on the level of customer commitments, as well as on permit requirements.

The Pier 400 terminal would provide marine receipt facilities with water depth of approximately 81 feet, capable of handling some of the largest tankers, and with the capacity to efficiently accommodate increasing volumes of waterborne imported crude oil and refinery feedstocks. Initially, the Pier 400 terminal is expected to handle marine receipts of approximately 100,000 bpd. However, the receipt facilities are being designed, subject to permit limitations, to accommodate up to approximately 250,000 bpd. We expect construction of the Pier 400 terminal to be completed and placed in service in early 2007.

We spent approximately $5.3 million on the Pier 400 terminal beginning in the second quarter of 2003 through the end of 2003 and $2.5 million in 2004 through September 30, 2004. We expect to incur additional capital expenditures of approximately $0.4 million during the remainder of 2004. We anticipate funding pre-construction costs through late-2005 from a portion of the proceeds from our March 2004 issuance of common units. Construction of the Pier 400 terminal is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Salt Lake City Expansion Project

We also recently expanded our pipelines serving Salt Lake City by establishing a new delivery connection from Frontier pipeline to the Salt Lake City Core system at a cost of approximately $3 million. Existing pipelines into Salt Lake City were previously prorated, or limited by capacity, during the summer season. This connection increases delivery capacity to Salt Lake City refineries by approximately 8,000 to 9,000 bpd.

Equity and Debt Offerings

On March 30, 2004, we issued and sold 4,200,000 common units in an underwritten public offering at a price of $28.50 per common unit before underwriting fees and offering expenses. On April 12, 2004, the underwriters exercised a portion of the over-allotment option and purchased an additional 425,000 common units to cover over-allotments at a price of $28.50 per common unit before underwriting fees and offering expenses. Net proceeds received from the offering, including the general partner s contribution of $2.7 million, totaled approximately $128.5 million after deducting underwriting fees and offering expenses. We used $86 million of the net proceeds to finance the acquisition of the Rangeland system and the balance of the net proceeds to repay borrowings outstanding under our U.S. revolving credit facility.

On June 16, 2004, we completed the sale of $250 million of 7.125% Senior Notes due June 15, 2014 (the Senior Notes). The Senior Notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Net proceeds from the issuance of the Notes were $241.1 million after deducting the $4.4 million discount and offering expenses of $4.5 million. The net proceeds were used principally to repay our $225 million term loan and to repay $14 million of indebtedness outstanding under our U.S. revolving credit facility.

On September 2, 2004, we filed a Registration Statement on Form S-4 to register our 7.125% Senior Notes, which were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 (the Securities Act) and to non-U.S. persons under Regulation S under the Securities Act. On September 23, 2004, we commenced an exchange offer, which allowed the holders of the Senior Notes to exchange Senior Notes for new notes with

materially identical terms that have been registered under the Securities Act (the New Notes). The exchange offer expired on October 29, 2004, and all Senior Notes were exchanged for New Notes. The New Notes are not listed on any securities exchange.

In connection with the issuance of the notes, we entered into interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The net impact of the notes offering, the related interest rate swap and the term loan repayment is that we expect our interest expense to remain largely unchanged.

Business Fundamentals

Pipeline Transportation

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

Our shippers determine the amount of crude oil we transport on our pipelines, but we 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 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, which 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 OCS, total production is generally declining. In the third quarter of 2004, producers began the development of the Rocky Point field in the California OCS with the drilling of the first of eight planned wells. The first well began production at the end of the third quarter of 2004, thereby increasing the supply of crude oil available to be transported by us into the Los Angeles Basin. We anticipate that a significant portion of the Rocky Point production will be transported on our pipelines.

In addition, Shell has announced that it has extended the operation of its Bakersfield refinery through March 31, 2005, while it explores the possible sale of the refinery. In late 2003, Shell had announced its plans to close the refinery October 1, 2004. Should Shell ultimately close the refinery, we continue to believe this would increase the supply of crude oil available to be transported by us to the Los Angeles Basin, offsetting some or all of the effects of production decline in the short-term. In the event the refinery continues operating, we believe there may be an opportunity to transport additional volumes of crude oil to the refinery.

In addition, we acquired the Pacific Terminals storage and distribution assets and are developing the Pier 400 terminal to participate in the marine import business, which is growing as a result of the local production decline. In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and we recently completed the acquisitions of pipeline systems giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any Rocky Mountain production decline and meet growing

demand in the Rocky Mountain region.

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (the 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 pipelines are regulated by either the FERC or the Wyoming Public Service Commission, generally under a cost-of-service approach.

On May 1, 2004, we increased the tariff rates on Line 2000 by approximately 6%, based on a contractually agreed index of cost changes plus a market adjustment. This index is reviewed annually. On October 1, 2004, we applied to the CPUC for a 9.5% cost of service increase of the tariff rates on our Line 63 Pipeline system. This increase, the first for Line 63 since 2001, went into effect on November 1, 2004, subject to subsequent approval by the CPUC and the obligation to refund, with interest, any portion of the tariff charged after November 1, 2004 that is subsequently disallowed by the CPUC.

Storage and Distribution

We provide storage and distribution services to refineries in the Los Angeles Basin. The fundamental items impacting our storage and distribution 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 other dark products storage capacity is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for dark products storage capacity are usually short term (less that one year). One of our business goals is to convert a number of other dark products tanks to more flexible crude oil service (which can also accommodate other dark products); we currently await permit approvals for one such tank conversion.

While PT s rates are regulated by the CPUC, the CPUC has authorized PT to establish its rates based on market conditions through negotiated contracts.

Pipeline Buy/Sell Transportation Revenue

The Rangeland Pipeline system, which includes the Rangeland and MAPL pipelines, 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 RMC and RPC, RMC has contracted for the entire capacity of Rangeland pipeline. Customers who wish to transport product on Rangeland pipeline may either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) 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.

Substantially all of the pipelines that comprise the Rangeland Pipeline system are subject to the jurisdiction of the Alberta Energy Utilities Board (EUB). The Canadian portion of the segment of the Rangeland Pipeline system that connects to the Western Corridor system at the U.S.-Canadian border is subject to 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.

Gathering and Blending

We purchase, gather, blend and resell crude oil in our PMT operations. Our PMT gathering and blending system in California s San Joaquin Valley is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our West Coast pipeline transportation business. The gathering network effectively extends our pipeline network to capture additional supplies of crude oil for transportation on our trunk pipelines to Los Angeles.

The contribution of our PMT gathering and blending operations 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 and natural gasoline PMT buys for use in its blending operations and the price of the blended crude oil it sells. Costs and sales prices are impacted by crude oil prices generally, 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 a different price basis. Finally, it varies with the volumes gathered and blended. 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.

Our blending margins are a function of the cost of the heavy and light crude oils and natural gasoline that we buy and blend, relative to the price of the blended crude oil we sell. Blending margins have exceeded their historical averages in the first eight months of 2004. In September 2004, blending margins declined. Foreign imports of crude oil into the Los Angeles Basin were highly discounted relative to West Texas Intermediate (WTI) prices, which reduced demand for and prices of local California crude oil, including crude oil gathered and blended by us in the San Joaquin Valley. As the demand for and price of our blended crude oil has fallen, we have taken action to cancel certain purchase contracts beginning in the fourth quarter 2004, and to reduce the volume we gather, blend and sell. In addition, margins on one particular contract declined as the difference between purchases made on a WTI price basis and sales made on a West Coast price basis deviated from historical norms. This situation may continue in the fourth quarter of 2004, and perhaps through to this contract s maturity in the first quarter of 2005.

Acquisitions and New Projects

We intend to continue to pursue acquisitions and new projects for development of additional midstream assets, including pipeline, storage and terminal facilities that are accretive to our cash flow and complement our existing business. We expect to fund acquisitions and new projects with a combination of debt and additional Partnership units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

Operating Expenses

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to run the various pump stations along our pipelines. 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 release of oil to the extent not covered by insurance.

Employees

We do not have any employees, except in Canada. Our general partner, which provides employees to conduct our U.S. operations, and our Canadian subsidiaries collectively employ approximately 300 individuals who directly support our operations. Our general partner and our Canadian subsidiaries consider their employee relations to be good. None of these employees are subject to a collective bargaining agreement. 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

The cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries underlying operating results.

Critical Accounting Policies and Estimates

Our condensed 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 1 Summary of Significant Accounting Policies , to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2003) 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. Determining 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 utilize in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment.

We depreciate the components of our property and equipment 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. When necessary, the assets useful lives are revised and the impact on depreciation is treated 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 use outside environmental consultants to assist us in making these estimates. In addition, generally accepted accounting principles in the United States of America require us to establish liabilities for the costs of asset retirement obligations when the retirement date is determinable. We will record such liabilities only when such date is determinable.

From time to time, a shipper or group of shippers may initiate a regulatory proceeding or other action challenging the tariffs we charge or have charged. In such cases, we assess the proceeding on an ongoing basis as to its likely outcome and as to the dollar amounts involved 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 displacement oil, pipeline linefill and minimum tank volumes is carried in our accounts at the lower of cost and market value. This inventory is held for our long-term use and for the operation of our pipelines and storage facilities and as such is recorded in our property and equipment balance. We are exposed to the potential for a write-down to market value. A write-down will likely occur in future years as oil prices tend to be cyclical. However, such a write-down would be a non-cash expense but would not be realized, if at all, until we were to sell such inventory for a price less than our cost.

Results of Operations

Three Months Ended September 30, 2004 Compared to Three Months Ended September 30, 2003

Summary

	Three Months Ended September 30,			
	2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Net income	$ 9,890	$ 6,879	$ 3,011	44%
Net income per limited partner unit				
Basic and diluted	$ 0.33	$ 0.30	$ 0.03	10%

The results of the three months ended September 30, 2004 reflect three acquisitions: Pacific Terminals, which was acquired on July 31, 2003; the Rangeland Pipeline system, which was acquired on May 11, 2004; and the MAPL pipeline, which was acquired on June 30, 2004. Pacific Terminals experienced an increase in storage and distribution revenues due to increased storage capacity and higher utilization. The period also reflects the benefit of increased volumes and revenue on our Rocky Mountain pipelines. These increases were partially offset by lower margins in our West Coast gathering and blending operations. There were approximately 31% more weighted average limited partner units outstanding in the three months ended September 30, 2004 due to the sale of additional common units to partially fund the acquisitions of

the Pacific Terminals storage and distribution system, the Rangeland Pipeline system and the MAPL pipeline.

Segment Information

West Coast	Three Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Operating income	$ 11,355	$ 10,753	$ 602	6%
Operating data:				
Pipeline throughput (bpd)	139.7	146.4	(6.7)	-5%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system on July 31, 2003. This increase was partially offset by lower margins in the gathering and blending operations. Margins in the gathering and blending operations were adversely affected by competitive pricing pressures as a result of steeply discounted foreign crude entering the West Coast markets. In addition, a change in refined products specifications reduced demand for PMT s blended crude. Throughput during the third quarter of this year was reduced by

lower OCS volumes due to natural production declines and lower SJV light crude volumes due to natural field decline. Throughput was also reduced by higher light crude runs at Bakersfield area refineries which reduces the volumes available to move south to Los Angeles. The impact of lower volumes was offset by increased tariff rates and a more favorable tariff mix.

Rocky Mountains	Three Months Ended September 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating income	$ 7,533	$ 4,100	$ 3,433	84%
Operating data (bpd):				
Rangeland pipeline system				
Sundre North	21.8		n.a.	n.a.
Sundre South	46.8		n.a.	n.a.
Western Corridor system	23.1	17.7	5.4	31%
Salt Lake City Core system	75.2	68.3	6.9	10%
AREPI pipeline	47.4	47.8	(0.4)	-1%
Frontier pipeline	51.4	47.9	3.5	7%

Operating income increased due to higher volumes on the Western Corridor system, increased volumes on our systems that transport oil into the Salt Lake City area, and the benefit of a full quarter s operations of the Rangeland Pipeline system. The increase into Salt Lake City reflects increased demand and the benefit of the 9,000 bpd expansion that was completed in the second quarter of 2004.

Statement of Income Discussion and Analysis

Revenues

	Three Months Ended September 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline transportation revenue	$ 28,160	$ 25,501	$ 2,659	10%
Storage and distribution revenue	8,391	4,710	3,681	78%
Pipeline buy/sell transportation revenue	7,972		7,972	
Crude oil sales, net of purchases:				
Crude oil sales	106,760	102,740	4,020	4%
Crude oil purchases	(103,192)	(96,833)	6,359	7%
Crude oil sales, net of purchases	3,568	5,907	(2,339)	-40%
Net revenue before operating expenses	$ 48,091	$ 36,118	$ 11,973	33%

Pipeline transportation revenues were higher mainly due to higher volumes on the Western Corridor system and increased demand by Salt Lake City area refineries, as well as higher tariffs and a more favorable tariff mix in California.

Increased storage and distribution revenue reflects a full quarter of operations of the Pacific Terminals storage and distribution system, which was acquired on July 31, 2003.

Pipeline buy/sell transportation revenues of $8.0 million relate to a full quarter of operations of the Rangeland pipeline system, which was acquired on May 11, 2004.

The decrease in our West Coast gathering and blending unit s crude oil sales, net of purchases, for the three months ended September 30, 2004, was primarily the result of lower margins in our blending activities resulting from lower blending volumes due to a change in refined products specifications, as well as from competitive pricing pressures due to steeply discounted foreign crude entering the West Coast markets. We consider this gathering and blending activity to be complementary to our pipeline transportation operations.

Expenses

	Three Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Operating expenses	$ 22,589	$ 16,630	$ 5,959	36%
Transition costs	199		199	
General and administrative	3,762	3,305	457	14%
Depreciation and amortization	6,821	5,049	1,772	35%
	$ 33,371	$ 24,984	$ 8,387	34 %

The increase in operating expense was related primarily to the acquisition of the Rangeland pipeline system in May 2004 and the MAPL pipeline on June 30, 2004, as well as a full quarter of operations of the Pacific Terminals storage and distribution system that was acquired on July 31, 2003. We also experienced higher field operating and maintenance costs in the Rocky Mountains as a result of the timing of internal tank inspections, repairs resulting from internal line inspections and increased expenditures on flow improver this quarter to improve pipeline throughput capacity.

Transition costs were incurred for transition services provided by the sellers of the Rangeland and MAPL Pipeline systems, as well as for consulting and other out-of-pocket costs incurred in connection with the integration of these systems.

The increase in general and administrative expense was mainly attributable to personnel and administration costs associated with marketing, accounting and administrative support functions in our new regional Calgary office, following the acquisition of the Rangeland pipeline system in May 2004.

The increase in depreciation and amortization includes $1.8 million for depreciation on the Rangeland pipeline system.

Other Income and Expenses

	Three Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Share of net income of Frontier	$ 406	$ 414	$ (8)	-2%

Interest expense	$	5,234	$	4,782	$	452	9%
Income tax expense	$	221			$	221	

Our weighted average borrowings during the three months ended September 2004 were $335 million compared to $295 million in the corresponding period in 2003. The 2004 period average includes borrowings for our Canadian acquisition. The 2003 period average reflects the acquisition of Pacific Terminals on July 31, 2003. The effect of the increase in average borrowings was partly offset by a lower weighted average interest rate of 5.8% for the three months ended September 30, 2004 compared to a weighted average interest rate of 6.5% in 2003. The decrease in the average interest rate was due in part to renegotiation of interest rates in December 2003 under our credit facilities, and also to lower market interest rates.

The income tax expense for the period ended September 30, 2004 relates to the income of the Rangeland pipeline system acquired in May 2004. Our Canadian subsidiaries are taxable entities and the repatriation of funds into the U.S. is subject to Canadian withholding tax.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Summary

	Nine Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Net income	$ 27,095	$ 18,633	$ 8,462	45%
Net income per limited partner unit				
Basic	$ 0.95	$ 0.85	$ 0.10	12%
Diluted	$ 0.94	$ 0.84	$ 0.10	12%
Recurring net income(1)	$ 29,996	$ 18,633	$ 11,363	61%
Recurring net income per limited partner unit				
Basic	$ 1.05	$ 0.85	$ 0.20	24%
Diluted	$ 1.05	$ 0.84	$ 0.21	25%

(1) Recurring income excludes an expense of $2.9 million incurred in connection with the repayment of our term loan, including a $2.3 million non-cash write-off of deferred financing costs and a $0.6 million cash expense for related interest rate swap terminations.

Net income for the nine months ended September 30, 2004 includes the operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003 and the operations of Rangeland Pipeline system after acquiring these assets on May 11, 2004. Net income for the 2004 period also reflects a $2.9 million expense incurred in connection with the repayment of our term loan, which includes a $2.3 non-cash write-down of previously deferred financing costs and a $0.6 million charge to terminate interest rate swap agreements. These expenses are considered non-recurring. Accordingly, we exclude these amounts in reporting recurring net income.

The increase in recurring net income reflects the benefit of (i) the operation, since July 31, 2003, of Pacific Terminals storage and distribution system, (ii) higher volumes and revenue on the Rocky Mountain pipelines, and (iii) the operations of the Rangeland Pipeline system acquired in May 2004. These increases were partially offset by lower volumes and revenue from the West Coast pipelines and lower West Coast gathering and blending margins. There were approximately 30% more weighted average limited partner units outstanding in the nine months ended September 30, 2004 due to the sale of additional common units to partially fund the acquisitions of the Pacific Terminals storage and distribution system, the Rangeland Pipeline system and the MAPL pipeline.

Segment Information

Nine Months

West Coast	Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Operating income	$ 37,702	$ 30,773	$ 6,929	23%
Operating data:				
Pipeline throughput (bpd)	137.6	154.0	(16.4)	-11%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system. This increase was offset by a reduction in pipeline transportation revenue and lower margins in our gathering and blending operations. Average daily pipeline throughput decreased to 137,600 barrels per day for the nine months ended September 30, 2004, compared to 154,000 barrels per day for the corresponding period of the prior year. Throughput during the first nine months of this year was adversely affected by refinery maintenance activities. In addition, OCS volumes were lower due to natural field decline. A higher tariff beginning May 1, 2004 on Line 2000 partially offset the effects of lower volumes. The lower gathering and blending margins resulted from lower blending volumes due to a change in refined products specifications, which reduced demand for our blended crude oil, as well as competitive pricing pressures due to steeply discounted foreign crude oil entering the West Coast markets. We consider this gathering and blending activity to be complementary to our pipeline transportation operations.

Rocky Mountains	Nine Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Operating income	$ 16,890	$ 10,719	$ 6,171	58%
Operating data (bpd):				
Rangeland pipeline system				
Sundre North	21.6		n.a.	n.a.
Sundre South	47.6		n.a.	n.a.
Western Corridor system	19.7	16.2	3.5	22%
Salt Lake City Core system	70.3	65.9	4.4	7%
AREPI pipeline	45.8	41.6	4.2	10%
Frontier pipeline	48.5	41.5	7.0	17%

The increase in Rocky Mountains operating income was primarily due to increased demand by refineries in the Salt Lake City area this year, compared to 2003 when demand was lower due to refinery turnarounds. In addition, we acquired the Rangeland pipeline system on May 11, 2004.

Statement of Income Discussion and Analysis

Revenue

	Nine Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Pipeline transportation revenue	$ 79,879	$ 76,579	$ 3,300	4%
Storage and distribution revenue	27,773	4,710	23,063	490%
Pipeline buy/sell transportation revenue	11,662		11,662	
Crude oil sales, net of purchases:				
Crude oil sales	293,125	288,070	5,055	2%
Crude oil purchases	(278,689)	(271,554)	7,135	3%
Crude oil sales, net of purchases	14,436	16,516	(2,080)	-13%
Net revenue before operating expenses	$ 133,750	$ 97,805	$ 35,945	37%

Higher Rocky Mountain pipeline revenue due to increased demand by Salt Lake City area refineries was partially offset by lower West Coast pipeline revenue due to lower volumes as described above.

Higher storage and distribution revenue in 2004 reflects nine months of operations of the Pacific Terminals storage and distribution system that was acquired on July 31, 2003.

Pipeline buy/sell transportation revenue of $11.7 million relates to the operations of the Rangeland pipeline system, which was acquired on May 11, 2004.

The decrease in net crude oil sales for 2004 was primarily the result of lower West Coast blending volumes due to a change in refined products specifications, which reduced demand for our blended crude oil, as well as competitive pricing pressures due to steeply discounted foreign crude oil entering the West Coast markets. We consider this gathering and blending activity to be complementary to our pipeline transportation operations.

Expenses

	Nine Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Operating expenses	$ 62,189	$ 43,622	$ 18,567	43%
Transition costs	383	397	(14)	-4%
General and administrative	11,252	10,289	963	9%
Depreciation and amortization	17,776	13,435	4,341	32%
	$ 91,600	$ 67,743	$ 23,857	35 %

The increase in operating expense was related primarily to the acquisition of the Pacific Terminals storage and distribution assets on July 31, 2003 and the Rangeland pipeline system on May 11, 2004. We also experienced higher field operating and maintenance costs and higher power costs in the Rocky Mountains as a result of timing of internal line inspections, increased expenditure on flow improver and increased volumes and higher natural gas prices. This was offset by lower maintenance and power costs in the West Coast.

Transition costs in 2003 consisted of employee transition bonus payments related to our purchase of the Western Corridor and Salt Lake City Core systems in 2002. Transition costs in 2004 were incurred for transition services provided by the sellers of the Rangeland and MAPL pipeline systems, as well as for consulting and other out-of-pocket costs incurred in connection with the integration of these systems.

The increase in general and administrative expense was in part due to the acquisition of the Rangeland pipeline system in May 2004, increased personnel costs related to company growth and increased costs for regulatory compliance.

The increase in depreciation and amortization includes $1.9 million for depreciation on the Pacific Terminals storage and distribution system and $2.4 million for depreciation on the Rangeland pipeline system.

Other Income and Expenses

	Nine Months Ended September 30, 2004	2003	Change	Percent
	(In thousands)			
	(unaudited)			
Share of net income of Frontier	$ 1,190	$ 1,141	$ 49	4%
Interest expense	$ 13,743	$ 12,930	$ 813	6%
Write-off of deferred financing costs and interest rate swap termination expense	$ 2,901		$ 2,901	
Income tax expense	$ 207		$ 207	

Our increased share of Frontier net income was attributable to increased volumes on Frontier pipeline, offset by increased expenses for flow improver.

The increase in interest cost was due to borrowings incurred to partially fund the acquisition of Pacific Terminals storage and distribution system and the Rangeland Pipeline system. Our weighted average borrowings during the nine months ended September 30, 2004 were $304 million compared to $248 million in the corresponding period in 2003. The effect of this increase was partially offset by a decrease in interest expense associated with a renegotiation of interest rates in December 2003 under our credit facilities and lower market interest rates. The combination of lower renogiated interest rates and lower market rates led to a lower weighted average interest rate of 5.8% for the first nine months in 2004 compared to a weighted average interest rate of 7.0% in 2003.

Write-off of deferred financing costs and interest rate swap termination expense relate to deferred financing costs of $2.3 million incurred in connection with the repayment of our term loan and $0.6 million of expense incurred to terminate related interest rate swaps.

The income tax expense for the period ended September 30, 2004 relates to the income of the Rangeland pipeline system acquired in May 2004. Our Canadian subsidiaries are taxable entities and the repatriation of funds into the U.S. is subject to Canadian withholding tax.

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, anticipated sustaining capital expenditures and scheduled debt payments in the next three years.

The financing plan for the construction of our proposed Pier 400 Project is under development, but will likely include both proceeds from debt and the issuance of additional Partnership units. The final structure will depend on market conditions.

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG 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 determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The SEC declared the registration statement effective on August 8, 2003. During the nine months ended September 30, 2004, we issued 4.6 million Partnership units pursuant to the registration statement. At September 30, 2004, we have approximately $280 million of remaining availability under this registration statement.

We intend to draw down on this shelf registration statement and use proceeds from borrowings under our existing and planned revolving credit facilities to finance our future acquisitions and development projects, including the Pier 400 Project. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

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 transported through our pipelines and the capacity leased in our storage tanks as described in Overview above. Our operating performance is also affected by prevailing economic conditions in the crude oil industry and financial, business and other factors, some of which are beyond our control, which could significantly impact future results.

Operating, Investing and Financing Activities

	Nine Months Ended September 30, 2004 (In thousands) (unaudited)	2003	Change
Net cash provided by operating activities	$ 42,014	$ 33,401	$ 8,613

Net cash used in investing activities	(151,143)	(162,122)	(10,979)
Net cash provided by financing activities	113,958	122,234	(8,276)

Net cash provided by operating activities

The increase in the net cash from operating activities of $8,613 million, or 26%, was the result of higher operating income, partially offset by an increase in cash used for working capital.

Net cash used in investing activities

The amount in 2004 relates primarily to our acquisition and development activities. The 2004 period includes $139.0 million related to the acquisition of the Rangeland Pipeline and MAPL Pipeline systems. Capital expenditures were $11.5 million in 2004, of which $1.5 million related to sustaining capital projects, $1.2 million related to the primarily to the transition of the Pacific Terminals storage and distribution system and our Canadian assets, and $6.3 million related to expansion. Additionally, we continue to develop the Pier 400 Project, for which we capitalized $2.5 million for the nine months ended September 30, 2004.

In 2003, net cash used in investing activities includes $159.9 million paid to date for the acquisition of the Pacific Terminals storage and distribution system assets on July 31, 2003. Additionally, capital expenditures were $2.3 million, of which $1.3 million related to sustaining capital projects, $0.9 million related to expansion projects, and $0.1 million related to transition projects.

Net cash provided by financing activities

The amount in 2004 of $114.0 million includes net proceeds of $128.6 million from our equity offerings completed in March and April, 2004, which were used principally to partly fund our Rangeland Pipeline and MAPL Pipeline acquisitions, $241.1 million net proceeds from our 7.125% unsecured senior notes offering which were used, in part, to repay our $225 million term loan, net proceeds of $11.1 million under our revolving credit facilities, and $41.8 million in distributions to the limited and general partner interests.

Net cash provided by financing activities in 2003 includes proceeds of $149.0 million under the revolving credit facility which were used to fund, in part, the acquisition of the Pacific Terminals storage and distribution system. It also includes net proceeds and related contribution from our general partner of $133.7 million from our sale of additional common units, which were used to repay $90.0 million of debt under our revolving credit facility and to redeem 1.7 million outstanding common units totaling $40.8 million held by our general partner, which were cancelled after redemption. Distributions to our limited partners and our general partner were $29.7 million.

Capital Requirements

Generally, our crude oil transportation and storage 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, and adding new pump stations or pipeline connections to increase our transportation throughput and revenue.

We have forecasted total capital expenditures of $16 million in 2004, including $11 million for expansion projects, $3 million for transition capital projects and $2 million for sustaining capital projects.

Debt Obligations

At September 30, 2004, our debt obligations include: (i) $38.0 million on our U.S. revolving credit facility (ii) Cdn$65 million (U.S.$51.4 million) on our senior secured Canadian revolving credit facility, (iii) $248.7 million on our 7.125% senior unsecured notes, and (iv) Cdn$4.3 million (U.S.$3.4 million) payable to the seller of the MAPL assets. For further discussion of these debt obligations see Footnote 5 Long-term Debt to the financial statements.

Off-Balance Sheet Arrangements

The Partnership has no off-balance sheet arrangements.

Accounting Pronouncements

See discussion of newly issued accounting pronouncements in Note 1 Summary of Significant Accounting Policies in the accompanying condensed 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 interest rate risk, crude oil price risk and currency exchange rate risk. We utilize various derivative instruments to manage our exposure to our principal market risks. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter commodity positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks.

We have interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six 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 callable at the same dates and terms as our 7.125% Senior Notes. We elected to apply hedge accounting to account for the interest rate swaps. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of $80 million of the 7.125% Senior Notes are recorded into earnings each period. During the three months ended September 30, 2004, we recognized reductions in interest expense of $0.7 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. During the three months ended September 30, 2004, we measured the hedge effectiveness of these interest rate swaps and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of these interest rate swaps was a gain of approximately $2.9 million at September 30, 2004.

We are subject to risks resulting from interest rate fluctuations as the interest cost on $169.4 million of our outstanding debt is based on variable rates. If the LIBOR or Canadian Bankers Acceptance discount rates were to increase 1.0% for the remainder of 2004, our interest expense would increase approximately $0.4 million based on the outstanding debt at September 30, 2004.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our minimal exposure to market price volatility related to our inventory or future sales of crude oil. We do not enter into speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying condensed consolidated balance sheets. In our PMT operations we purchase crude oil for subsequent blending, transportation and resale primarily in the Los Angeles Basin. 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, 2004 and 2003, crude oil sales, net of purchases were net of $2.3 million and $0.3 million, respectively, reflecting changes in the fair value of PMT s derivative instruments for its marketing activities. In addition, 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, until the related revenue is reflected in the consolidated statements of income. As of September 30, 2004, $1.8 million relating to the changes in the fair value of derivative instruments was included in accumulated other comprehensive income.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the quarterly period ended September 30, 2004, Irvin Toole, Jr., Chief Executive Officer of our General Partner, and Gerald A. Tywoniuk, Chief Financial Officer of our General Partner, evaluated the effectiveness of our disclosure controls and procedures.

Based on this evaluation, they believe that:

our disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms; and

our disclosure controls and procedures were effective in ensuring that material information required to be disclosed by us in the report we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended September 30, 2004 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 8 Commitments and Contingencies in the accompanying condensed consolidated financial statements.

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 GP, Inc., 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 GP, Inc., 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 GP, Inc., 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 GP, Inc., 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.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Partnership 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, INC.**
its General Partner

By: /s/ IRVIN TOOLE, JR.
Irvin Toole, Jr.
President and Chief Executive Officer
(Principal Executive Officer)

November 2, 2004

By: /s/ GERALD A. TYWONIUK
Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

November 2, 2004

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