PACIFIC ENERGY PARTNERS LP
Form 10-Q
August 04, 2005

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2005

OR

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

5900 Cherry Avenue

Long Beach, CA 90805-4408

(Address of principal executive offices)

(562) 728-2800

(Registrant s telephone number, including area code)

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

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

There were 19,258,330 of the registrant s Common Units and 10,465,000 of the registrant s Subordinated Units outstanding at June 30, 2005.

PACIFIC ENERGY PARTNERS, L.P.

FORM 10-Q

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2005	December 31, 2004
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32,077	$ 23,383
Crude oil sales receivable	37,428	28,609
Transportation and storage accounts receivable	19,717	20,137
Canadian goods and services tax receivable	6,170	7,632
Insurance proceeds receivable (note 2)	6,705	
Due from related parties (note 3)	153	
Crude oil inventory	7,989	9,174
Prepaid expenses	3,180	4,159
Other	2,292	2,451
Total current assets	115,711	95,545
Property and equipment, net	713,070	718,624
Investment in Frontier	7,998	7,886
Other assets, net	47,516	47,850
	$ 884,295	$ 869,905
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 24,024	$ 14,872
Accrued crude oil purchases	38,362	27,231
Line 63 oil release reserve (note 2)	4,981	
Accrued interest	1,285	1,124
Due to related parties (note 3)		533
Derivatives liability current portion	1,078	400
Other	5,715	3,885
Total current liabilities	75,445	48,045
Senior notes and credit facilities, net (note 4)	359,209	357,163
Deferred income taxes	34,189	34,556
Environmental liabilities	6,980	7,269
Other liabilities	263	406
Total liabilities	476,086	447,439
Commitments and contingencies (notes 2 and 8)		
Partners capital:		
Common unitholders (19,258,330 and 19,158,747 units outstanding at June 30, 2005 and December 31, 2004, respectively)	354,598	361,427
Subordinated unitholders (10,465,000 units outstanding at June 30, 2005 and December 31, 2004)	36,949	41,521
General Partner interest	6,647	6,280
Undistributed employee long-term incentive compensation (note 5)		116
Accumulated other comprehensive income	10,015	13,122
Net partners capital	408,209	422,466
	$ 884,295	$ 869,905

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(in thousands, except per unit amounts)			
Pipeline transportation revenue	$ 27,747	$ 26,992	$ 55,784	$ 51,719
Storage and terminaling revenue	10,870	9,259	21,192	19,382
Pipeline buy/sell transportation revenue	8,116	3,690	17,222	3,690
Crude oil sales, net of purchases of $122,442 and $94,382 for the three months ended June 30, 2005 and 2004 and $236,833 and $175,497 for the six months ended June 30, 2005 and 2004	6,042	6,056	7,824	10,868
Net revenue	52,775	45,997	102,022	85,659
Expenses:				
Operating	25,292	20,867	47,046	39,784
Line 63 oil release costs (note 2)			2,000	
General and administrative	3,700	3,636	8,872	7,490
Accelerated long-term incentive plan compensation expense (note 5)			3,115	
Transaction costs (notes 3 and 6)			1,807	
Depreciation and amortization	6,606	5,713	13,135	10,955
	35,598	30,216	75,975	58,229
Share of net income of Frontier	490	391	847	784
Operating income	17,667	16,172	26,894	28,214
Interest expense	(5,844)	(4,383)	(11,442)	(8,509)
Write-off of deferred financing cost and interest rate swap termination expense		(2,901)		(2,901)
Other income	540	226	893	387
Income before income taxes	12,363	9,114	16,345	17,191
Income tax (expense) recovery:				
Current	245	(32)	(487)	(32)
Deferred	(388)	46	(217)	46
	(143)	14	(704)	14
Net income	$ 12,220	$ 9,128	$ 15,641	$ 17,205
Net income (loss) for the general partner interest (note 6)	$ 244	$ 183	$ (1,458)	$ 344
Net income for the limited partner interests	$ 11,976	$ 8,945	$ 17,099	$ 16,861
Basic and diluted net income per limited partner unit	$ 0.40	$ 0.30	$ 0.58	$ 0.62
Weighted average limited partner units outstanding:				
Basic	29,723	29,479	29,689	27,239
Diluted	29,742	29,632	29,708	27,402

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(Unaudited)

	Limited Partner Units		Limited Partner Amounts		General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income	Total
	Common (in thousands)	Subordinated	Common	Subordinated				
Balance, December 31, 2004	19,159	10,465	$ 361,427	$ 41,521	$ 6,280	$ 116	$ 13,122	$ 422,466
Net income (note 6)			11,075	6,024	(1,458)			15,641
Distribution to partners			(19,449)	(10,596)	(613)			(30,658)
General partner contribution (note 6)					2,407			2,407
Employee compensation under long-term incentive plan						2,886		2,886
Issuance of common units pursuant to long-term incentive plan (note 5)	99		1,545		31	(3,002)		(1,426)
Foreign currency translation adjustment							(2,301)	(2,301)
Change in fair value of hedging derivatives							(806)	(806)
Balance, June 30, 2005	19,258	10,465	$ 354,598	$ 36,949	$ 6,647	$	$ 10,015	$ 408,209

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands)			
Net income	$ 12,220	$ 9,128	$ 15,641	$ 17,205
Change in fair value of hedging derivatives	327	9,140	(806)	4,904
Change in foreign currency translation adjustment	(1,765)	2,429	(2,301)	2,429
Comprehensive income	$ 10,782	$ 20,697	$ 12,534	$ 24,538

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 15,641	$ 17,205
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	13,135	10,955
Amortization of debt issue costs and debt discount accretion	937	670
Write-off of deferred financing costs		2,321
Non-cash portion of employee compensation under long-term incentive plan	1,429	1,351
Deferred tax expense (benefit)	217	(46)
Share of net income of Frontier	(847)	(784)
Other non-cash adjustments	98	
Distributions from Frontier, net	650	668
	31,260	32,340
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(8,819)	4,270
Transportation and storage accounts receivable	1,699	(8,757)
Insurance proceeds receivable	(6,705)	
Other current assets and liabilities	2,116	267
Accounts payable and other accrued liabilities	11,095	3,677
Accrued crude oil purchases	11,113	(2,271)
Line 63 oil release reserve	4,981	
Other non-current assets and liabilities	(522)	(261)
	14,958	(3,075)
NET CASH PROVIDED BY OPERATING ACTIVITIES	46,218	29,265
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions		(139,050)
Additions to property and equipment	(9,877)	(7,896)
Other	(98)	
NET CASH USED IN INVESTING ACTIVITIES	(9,975)	(146,946)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses		125,881
Capital contributions from the general partner	2,438	2,690
Net proceeds from senior notes offering		241,086
Repayment of term loan		(225,000)
Proceeds from credit facilities	66,283	154,168
Repayment of credit facilities	(64,326)	(141,500)
Deferred financing costs	(600)	(1,008)
Distributions to partners	(30,658)	(27,081)
Related parties	(686)	607
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(27,549)	129,843
NET INCREASE IN CASH AND CASH EQUIVALENTS	8,694	12,162
CASH AND CASH EQUIVALENTS, beginning of reporting period	23,383	9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 32,077	$ 21,861

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2005

(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 business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. See also Note 9 Subsequent Events .

The Partnership is managed by its general partner, Pacific Energy GP, LP, a Delaware limited partnership, which, prior to its conversion to a limited partnership on March 3, 2005, was Pacific Energy GP, Inc., a corporation owned 100% by a subsidiary of The Anschutz Corporation (TAC). On March 3, 2005, TAC sold all of its interest in Pacific Energy GP, Inc. to LB Pacific, LP (LBP), which was formed by the Lehman Brothers Merchant Banking Group (LBMB) in connection with the purchase (see Note 3 Related Party Transactions). Pacific Energy GP, LP is managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company.

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 six months ended June 30, 2005 are not necessarily indicative of the results of operations for the full year. All significant intercompany balances and transactions have been eliminated during the consolidation process.

The condensed consolidated financial statements include the ownership and results of operations of the Rangeland system, including the Mid-Alberta Pipeline (MAPL), since the acquisition of those assets on May 11, 2004 and June 30, 2004, respectively.

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, 2004. Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to the current year presentation.

Income Taxes

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

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

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 above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options and restricted units by application of the treasury stock method. There were no outstanding restricted units as of June 30, 2005 because of the accelerated vesting of units (see Note 5 Vesting of Unit Grants Under Long-Term Incentive Plan). Following is a reconciliation of the basic weighted average outstanding limited partner units to diluted weighted average limited partner units.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(in thousands)			
Basic weighted average limited partner units	29,723	29,479	29,689	27,239
Effect of restricted units		140		148
Effect of options	19	13	19	15
Diluted weighted average limited partner units	29,742	29,632	29,708	27,402

Allocation of Net Income

Net income is allocated to the Partnership s general partner and limited partners based on their respective interest in the Partnership. The Partnership s general partner is also directly charged with specific costs that it assumed in connection with its acquisition by LBP and for which the limited partners are not responsible (see Note 6 Allocation of Net Income).

New Accounting Pronouncements

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

On March 30, 2005 the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), to clarify the term *conditional asset retirement obligation* as that term is used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. The Interpretation also clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for the Partnership no later than the end of fiscal years ending after December 15, 2005. The Partnership is in the process of determining the impact of FIN 47 on its financial statements.

2. LINE 63 OIL RELEASE RESERVE

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide induced by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through March 2006, the Partnership expects to incur an estimated total of $15.0 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of June 30, 2005, the Partnership had incurred approximately $11.5 million of the total expected costs related to the oil release for work performed through that date. Additionally, the Partnership expensed $0.6 million, all in the second quarter, for the repair of Line 63 and expects to incur $1.2 million of Line 63 capital improvements in future periods.

The Partnership has a pollution liability insurance policy with a $2.0 million deductible that covers containment and clean-up costs, third-party claims and penalties. The insurance carrier has acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. The Partnership believes that, subject to the $2.0 million deductible, it will be entitled to recover substantially all of its clean-up costs and any third-party claims associated with the release. The Partnership s insurance coverage will not cover the cost to repair the pipeline. As of June 30, 2005, the Partnership has recovered $6.3 million from insurance and recorded a receivable of $6.7 million for insurance recoveries it deems probable.

The Partnership recorded $2.0 million in net costs in Line 63 oil release costs in the accompanying condensed consolidated financial statements for the six months ended June 30, 2005. The $2.0 million net oil release costs consist of the $15.0 million of accrued costs relating to the release, net of insurance recovery of $6.3 million and accrued insurance receipts of $6.7 million.

The foregoing estimates are based on facts known at the time of estimation and the Partnership s assessment of the ultimate outcome. Among the many uncertainties that impact the estimates are the necessary regulatory approvals for, and potential modification of, remediation and repair plans, the ongoing assessment of the impact of soil and water contamination, the uncertainty of the geological conditions that will be encountered during the permanent repairs of the pipeline, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that costs incurred in excess of this provision, if any, would not have a material adverse effect on the Partnership s financial condition, results of operations, or cash flows, though the Partnership believes that most, if not all, of any such excess cost, to the extent attributable to clean-up and third-party claims, would be recoverable through insurance. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

3. RELATED PARTY TRANSACTIONS

Sale of The Anschutz Corporation s Interest in the Partnership

On March 3, 2005, TAC sold all of its interest in Pacific Energy GP, Inc. to LBP, which was formed by LBMB in connection with the purchase. The acquisition by LBP (the LB Acquisition) included the 100% ownership interest in Pacific Energy GP, Inc., which owned (i) 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 34.6% limited partner interest in the Partnership. Immediately prior to the closing of the

LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP (the General Partner). Immediately following the consummation of the LB Acquisition, the General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of the Partnership s General Partner to a limited partnership, the General Partner ceased to have a board of directors, and is now managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company (PEM or the Managing General Partner), which is 100% owned by LBP. PEM has a board of directors (the Board of Directors or Board) that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of the General Partner and the Partnership. All of the officers and employees of Pacific Energy GP, Inc. were transferred to fill the same positions with PEM, and the PEM Board established the same committees as had been maintained by Pacific Energy GP, Inc. prior to the LB Acquisition. PEM also adopted Pacific Energy GP, Inc. s governance guidelines and its compensation structure and employee benefits plans and policies.

Additionally, on March 21, 2005, an affiliate of First Reserve Corporation (First Reserve) acquired from LBMB a 30% partnership interest in LBP. LBMB and its affiliates continue to own a 70% partnership interest in LBP.

Cost Reimbursements

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

Special Agreement: On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors of Pacific Energy GP, Inc., entered into a Special Agreement and a Consulting Agreement with PEM. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors of Pacific Energy GP, Inc. effective March 3, 2005. Mr. Polson was paid approximately $0.9 million, representing accrued but unused vacation, accrued salary through March 3, 2005 and payment in satisfaction of other obligations under his employment agreement. The severance portion of this payment of approximately $0.9 million was recorded as an expense in Transaction costs in the accompanying condensed consolidated income statements (see Note 6 Allocation of Net Income). LBP reimbursed this amount, which was recorded as a partner s capital contribution. Pursuant to the Consulting Agreement, Mr. Polson has agreed to perform advisory services to PEM from time to time as shall be mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson s services under the Consulting Agreement, which has a one-year term, Mr. Polson will receive a monthly consulting fee of $12,500 and reimbursement of all reasonable business expenses incurred or paid by Mr. Polson in the course of performing his duties thereunder.

LBP and TAC: LBP and TAC reimbursed the Partnership for certain other costs relating to the LB Acquisition. These included $1.2 million for the Consent Solicitation (as defined and further described in Note 4 Long-Term Debt , below) and $0.3 million for legal and other expenses (also see Note 6 Allocation of Net Income).

Other Related Party Transactions

Lehman Brothers, Inc.: Lehman Brothers, Inc., an affiliate of LBP, is acting as the exclusive financial advisor in the pending acquisition of certain assets from Valero L.P. Additionally, Lehman Brothers has committed to provide the Partnership with 50% of the $700 million financing commitment and will act as a lead underwriter in any debt or equity offering (see Note 9 Subsequent Events). These agreements with Lehman Brothers, Inc. were reviewed and approved by the Conflicts Committee of the Board of Directors.

Revenue from Related Parties: Rocky Mountain Pipeline System LLC (RMPS), a subsidiary of the Partnership, receives an operating fee and 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 $0.2 million and $0.1 million for each of the three months ended June 30, 2005 and 2004 and $0.4 million and $0.3 million for each of the six months ended June 30, 2005 and 2004, respectively.

Due from (to) Related Parties: Due from related parties, which includes payroll related items, consists of $0.2 million due from PEM and $0.5 million due to Pacific Energy GP, Inc. at June 30, 2005 and December 31, 2004, respectively.

4. LONG-TERM DEBT

The Partnership s long-term debt obligations are shown below:

	June 30, 2005		December 31, 2004	
	(in thousands)			
Senior secured U.S. revolving credit facility, bearing interest at 4.6% on June 30, 2005, due July 2007	$	53,000	$	51,000
Senior secured Canadian revolving credit facility, bearing interest at 4.9% on June 30, 2005, due May 2007		53,035		54,005
Senior Notes, net of unamortized discount of $4,046 and $4,202 and including fair value increases of $3,528 and $2,693, respectively, with a coupon of 7 1⁄8%, due June 2014		249,482		248,491
Future payment for MAPL assets, net of unamortized discount of $387 and $480, respectively, due June 2007		3,692		3,667
Long-term debt	$	359,209	$	357,163

Under the Indenture governing the Partnership s 7 1⁄8% Senior Notes due 2014 (the Senior Notes), the Partnership would have been required to make a Change of Control Offer to the holders of its Senior Notes if the LB Acquisition caused a rating decline by a credit rating agency. In order to avoid triggering the Change of Control Offer provision, the Partnership solicited the consent (the Consent Solicitation) of the holders of its Senior Notes to amend certain provisions of the Indenture, including an amendment to the definition of Change of Control. The Consent Solicitation was completed on February 10, 2005 with a majority of the holders of the Senior Notes consenting to the adoption of the proposed amendments, and as such, the proposed amendments were approved. Thereafter, a supplemental indenture that incorporated the proposed amendments was executed by the parties to the Indenture. Fees of $0.6 million paid to holders of the Senior Notes were capitalized and included in Other assets in the accompanying condensed consolidated balance sheet at June 30, 2005 and will be amortized over the remaining life of the Senior Notes. Other solicitation related fees and expenses of approximately $0.6 million are included in Transaction costs in the accompanying condensed consolidated statements of income. LBP and TAC reimbursed the Partnership for the costs of the Consent Solicitation, which are recorded as a partner s capital contribution (see Note 3 Related Party Transactions).

Additionally, the U.S. and Canadian revolving credit facilities also contained change of control provisions. The Partnership amended the U.S. and Canadian revolving credit facilities to account for the change in control of its General Partner.

5. VESTING OF UNIT GRANTS UNDER LONG-TERM INCENTIVE PLAN

On March 3, 2005, in connection with the LB Acquisition and with the change in control of the Partnership s General Partner, all restricted units outstanding under the Partnership s Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. The Partnership issued 99,583 common units and recognized a compensation expense of $3.1 million, which is included in Accelerated long-term incentive plan compensation expense in the accompanying condensed consolidated statements of income.

6. ALLOCATION OF NET INCOME

The allocation of net income between the Partnership s General Partner and limited partners is as follows.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(in thousands)			
Net income	$ 12,220	$ 9,128	$ 15,641	$ 17,205
Transaction costs reimbursed by general partner:				
Senior Notes consent solicitation and other costs			893	
Severance and other costs			914	
Total transaction costs reimbursed by general partner			1,807	
Income before transaction costs reimbursed by general partner	12,220	9,128	17,448	17,205
General partner s share of income	2 %	2 %	2 %	2 %
General partner allocated share of net income before transaction costs	244	183	349	344
Transaction costs reimbursed by general partner			(1,807)	
Net income (loss) allocated to general partner	$ 244	$ 183	$ (1,458)	$ 344
Income before transaction costs reimbursed by general partner	$ 12,220	$ 9,128	$ 17,448	$ 17,205
Limited partners share of income	98 %	98 %	98 %	98 %
Limited partners share of net income	$ 11,976	$ 8,945	$ 17,099	$ 16,861
Net income (loss) allocated to general partner	$ 244	$ 183	$ (1,458)	$ 344
Net income allocated to limited partners	11,976	8,945	17,099	16,861
Net income	$ 12,220	$ 9,128	$ 15,641	$ 17,205

LBP and TAC reimbursed the Partnership for certain costs incurred in connection with the LB Acquisition. The Partnership was reimbursed $1.2 million for costs incurred in connection with the Consent Solicitation, $0.3 million of legal and other costs and $0.9 million relating to severance costs (see Note 3 Related Party Transactions), for a total of $2.4 million. Of the $1.2 million incurred for the consent solicitation, $0.6 million was capitalized as deferred financing costs and $0.6 million was expensed in the six months ended June 30, 2005.

7. SEGMENT INFORMATION

The Partnership s business and operations are organized into two regional business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. The West Coast Business Unit includes: (i) Pacific Pipeline System LLC, owner of Line 2000 and Line 63, (ii) Pacific Marketing and Transportation LLC, owner of the PMT gathering and blending system, and (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system. The Rocky Mountain Business Unit includes: (i) Rocky Mountain Pipeline System LLC, owner of the Partnership s interest in various pipelines that make up the Western Corridor and Salt Lake City Core systems, (ii) Ranch Pipeline LLC, the owner of a 22.22% partnership interest in Frontier Pipeline Company, and (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate the Rangeland system (for the period since May 11, 2004). General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and business development, are not allocated to the individual business units. Information regarding these two business units is summarized below:

	West Coast Business Unit	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
	(in thousands)			
Three months ended June 30, 2005				
Business unit revenue:				
Pipeline transportation revenue	$ 15,194	$ 14,006	$ (1,453)	$ 27,747
Storage and distribution revenue	10,870			10,870
Pipeline buy/sell transportation revenue(1)		8,116		8,116
Crude oil sales, net of purchases(2)	5,866	206	(30)	6,042
Net revenue	31,930	22,328		52,775
Expenses:				
Operating	15,996	10,779	(1,483)	25,292
Depreciation and amortization	3,529	3,077		6,606
Total expenses	19,525	13,856		31,898
Share of net income of Frontier		490		490
Operating income from segments(4)	$ 12,405	$ 8,962		$ 21,367
Business unit assets(5)	$ 501,990	$ 342,420		$ 844,410
Capital expenditures(6)	$ 934	$ 2,535		$ 3,469
Three months ended June 30, 2004				
Business unit revenue:				
Pipeline transportation revenue	$ 16,494	$ 11,804	$ (1,306)	$ 26,992
Storage and distribution revenue	9,359		(100)	9,259
Pipeline buy/sell transportation revenue(1)		3,690		3,690
Crude oil sales, net of purchases(2)	6,056			6,056
Net revenue	31,909	15,494		45,997
Expenses:				
Operating	14,182	8,091	(1,406)	20,867
Depreciation and amortization	3,635	2,078		5,713
Total expenses	17,817	10,169		26,580
Share of net income of Frontier		391		391
Operating income from segments(4)	$ 14,092	$ 5,716		$ 19,808
Business unit assets(5)	$ 501,424	$ 317,209		$ 818,633
Capital expenditures(6)	$ 742	$ 3,185		$ 3,927

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	West Coast Business Unit	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
	(in thousands)			
Six months ended June 30, 2005				
Business unit revenue:				
Pipeline transportation revenue	$ 32,638	$ 26,461	$ (3,315)	$ 55,784
Storage and distribution revenue	21,342		(150)	21,192
Pipeline buy/sell transportation revenue(1)		17,222		17,222
Crude oil sales, net of purchases(2)	7,678	206	(60)	7,824
Net revenue	61,658	43,889		102,022
Expenses:				
Operating	30,503	20,068	(3,525)	47,046
Line 63 oil release costs(3)	2,000			2,000
Depreciation and amortization	7,006	6,129		13,135
Total expenses	39,509	26,197		62,181
Share of net income of Frontier		847		847
Operating income from segments(4)	$ 22,149	$ 18,539		$ 40,688
Business unit assets(5)	$ 501,990	$ 342,420		$ 844,410
Capital expenditures(6)	$ 1,684	$ 5,467		$ 7,151
Six months ended June 30, 2004				
Business unit revenue:				
Pipeline transportation revenue	$ 32,185	$ 22,347	$ (2,813)	$ 51,719
Storage and distribution revenue	19,582		(200)	19,382
Pipeline buy/sell transportation revenue(1)		3,690		3,690
Crude oil sales, net of purchases(2)	10,868			10,868
Net revenue	62,635	26,037		85,659
Expenses:				
Operating	28,888	13,909	(3,013)	39,784
Depreciation and amortization	7,400	3,555		10,955
Total expenses	36,288	17,464		50,739
Share of net income of Frontier		784		784
Operating income from segments(4)	$ 26,347	$ 9,357		$ 35,704
Business unit assets(5)	$ 501,424	$ 317,209		$ 818,633
Capital expenditures(6)	$ 1,539	$ 4,476		$ 6,015

(1) Includes the revenue of the Rangeland system, which was acquired on May 11, 2004 and June 30, 2004. Pipeline buy/sell transportation revenue reflects net revenues of approximately $0.7 million on gross revenues for buy/sell transactions of $28.0 million with different parties for the three months ended June 30, 2005 and net revenues of approximately $2.1 million on gross revenues for buy/sell transactions of $48.5 million with different parties for the six months ended June 30, 2005. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of $–––122,442 and $94,382 for the three months ended June 30, 2005 and 2004 and $236,833 and $175,497 for the six months ended June 30, 2005 and 2004, respectively.

(3) See Note 2 Line 63 Oil Release Reserve for further information.

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

	Three Months Ended June 30, 2005 (in thousands)	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Income Statement Reconciliation				
Operating income from above:				
West Coast Business Unit	$ 12,405	$ 14,092	$ 22,149	$ 26,347
Rocky Mountain Business Unit	8,962	5,716	18,539	9,357
Operating income from segments	21,367	19,808	40,688	35,704
Less: General and administrative expense	(3,700)	(3,636)	(8,872)	(7,490)
Less: Accelerated long-term incentive plan compensation expense			(3,115)	
Less: Transaction costs			(1,807)	
Operating income	17,667	16,172	26,894	28,214
Interest expense	(5,844)	(4,383)	(11,442)	(8,509)
Write-off of deferred financing cost and interest rate swap termination expense		(2,901)		(2,901)
Other income	540	226	893	387
Income tax benefit (expense)	(143)	14	(704)	14
Net income	$ 12,220	$ 9,128	$ 15,641	$ 17,205

(5) Business unit assets do not include assets related to the Partnership s parent level activities. As of June 30, 2005 and 2004, parent level related assets were $39,885 and $32,879 respectively.

(6) Capital expenditures do not include the Pier 400 project and other parent-level related capital expenditures. Pier 400 project and other parent-level related capital expenditures were $2.0 million and $1.6 million for the three months ended June 30, 2005 and 2004 and $2.7 million and $1.9 million for the six months ended June 30, 2005 and 2004, respectively.

8. CONTINGENCIES

The Partnership is involved in various regulatory disputes, litigation and claims arising out of its operations in the normal course of business (see also Note 2 Line 63 Oil Release Reserve). The Partnership is not currently a party to any legal or regulatory proceedings the resolution of which could be expected to have a material adverse effect on its business, financial condition, liquidity or results of operations.

9. SUBSEQUENT EVENTS

Valero Acquisition

On July 1, 2005, Pacific Energy Group LLC (PEG), a wholly owned subsidiary of the Partnership, entered into a Sale and Purchase Agreement (the Purchase Agreement), with Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P. and Shore Terminals LLC (the Sellers), pursuant to which PEG agreed to acquire certain terminal and pipeline assets from the Sellers for an aggregate purchase price of $455.0 million. The assets being purchased consist of (i) the Martinez Terminal and Richmond Terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia Terminals and the Paulsboro, New Jersey Terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four truck terminals and storage in the U.S. Rocky Mountains.

The Martinez and Richmond Terminals have 4.1 million barrels of combined storage capacity and handle refined products, blend stocks and crude oil. The terminals are connected to pipelines and to area refineries by pipelines and can also receive and deliver products by marine vessel or barge. The terminals also have truck racks for products delivery and receipt. The Richmond terminal has a rail spur for delivery and receipt of products.

The North Philadelphia Terminal, the South Philadelphia Terminal and the Paulsboro, New Jersey Terminal handle refined products and have a combined storage capacity of 3.2 million barrels. The terminals are connected to pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The 550-mile pipeline system, known as the West Pipeline System, consists of 550 miles of refined products pipeline extending from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. In addition, there are four products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels.

The Partnership expects to fund the acquisition on a permanent basis by issuing common units for approximately 60-65% of the purchase price and debt securities for approximately 35-40% of the acquisition price. The purchase is subject to the receipt of regulatory approvals and is expected to close by October 1, 2005.

Also, in connection with the purchase, the Partnership has received $700 million in financing commitments from Bank of America, N.A. and Lehman Brothers, Inc. These commitments include a new five-year $400 million secured revolving credit facility, which would partly fund the acquisition as well as repay and replace the Partnership s existing U.S. and Canadian revolving credit facilities. These commitments also include a $300 million, 364-day secured term credit facility, which would only be used to fund the acquisition if permanent financing is not obtained by the acquisition closing date.

Purchase Of Crude Oil and Contracts

On July 1, 2005, Pacific Marketing and Transportation LLC, a wholly owned subsidiary of the Partnership purchased certain crude oil contracts and crude oil inventories for approximately $2.2 million plus contingent payments over the next three and one half years based on specified performance criteria.

Distribution

On July 21, 2005, the Partnership declared a cash distribution of $0.5125 per limited partner unit, payable on August 12, 2005, to unitholders of record as of August 1, 2005.

10. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Given that certain, but not all subsidiaries of the Partnership are guarantors of its Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, the Partnership 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, the guarantors of the Senior Notes, are collectively referred to as the Guarantor Subsidiaries, and Pacific Pipeline System LLC, Pacific Terminals LLC, Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership and Aurora Pipeline Company, Ltd. 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 June 30, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Assets:					
Current assets	$ 11,264	$ 86,044	$ 58,494	$ (40,091)	$ 115,711
Property and equipment		129,989	583,081		713,070
Equity investments	388,766	194,123		(574,891)	7,998
Intercompany notes receivable	249,935	337,763		(587,698)	
Other assets	8,481	1,733	37,302		47,516
Total assets	$ 658,446	$ 749,652	$ 678,877	$ (1,202,680)	$ 884,295
Liabilities and partners capital:					
Current liabilities	$ 755	$ 57,199	$ 57,582	$ (40,091)	$ 75,445
Long-term debt	249,482	53,000	56,727		359,209
Deferred income taxes		617	33,572		34,189
Intercompany notes payable		249,935	337,763	(587,698)	
Other liabilities		135	7,108		7,243
Total partners capital	408,209	388,766	186,125	(574,891)	408,209
Total liabilities and partners capital	$ 658,446	$ 749,652	$ 678,877	$ (1,202,680)	$ 884,295

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	Balance Sheet December 31, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Assets:					
Current assets	$ 14,869	$ 80,320	$ 41,948	$ (41,592)	$ 95,545
Property and equipment		129,496	589,128		718,624
Equity investments	366,148	194,787		(553,049)	7,886
Intercompany notes receivable	283,550	338,884		(622,434)	
Other assets	7,223	1,993	38,634		47,850
Total assets	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905
Liabilities and partners capital:					
Current liabilities	$ 833	$ 44,177	$ 44,627	$ (41,592)	$ 48,045
Long-term debt	248,491	51,000	57,672		357,163
Deferred income taxes		470	34,086		34,556
Intercompany notes payable		283,550	338,884	(622,434)	
Other liabilities		135	7,540		7,675
Total partners capital	422,466	366,148	186,901	(553,049)	422,466
Total liabilities and partners capital	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905

	Statement of Income Three Months Ended June 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 20,077	$ 34,181	$ (1,483)	$ 52,775
Operating expenses		(10,322)	(16,453)	1,483	(25,292)
General and administrative expense(1)		(3,208)	(492)		(3,700)
Depreciation and amortization expense		(1,636)	(4,970)		(6,606)
Share of net income of Frontier		490			490
Operating income		5,401	12,266		17,667
Interest expense	(4,217)	(825)	(802)		(5,844)
Intercompany interest income (expense)		6,141	(6,141)		
Equity earnings	16,428	5,586		(22,014)	
Other income	9	434	97		540
Income tax (expense) benefit		(309)	166		(143)
Net income	$ 12,220	$ 16,428	$ 5,586	$ (22,014)	$ 12,220

(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 June 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 17,859	$ 29,544	$ (1,406)	$ 45,997
Operating expenses		(10,038)	(12,235)	1,406	(20,867)
General and administrative expense(1)		(3,390)	(246)		(3,636)
Depreciation and amortization expense		(1,648)	(4,065)		(5,713)
Share of net income of Frontier		391			391
Operating income		3,174	12,998		16,172
Interest expense	(754)	(3,294)	(335)		(4,383)
Intercompany interest income (expense)		4,871	(4,871)		
Equity earnings	9,878	7,864		(17,742)	
Other income (expense)	4	(2,737)	58		(2,675)
Income tax benefit			14		14
Net income	$ 9,128	$ 9,878	$ 7,864	$ (17,742)	$ 9,128

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

	Statement of Income Six Months Ended June 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 34,345	$ 71,202	$ (3,525)	$ 102,022
Operating expenses		(20,290)	(30,281)	3,525	(47,046)
Line 63 oil release costs			(2,000)		(2,000)
General and administrative expense(1)		(7,835)	(1,037)		(8,872)
Accelerated long-term incentive plan compensation expense		(2,675)	(440)		(3,115)
Transaction costs	(893)	(914)			(1,807)
Depreciation and amortization expense		(3,260)	(9,875)		(13,135)
Share of net income of Frontier		847			847
Operating income	(893)	218	27,569		26,894
Interest expense	(8,295)	(1,504)	(1,643)		(11,442)
Intercompany interest income (expense)		12,412	(12,412)		
Equity earnings	24,812	13,576		(38,388)	
Other income	17	600	276		893
Income tax expense		(490)	(214)		(704)
Net income	$ 15,641	$ 24,812	$ 13,576	$ (38,388)	$ 15,641

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

	Statement of Income Six Months Ended June 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 33,215	$ 55,457	$ (3,013)	$ 85,659
Operating expenses		(19,738)	(23,059)	3,013	(39,784)
General and administrative expense(1)		(7,218)	(272)		(7,490)
Depreciation and amortization expense		(3,243)	(7,712)		(10,955)
Share of net income of Frontier		784			784
Operating income		3,800	24,414		28,214
Interest expense	(754)	(7,420)	(335)		(8,509)
Intercompany interest income (expense)		8,618	(8,618)		
Equity earnings	17,954	15,574		(33,528)	
Other income (expense)	5	(2,618)	99		(2,514)
Income tax benefit			14		14
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205

(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 June 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net income	$ 12,220	$ 16,428	$ 5,586	$ (22,014)	$ 12,220
Change in fair value of hedging derivatives	327	327		(327)	327
Foreign currency translation adjustment	(1,765)	(1,765)	(1,765)	3,530	(1,765)
Comprehensive income	$ 10,782	$ 14,990	$ 3,821	$ (18,811)	$ 10,782

	Statement of Comprehensive Income Three Months Ended June 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net income	$ 9,128	$ 9,878	$ 7,864	$ (17,742)	$ 9,128
Change in fair value of hedging derivatives	9,140	9,140		(9,140)	9,140
Foreign currency translation adjustment	2,429	2,423	6	(2,429)	2,429
Comprehensive income	$ 20,697	$ 21,441	$ 7,870	$ (29,311)	$ 20,697

	Statement of Comprehensive Income Six Months Ended June 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net income	$ 15,641	$ 24,812	$ 13,576	$ (38,388)	$ 15,641

Change in fair value of hedging derivatives	(806)	(806)		806	(806)
Foreign currency translation adjustment	(2,301)	(2,301)	(2,301)	4,602	(2,301)
Comprehensive income	$ 12,534	$ 21,705	$ 11,275	$ (32,980)	$ 12,534

	Statement of Comprehensive Income Six Months Ended June 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205
Change in fair value of hedging derivatives	4,904	4,904		(4,904)	4,904
Foreign currency translation adjustment	2,429	2,423	6	(2,429)	2,429
Comprehensive income	$ 24,538	$ 25,281	$ 15,580	$ (40,861)	$ 24,538

	Statement of Cash Flows Six Months Ended June 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 15,641	$ 24,812	$ 13,576	$ (38,388)	$ 15,641
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(24,812)	(13,576)		38,388	
Distributions from subsidiaries	30,658	22,784		(53,442)	
Depreciation, amortization and other	333	5,062	10,224		15,619
Net changes in operating assets and liabilities	(49)	6,616	10,047	(1,656)	14,958
NET CASH PROVIDED BY OPERATING ACTIVITIES	21,771	45,698	33,847	(55,098)	46,218
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property, equipment and other		(3,752)	(6,223)		(9,975)
Intercompany	(914)			914	
NET CASH USED IN INVESTING ACTIVITIES	(914)	(3,752)	(6,223)	914	(9,975)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(23,067)	(38,652)	(20,014)	54,184	(27,549)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,210)	3,294	7,610		8,694
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713	17,523	3,147		23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 503	$ 20,817	$ 10,757	$	$ 32,077

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	Statement of Cash Flows Six Months Ended June 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(17,954)	(15,574)		33,528	
Distributions from subsidiaries	27,081	22,927		(50,008)	
Depreciation, amortization and other	22	7,401	7,712		15,135
Net changes in operating assets and liabilities	1,414	(8,619)	(8,193)	12,323	(3,075)
NET CASH PROVIDED BY OPERATING ACTIVITIES	27,768	24,089	15,093	(37,685)	29,265
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(139,050)		(139,050)
Additions to property, equipment and other		(5,751)	(2,145)		(7,896)
Intercompany	(369,657)	(91,155)		460,812	
NET CASH USED IN INVESTING ACTIVITIES	(369,657)	(96,906)	(141,195)	460,812	(146,946)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	343,915	81,184	127,871	(423,127)	129,843
NET DECREASE IN CASH AND CASH EQUIVALENTS	2,026	8,367	1,769		12,162
CASH AND CASH EQUIVALENTS, beginning of reporting period	746	8,603	350		9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 2,772	$ 16,970	$ 2,119	$	$ 21,861

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

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

Forward-Looking Statements

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

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil and other related products and buying, gathering, blending and selling crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read Risk Factors contained in our annual report on Form 10-K for the year ended December 31, 2004, 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. should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to our unaudited condensed consolidated balance sheets, statements of income, statements of cash flows and statement of partners capital.

This report on Form 10-Q should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2004.

Overview

We are a publicly traded limited partnership 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 in Alberta, Canada. We conduct our business through two regional business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. 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.

Recent Developments

Valero Acquisition

On July 1, 2005, we entered into a Sale and Purchase Agreement (the Purchase Agreement), with Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P. and Shore Terminals LLC (the Sellers), pursuant to which we agreed to acquire certain terminal and pipeline assets from the Sellers for an aggregate purchase price of $455.0 million. The assets being purchased consist of (i) the Martinez Terminal and Richmond Terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia Terminals and the Paulsboro, New Jersey Terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four truck terminals and storage in the U.S. Rocky Mountains.

The Martinez and Richmond Terminals have 4.1 million barrels of combined storage capacity and handle refined products, refinery blend stocks and crude oil. The terminals are connected to pipelines and to area refineries by pipelines and can also receive and deliver products by marine vessel or barge. The terminals also have truck racks for products delivery and receipt. The Richmond terminal has a rail spur for delivery and receipt of products.

The North Philadelphia Terminal, the South Philadelphia Terminal and the Paulsboro, New Jersey Terminal handle refined products and have a combined storage capacity of 3.2 million barrels. The terminals are connected to pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The 550-mile pipeline system, known as the West Pipeline System, consists of 550 miles of refined products pipeline extending from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. In addition, there are four products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels.

We expect to fund the acquisition on a permanent basis by issuing common units for approximately 60-65% of the price and debt securities for approximately 35-40% of the acquisition price. The purchase is subject to the receipt of regulatory approvals and is expected to close by October 1, 2005.

Also, in connection with the purchase, we received $700 million in financing commitments from Bank of America, N.A. and Lehman Brothers, Inc. These commitments include a new five-year $400 million secured revolving credit facility, which would partly fund the acquisition as well as repay and replace our existing U.S. and Canadian revolving credit facilities. These commitments also include a $300 million, 364-day secured term credit facility, which would only be used to fund the acquisition if permanent financing is not obtained by the acquisition closing date.

Purchase of Crude Oil and Contracts

On July 1, 2005, we purchased certain crude oil contracts and crude oil inventories for approximately $2.2 million plus contingent payments over the next three and one half years based on specified performance criteria. The assets were purchased by the Partnership s Pacific Marketing and Transportation (PMT) subsidiary.

Line 63 Crude Oil Release

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide induced by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through March 2006, we expect to incur an estimated total of $15.0 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. Through June 30, 2005, we had incurred approximately $11.5 million of the total expected oil release costs for work performed through such date.

We have a pollution liability insurance policy with a $2.0 million deductible, and the insurance carrier has acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. Although we believe we are entitled, subject to the $2.0 million deductible, to recover substantially all of our clean-up costs and third-party claims associated with the release, there is no absolute assurance that this will be the case. As of June 30, 2005, we have recovered $6.3 million from insurance and accrued a receivable of $6.7 million for insurance receipts we deem probable. As new information becomes available in future periods, our initial estimates of costs and recoveries may change.

We recorded $2.0 million in net costs in Line 63 oil release costs in the accompanying condensed consolidated statements of income for the six months ended June 30, 2005. The $2.0 million net oil release costs consist of $15.0 million of accrued costs relating to the release, net of insurance recovery of $6.3 and accrued insurance receipts of $6.7 million.

On April 18, 2005, we received the necessary approvals to begin the repair of Line 63, and Line 63 was returned to operation. During the time the pipeline was out of service, we transferred significant volumes of light crude oil, on a temporary basis, from Line 63 to Line 2000, to mitigate the impact on customers and limit the potential loss of revenue. We also asked our customers to shift volumes of OCS crude oil from Line 63 to Line 2000. We expect the permanent repair of Line 63 to be complete in the third quarter of 2005. We expensed $0.6 million, all in the second quarter, for the repair of Line 63 and expect to incur $1.2 million of Line 63 capital improvements in future periods.

On July 21, 2005, the California Public Utilities Commission (CPUC) approved our request to implement a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover our costs relating to this release together with other costs incurred or to be incurred as a result of problems caused by rain-induced earth movement and stream erosion. The surcharge was effective on August 1, 2005. We are required under the terms of the CPUC decision that approved the surcharge to substantiate in subsequent filings with the CPUC the actual costs incurred by us as a result of the Line 63 damage and our entitlement to the surcharge amounts received by us.

Sale of The Anschutz Corporation s Interest in the Partnership

On March 3, 2005, The Anschutz Corporation completed the sale of its 36.6% interest in the Partnership to LB Pacific, LP (LBP), an entity formed by Lehman Brothers Merchant Banking Group (LBMB). The acquisition by LBP (the LB Acquisition) included the purchase of a 100% ownership interest in Pacific Energy GP, Inc. (predecessor of Pacific Energy GP, LP), which owned (i) a 2% general partner interest in the Partnership and the incentive distribution rights, and (ii) 10,465,000 subordinated units of the Partnership representing a 34.6% limited partner interest. Immediately prior to the closing of the LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP, a Delaware limited partnership (together with its predecessors, the General Partner). The general partner of Pacific Energy GP, LP is Pacific Energy Management LLC, a Delaware limited liability company (PEM or the Managing General Partner), which is 100% owned by LBP. Immediately following the closing of the LB Acquisition, our General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of our General Partner to a limited partnership, our General Partner ceased to have a board of directors, and is now managed by PEM, its general partner. PEM has a board of directors (the Board of Directors or Board) that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of our General Partner and the Partnership. All of the officers and employees of our General Partner were transferred to the same positions with PEM, and the Board established the same committees as had been maintained by our General Partner prior to the LB Acquisition. PEM also adopted our General Partner s governance guidelines and its compensation structure and employee benefit plans and policies.

Pursuant to an Ancillary Agreement, LBP and The Anschutz Corporation reimbursed us $2.4 million, which represents the cost incurred by us in connection with a consent solicitation prepared and delivered to the holders of our 71/8% Senior Notes, due 2014 (the Senior Notes) to approve certain amendments to the indenture governing the Senior Notes, and for severance and other costs incurred in connection with the sale of our General Partner. We were required by generally accepted accounting principles to record $0.6 million as capitalized deferred financing costs and $1.8 million as an expense. The reimbursements were recorded as the General Partner s capital contribution.

On March 3, 2005, in connection with the change in control of our General Partner, all restricted units outstanding under the Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. As a result, we issued 99,583 common units and recorded a compensation expense of $3.1 million.

Because the LB Acquisition, together with other stock market activity, resulted in a change in ownership of more than 50% of the Partnership within a one year period, federal income tax laws require a modification to the Partnership s 2005 taxable income. The modification will result in a reduction in depreciation for 2005. The reduction in depreciation in 2005 will lead to additional depreciation becoming available for recognition in future years. Prior to the acquisition of assets from Valero L.P., we estimated that the amount of taxable income in 2005 would be approximately 50% to 60% of the cash distributions made to unitholders. For the period 2006 through 2008, prior to the acquisition of assets from Valero L.P., we estimated that taxable income would be less than 20% of the cash distributions expected to be made to unitholders. We have not yet updated these estimates to account for the acquisition of assets from Valero L.P. The modification of taxable income will not have any impact on the Partnership s consolidated financial statements.

Business Fundamentals

Pipeline Transportation

We generate pipeline transportation revenue by charging tariff rates for transporting crude oil on our common carrier pipelines. The fundamental items impacting our pipeline transportation revenue are the volume of crude oil, or throughput, that 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 or pipeline 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 tariff rates we charge on Line 2000 and the Line 63 system are regulated by 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 Federal Energy Regulatory Commission (FERC) or the Wyoming Public Service Commission, generally under a cost-of-service approach.

On July 1, 2005 we increased the tariff rates on our U.S. Rocky Mountain pipelines by 3.6% based on the FERC index adjustment. On May 1, 2005 we increased the tariff rates on our Line 2000 by approximately 4.8%. Effective November 1, 2004, we increased the tariff rates on our Line 63 system by 9.5%. This increase was the first for Line 63 since 2001. On May 1, 2004, we increased the tariff rates on Line 2000 by approximately 6%. This index is reviewed annually. These tariff rate increases partially mitigate the impact of declining throughput on our West Coast 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 Outer Continental Shelf (OCS), total production is generally declining.

In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and in 2004 we completed the acquisition of the Rangeland system, giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any long term U.S. Rocky Mountain production declines and meet growing demand in the U.S. Rocky Mountain region. It appears in recent months that production in the U.S. Rocky Mountains may be increasing with the increased amount of natural gas related drilling, which results in increased volumes of crude oil and condensate. We believe, however, that the longer term production of crude oil will resume its historical decline.

Storage and Distribution

We provide storage and distribution services to refineries in the Los Angeles Basin through our Pacific Terminals (PT) storage and distribution system. 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 storage capacity for other dark products is less stable, 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 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 and plan to convert a second tank in 2006.

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

Throughput on our Rangeland system, which was acquired in the second quarter of 2004, varies with many of the same factors described in Pipeline Transportation above. In addition, following completion of our Edmonton initiation station, scheduled for completion in the fourth quarter of 2005, throughput will vary with our success in attracting new supplies of synthetic crude oil to our system.

We are making significant changes to the revenue-generating capability of the Rangeland system by (i) combining and fully integrating all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, (ii) establishing connections with other pipelines, thereby expanding the throughput capacity of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta. The development of the new receiving terminal and pump station, which will provide access to synthetic and other types of Canadian crude oil, continues to progress. Construction of this facility, together with additional tanks along the pipeline corridor, is expected to be complete in the fourth quarter of 2005.

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

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

Effective December 1, 2004, we increased the location differentials on the Rangeland pipeline by an average of 10.8%.

Gathering and Blending

Through our PMT subsidiary, we purchase, gather, blend and resell crude oil in California s San Joaquin Valley and in the Rocky Mountain area. In California, our PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our pipeline transportation business. The California gathering network effectively extends our pipeline network to capture supplies of crude oil for transportation on our trunk pipelines to Los Angeles that might not otherwise be shipped through our pipelines. In the U.S. and Canadian Rocky Mountain area, PMT facilitates transportation on our Canadian and U.S. Rocky Mountain pipelines by purchasing crude oil from Canada and the U.S. Rocky Mountain region for resale in the PADD IV market place.

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 that PMT buys for use in its blending operations, and the price of the blended crude oil it sells. Costs and sales prices are generally impacted by crude oil prices, as well as by local supply and demand forces, including regulations affecting refined product specifications. Second, it varies with the price differential between crude oil purchased on one price basis and sold on 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.

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. We also intend to expand, beyond our acquisition of assets from Valero L.P., principally by acquisition, into the refined product and natural gas storage and transportation businesses. We expect the acquisitions and new projects to be accretive to our cash flow and complement our existing businesses. 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% 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 do, however, vary with throughput, the most material being the cost of power used to run pump stations along our pipelines. Major maintenance costs can also vary depending on a particular asset s age and/or 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, and repairs caused by severe weather as we have experienced in California and Alberta, Canada this year.

We do not have any employees, except in Canada. Our Managing General Partner provides employees to conduct our U.S. operations. We and our Managing General Partner collectively employ approximately 315 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement. Our Managing General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our Managing General Partner are charged to us. Please read Note 3 Related Party Transactions in the footnotes to the condensed consolidated financial statement.

Impact of Foreign Exchange Rates

Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The reported cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary in U.S. dollar terms based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries underlying operating results. In addition, the amount of monies we repatriate from Canada will vary with fluctuations in currency exchange rates and may impact the cash available for distribution to our unitholders.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet, as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 1, Significant Accounting Policies, to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2004) 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. Additionally, we must determine whether an acquisition is considered to be a business or a set of net assets because excess purchase price can only be allocated to goodwill in a business combination. The valuation of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilized in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation 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 may use outside environmental consultants to assist us in making these estimates. We also are required to estimate the amount of any probable recoveries, including insurance recoveries. In addition, generally accepted accounting principles require us to establish liabilities for the costs of asset retirement obligations when 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, in order to determine whether to accrue for a future expense. We use outside regulatory lawyers and financial experts to assist us in these assessments.

- Our inventory of crude oil for our PMT gathering and blending operations, our Canadian operations and any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines is carried on our books at the lower of cost or market value, unless it is hedged, in which case it is carried at market. On any unhedged portion, we are exposed to the potential for a write-down to market value.

Results of Operations

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

Oil release on Line 63. On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS s Line 63 as a result of a landslide induced by heavy rainfall in northern Los Angeles County. We were able to recover approximately 1,800 barrels of the released oil as part of the clean-up operations. As discussed in Recent Developments above, for the six months ended June 30, 2005, we accrued $15.0 million to remediate the area, together with related costs. The $2.0 million net oil release costs recorded in the first quarter of 2005 consists of the $15.0 million of accrued costs relating to the release, net of insurance recovery of $6.3 million and accrued insurance receipt of $6.7 million. The discussion in Recent Developments describes the nature of these estimates and the potential for these estimates to increase or decrease in future periods.

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

Transaction costs. Pursuant to an Ancillary Agreement, LBP and The Anschutz Corporation reimbursed us $2.4 million for the cost incurred in connection with a consent solicitation prepared and delivered to the holders of our Senior Notes to approve certain amendments to the indenture governing

the Senior Notes and for severance and other costs incurred in connection with the sale of our General Partner. We were required by generally accepted accounting principles to record $0.6 million as capitalized deferred financing costs and $1.8 million as an expense, both in the first quarter of 2005. The reimbursements were recorded as a partner s capital contribution.

Write-off of deferred financing cost and interest rate swap termination expense. In the second quarter of 2004, we recorded an expense related to the unamortized portion of deferred financing cost of $2.3 million for our term loan, which was repaid in 2004, and incurred $0.6 million of expense to terminate related interest rate swaps.

Three Months Ended June 30, 2005 Compared to Three Months Ended June 30, 2004

Summary

Net income for the three months ended June 30, 2005 was $12.2 million, or $0.40 per diluted limited partner unit, compared to $9.1 million, or $0.30 per diluted limited partner unit, for the three months ended June 30, 2004.

Net income for the three months ended June 30, 2005 includes a full quarter of operations of the Rangeland system compared to 2004. The Rangeland system was acquired on May 11, 2004 and expanded by the acquisition of the MAPL pipeline on June 30, 2004.

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

	Three Months Ended June 30, 2005 (In thousands)	**2004**	**Change**	**Percent**
Net income	$ 12,220	$ 9,128	$ 3,092	34 %
Add: Write-off of deferred financing cost and interest rate swap termination expense		2,901	(2,901)	
	$ 12,220	$ 12,029	$ 191	2 %
Diluted weighted average limited partner units	29,742	29,632	110	1 %

The results of operations for the three months end June 30, 2005, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) increased pipeline volumes in the Rocky Mountains, (ii) higher tank utilization and additional storage capacity for Pacific Terminals (a 72,000 barrel idle tank was put into service during the third quarter of 2004) and, (iii) the benefit of a full quarter of operations for the Rangeland system, which was acquired in May 2004. These increases were offset by lower pipeline volumes on the West Coast and by $1.4 million of pipeline repair and maintenance costs associated with earth movement and stream erosion due to heavy rainfall in Southern California during the early part of 2005.

Segment Information

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

West Coast	Three Months Ended June 30, 2005 (In thousands)	2004	Change	Percent
Operating income	$ 12,405	$ 14,092	$ (1,687)	(12)%
Operating data:				
Pipeline throughput (bpd)	120.0	139.5	(19.5)	(14)%

For the three months ended June 30, 2005, operating income was $12.4 million, compared to $14.1 million for the three months ended June 30, 2004. West Coast pipeline volumes for the three months ended June 30, 2005 were approximately 14% lower than the second quarter of 2004 because in 2005 (i) one shipper began moving additional volumes north to San Francisco, reducing the supply of crude oil available to be moved south to Los Angeles, (ii) refinery maintenance in the L.A. Basin resulted in lower volumes moving south to Los Angeles, (iii) there was lower OCS production due to maintenance activities, and (iv) because of the natural production decline of San Joaquin Valley crude and OCS crude oil. In addition, although we were able to shift significant volumes of crude oil from Line 63 to Line 2000 during the period Line 63 was out of service because of the landslide and associated break in Line 63, some volumes were lost during this period as customers sought to ensure their supply. Line 63 was out of service from March 23, 2005 through April 25, 2005. These adverse conditions were partially offset by higher storage revenues on our Pacific Terminals storage and distribution system resulting from increased tank utilization and additional tank storage capacity being made available.

Rocky Mountains	Three Months Ended June 30, 2005 (In thousands)	2004	Change	Percent
Operating income	$ 8,962	$ 5,716	$ 3,246	57 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	23.1	21.2	1.9	9 %
Sundre South	39.7	48.8	(9.1)	(19)%
Western Corridor system	22.2	19.8	2.4	12 %
Salt Lake City Core system	124.4	119.2	5.2	4 %
Frontier pipeline	51.3	50.0	1.3	3 %

For the three months ended June 30, 2005, operating income was $9.0 million, compared to $5.7 million for the three months ended June 30, 2004. The increase included a full quarter s results of the Rangeland system, which was acquired on May 11, 2004 and expanded by the acquisition of the MAPL pipeline on June 30, 2004. In addition, increased market share for pipeline shipments of crude oil to Billings, Montana and increased demand by the Salt Lake City, Utah refineries helped drive higher pipeline volumes on the U.S. Rocky Mountain systems. Frontier pipeline volumes increased in the second quarter of 2005 over the same period in 2004, because a connecting carrier increased downstream capacity beginning in June 2005.

Statement of Income Discussion and Analysis

Revenues	**Three Months Ended June 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Pipeline transportation revenue	$ 27,747	$ 26,992	$ 755	3 %
Storage and distribution revenue	10,870	9,259	1,611	17 %
Pipeline buy/sell transportation revenue	8,116	3,690	4,426	120 %
Crude oil sales, net of purchases:				
Crude oil sales	128,484	100,438	28,046	28 %
Crude oil purchases	(122,442)	(94,382)	28,060	30 %
Crude oil sales, net of purchases	6,042	6,056	(14)	(1)%
Net revenue	$ 52,775	$ 45,997	$ 6,778	15 %

Increased pipeline transportation revenues were realized by our U.S. Rocky Mountain pipelines. Volumes on the U.S. Rocky Mountain pipelines were higher due to increased demand by refineries in Billings, Montana, Casper, Wyoming and Salt Lake City, Utah area refineries. Our West Coast pipelines had lower revenues compared to the prior year for several reasons, as noted above. The reduction in volumes on our West Coast pipeline was partially offset by increased tariff rates that were implemented in the fourth quarter of 2004 on Line 63 and in the second quarter of 2005 for Line 2000.

Storage and distribution revenue is higher than the prior year due to increased tank utilization and additional storage capacity being available (an idle 72,000 barrel tank was put back into service during the third quarter of 2004).

Pipeline buy/sell transportation revenues of $8.1 million reflect a full quarter s revenues of the Rangeland system compared to 2004, which included revenue of the Rangeland system from the date it was acquired on May 11, 2004.

Net crude oil sales for the three months ended June 30, 2005 were essentially unchanged compared to the three months period ended June 30, 2004. We consider this activity to be complementary to our pipeline transportation operations.

Expenses	**Three Months Ended June 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Operating expenses	$ 25,292	$ 20,867	$ 4,425	21 %
General and administrative expense	3,700	3,636	64	2 %
Depreciation and amortization expense	6,606	5,713	893	16 %
	$ 35,598	$ 30,216	$ 5,382	18 %

The increase in operating expense was related primarily to the acquisition of the Rangeland system on May 11, 2004. Operating expenses in the West Coast were also higher as a result of $1.4 million of unscheduled repairs and maintenance associated with earth movement and stream erosion problems caused by heavy rainfall in Southern California during the early part of 2005.

General and administrative expense is consistent with the comparative period in the prior year. Increases in general and administrative expense associated with a full quarter s operation of the Rangeland system in the 2005 quarter and corporate development activities were offset by the absence of an expense for the long term incentive plan.

The increase in depreciation and amortization includes $1.0 million for additional depreciation on the Rangeland system. These increases were partly offset by lower depreciation on other assets reflecting assets that have now been fully depreciated.

Other Income and Expense	**Three Months Ended June 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Share of net income of Frontier	$ 490	$ 391	$ 99	25 %
Interest expense	$ 5,844	$ 4,383	$ 1,461	33 %
Write-off of deferred financing cost and interest rate swap termination expense	$	$ 2,901	$ 2,901	
Other income	$ 540	$ 226	$ 314	139 %
Income tax expense (benefit)	$ 143	$ (14)	$ 157	

The increase in our share of Frontier s net income was mainly attributable to increased pipeline volumes as a result of an increase in pipeline capacity due to an agreement with a connecting carrier.

The increase in interest expense was due to additional borrowings incurred to partially fund the acquisition of the Rangeland system. Our weighted average borrowings during the three months ended June 30, 2005 were $366 million compared to $273 million in the corresponding period in 2004. In addition, floating interest rates were higher in 2005, which resulted in a weighted average interest rate of 6.4% for the three months ended June 30, 2005 compared to a weighted average interest rate of 6.0% for the corresponding period in 2004.

The write-off of deferred financing cost and interest rate swap termination expense are discussed in Results of Operations above.

Other income of $0.5 million for the period ended June 30, 2005 was $0.3 million greater than the corresponding period in 2004 due to increased interest income and other items.

The increase in income tax expense for the three months ended June 30, 2005 relates to the income of the Rangeland system acquired in the middle of the second quarter of 2004. Our Canadian subsidiaries are taxable entities, and certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. Additionally, we recorded deferred tax liabilities in connection with the purchase of our Canadian subsidiaries, which we recognize into earnings in the respective future tax periods.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Summary

Net income for the six months ended June 30, 2005 was $15.6 million, or $0.58 per diluted limited partner unit, compared to $17.2 million, or $0.62 per diluted limited partner unit, for the six months ended June 30, 2004.

Net income for the six months ended June 30, 2005 includes six months of operations of the Rangeland system compared to 2004. The Rangeland system was acquired on May 11, 2004 and expanded by the acquisition of the MAPL pipeline on June 30, 2004.

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

	Six Months Ended June 30, 2005 (In thousands)	2004	Change	Percent
Net income	$ 15,641	$ 17,205	$ (1,564)	(9)%
Add:Line 63 oil release costs	2,000		2,000	
Accelerated long-term incentive compensation expense	3,115		3,115	
Transaction costs	1,807		1,807	
Write-off of deferred financing cost and interest rate swap termination expense		2,901	(2,901)	
	$ 22,563	$ 20,106	$ 2,457	12 %
Diluted weighted average limited partner units	29,708	27,402	2,306	8 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Rangeland system acquired in May 2004, (ii) higher pipeline transportation revenues on the Rocky Mountain pipelines, and (iii) higher storage and terminaling revenues on our Pacific Terminal systems. These increases were partially offset by (i) significantly lower gathering and blending margins, which were below average in the six months ended June 30, 2005 and above average in the six months ended June 30, 2004, and (ii) unscheduled repairs and maintenance associated with earth movement and stream erosion problems caused by heavy rainfall in Southern California during the early part of 2005. The lower margins on our West Coast gathering and blending activities were due to competitive pricing pressures as a result of cheaper foreign crude entering the West Coast markets. We consider this gathering and blending activity to be complementary to our pipeline transportation operations. There were 29.7 million weighted average limited partner units outstanding in the six months ended June 30, 2005, approximately 8% more limited partner units than the 27.4 million weighted average units outstanding in the six months ended June 30, 2004, primarily due to the sale of additional common units to partially fund the acquisition of the Rangeland system, including the MAPL pipeline.

Segment Information

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

West Coast	**Six Months Ended June 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Operating income	$ 22,149	$ 26,347	$ (4,198)	(16)%
Add: Line 63 oil release cost	2,000		2,000	
	$ 24,149	$ 26,347	$ (2,198)	(8)%
Operating data:				
Pipeline throughput (bpd)	129.2	136.6	(7.4)	(5)%

For the six months ended June 30, 2005, operating income excluding the effect of the $2.0 million expense for the Line 63 oil release was $24.1 million, compared to $26.3 million for the six months ended June 30, 2004. West Coast pipeline volumes for the six months ended June 30, 2005 were approximately 5% lower than the same period in 2004. During the first half of 2005, volumes were impacted by Los Angeles area refinery maintenance and lower San Joaquin Valley and OCS production, resulting in lower volumes moving south to Los Angeles. There were $2.0 million of unscheduled repairs and maintenance associated with earth movement and stream erosion problems at various locations along both Line 63 and Line 2000, caused by heavy rainfall in Southern California. PMT gathering and blending margins were also lower in 2005 due to pricing pressures from discounted crude oil imports and margins on one particular contract which expired on March 31, 2005. We consider this gathering and blending activity to be complementary to our pipeline transportation operations. The revenue effect of lower volumes was offset by incremental revenue from increased tariffs on Line 63 beginning November 1, 2004, and on Line 2000 beginning May 1, 2005. Additionally, storage and distribution revenues were higher during the six months ended June 2005, due to higher rates of tank utilization and 72,000 barrels of additional tank capacity being made available as a result of an idle tank being put into service in the third quarter of 2004.

Rocky Mountains	**Six Months Ended June 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 18,539	$ 9,357	$ 9,182	98 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	22.2	21.2	1.0	5 %
Sundre South	43.9	48.8	(4.9)	(10)%
Western Corridor system	22.4	18.0	4.4	24 %
Salt Lake City Core system	116.7	113.0	3.7	3 %
Frontier pipeline	44.8	47.0	(2.2)	(5)%

For the six months ended June 30, 2005, operating income was $18.5 million, compared to $9.4 million for the six months ended June 30, 2004. The increase included the results of the Rangeland system, which was acquired on May 11, 2004. In addition, increased market share for pipeline shipments of crude oil to Billings, Montana, and increased demand by the Salt Lake City, Utah, refineries, helped drive higher pipeline volumes on the U.S. Rocky Mountain systems other than Frontier pipeline. Frontier pipeline volumes in 2005 were affected by a shortage of synthetic crude oil supply caused by a fire at a Suncor Energy, Inc. facility in December 2004. Shippers have now replaced these volumes with other types of crude oil and volumes returned to normal levels in the second quarter of this year.

Statement of Income Discussion and Analysis

Revenues	**Six Months Ended June 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Pipeline transportation revenue	$ 55,784	$ 51,719	$ 4,065	8 %
Storage and distribution revenue	21,192	19,382	1,810	9 %
Pipeline buy/sell transportation revenue	17,222	3,690	13,532	
Crude oil sales, net of purchases:				
Crude oil sales	244,657	186,365	58,292	31 %
Crude oil purchases	(236,833)	(175,497)	61,336	35 %
Crude oil sales, net of purchases	7,824	10,868	(3,044)	(28)%
Net revenue	$ 102,022	$ 85,659	$ 16,363	19 %

Increased pipeline transportation revenues were realized by our U.S. Rocky Mountain pipelines. Volumes on the U.S. Rocky Mountain pipelines were higher due to increased demand by refineries in Billings, Montana, Casper, Wyoming and Salt Lake City, Utah area refineries. The revenue effect of lower volumes on the West Coast pipelines was offset by higher tariffs.

Storage and distribution revenues were higher than the same period in 2004 due to higher rates of tank utilization and increased capacity being made available as a result of a 72,000 barrel idle tank being put into operation during the third quarter of 2004.

The increase in pipeline buy/sell transportation revenues of $13.5 million reflects a full six months of operations of the Rangeland system, which was acquired on May 11, 2004.

The decrease in net crude oil sales for the six months ended June 30, 2005 was primarily the result of lower margin blending activities in our West Coast operations, particularly due to competitive pricing pressures from cheaper foreign crude entering the West Coast markets. Additionally, margins on one particular contract declined as the difference between purchases made on a WTI price basis deviated from historical norms over the period from September 2004 through March 2005. This contract expired on March 31, 2005. Higher oil prices increased gross sales and purchases values. We consider this gathering and blending activity to be complementary to our pipeline transportation operations.

Expenses	**Six Months Ended June 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Operating expenses	$ 47,046	$ 39,784	$ 7,262	18 %
Line 63 oil release costs	2,000		2,000	
General and administrative expense	8,872	7,490	1,382	18 %
Transaction costs	1,807		1,807	
Accelerated long-term incentive plan compensation expense	3,115		3,115	
Depreciation and amortization expense	13,135	10,955	2,180	20 %
	$ 75,975	$ 58,229	$ 17,746	30 %

The increase in operating expense was related primarily to the acquisition of the Rangeland system on May 11, 2004. Operating expenses in the West Coast were also higher as a result of $2.0 million of unscheduled repairs and maintenance and expenses on Line 2000 and Line 63 resulting from earth movements and creek washouts caused by recent heavy rains.

The Line 63 oil release costs are discussed in Recent Developments above.

The increase in general and administrative expense was associated with the integration and operation of the Rangeland acquisition and certain expensed costs for the Pier 400 project (see Capital Requirements below for a discussion of the Pier 400 Project). These items were not applicable in the corresponding period of 2004. In addition, we incurred more costs for acquisition evaluations in 2005. These increases were partly offset by reduced cost for the Long Term Incentive Plan included in general and administrative expense.

Transaction costs are discussed in Recent Developments above.

On March 3, 2005, in connection with the change in control of the General Partner, all restricted units outstanding under the Long-term Incentive Plan immediately vested. For the six months ended June 30, 2005, we recognized $3.1 million in compensation expense as a result.

The increase in depreciation and amortization includes $2.5 million for depreciation on the Rangeland system. These increases were partly offset by lower depreciation on other assets reflecting assets that have now been fully depreciated.

Other Income and Expense	Six Months Ended June 30, 2005	2004	Change	Percent
(In thousands)				
Share of net income of Frontier	$ 847	$ 784	$ 63	8 %
Interest expense	$ 11,442	$ 8,509	$ 2,933	34 %
Write-off of deferred financing cost and interest rate swap termination expense	$	$ 2,901	$ 2,901	
Other income	$ 893	$ 387	$ 506	131 %
Income tax expense (benefit)	$ 704	$ (14)	$ 718	

The increase in our share of Frontier s net income was mainly attributable to increased pipeline volumes in the second quarter as a result of a connecting carrier increasing its capacity.

The increase in interest expense was due to borrowings incurred to partially fund the acquisition of the Rangeland system. Our weighted average borrowings during the six months ended June 30, 2005 were $362 million compared to $289 million in the corresponding period in 2004. In addition, floating interest rates were higher in 2005, which resulted in a weighted average interest rate of 6.3% for the period ended June 30, 2005 compared to a weighted average interest rate of 5.7% for the corresponding period in 2004.

Other income of $0.9 million for the period ended June 30, 2005 was $0.5 million greater than the corresponding period in 2004 due to increased interest income and other items.

The increase in income tax expense for the six months ended June 30, 2005 relates to the income of the Rangeland system acquired on May 11, 2004. Our Canadian subsidiaries are taxable entities and certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. Additionally, we recorded deferred tax liabilities in connection with the purchase of our Canadian subsidiaries, which we recognize into earnings in the respective future tax periods.

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, our remaining costs for the Line 63 oil release remediation and related costs, and our anticipated sustaining capital expenditures in the next three years.

In connection with the acquisition of certain assets from Valero, L.P., we plan to issue $275 $300 million of additional common units, issue $150 million of additional senior unsecured notes and replace our revolving credit facilities, which would otherwise mature in mid-2007. See Note 9 Subsequent Events to the accompanying condensed consolidated financial statements.

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

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

	Six Months Ended June 30, 2005	2004	Change
	(In thousands) (unaudited)		
Net cash provided by operating activities	$ 46,218	$ 29,265	$ 16,953
Net cash used in investing activities	(9,975)	(146,946)	136,971
Net cash provided by (used in) financing activities	(27,549)	129,843	(157,392)

Net cash provided by operating activities

The increase in the net cash from operating activities of $17.0 million, or 58%, was primarily the result of a decrease in cash used for working capital.

Net cash from operating activities for the six months ended June 30, 2005 was increased by approximately $15.0 million by working capital changes. Increases in accounts payable and other accrued liabilities and accrued crude oil purchases more than offset an increase in crude oil sales receivables, transportation and storage receivables, and insurance proceeds receivable.

Net cash used in investing activities

Capital expenditures were $9.9 million in the first half of 2005, of which $0.8 million related to sustaining capital projects, $3.2 million related to transition projects, $3.7 million related to expansion and $2.2 million was for our continued development of the Pier 400 Project. The amount of cash used in investing activities in 2004 relates primarily to our acquisition and development activities. The 2004 period includes $139.1 million related to the acquisition of the Rangeland system, including the MAPL pipeline. Capital expenditures for the six months ended June 30, 2004 were $7.9 million of which $0.7 million related to sustaining capital projects, $0.8 million related to the transition of the Pacific Terminals storage and distribution system, $4.6 million related to expansion and $1.8 million was for development of the Pier 400 Project.

Net cash provided by and used in financing activities

Cash provided by financing activities for the six months ended June 30, 2005 include distributions of $30.7 million which were made to the limited partners and the General Partner. Additionally, TAC and LBP contributed $2.4 million to reimburse us for certain costs incurred in connection with the LB Acquisition. We also received $2.0 million in net proceeds from our credit facilities in the six months ended June 30, 2005. The amount of cash provided by financing activities in 2004 of $129.8 million includes (i) net proceeds of $128.6 million from our equity offerings completed in March and April, 2004, which were used principally to partly fund our acquisition of the Rangeland system, (ii) $241.1 million net proceeds from the offering of our Senior Notes, which were used in part to repay our $225 million term loan, (iii) net proceeds of $12.7 million under our revolving credit facilities, and (iv) $27.1 million in distributions to the limited and general partner interests.

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 for our existing operations of $57 million for 2005, including $10 million for the Pier 400 Project, $32 million for expansion projects, $10 million relating to the transition of the Rangeland system, $2 million for other transition capital projects, and $3 million for sustaining capital projects.

Pier 400

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

We initiated the environmental review and permitting for the Pier 400 project in June 2004 and expect to have the permits necessary for construction to begin in the second quarter of 2006. We entered into a project development agreement with two subsidiaries of Valero Energy Corporation that defines the facilities that we are to construct in the POLA. We and Valero Energy Corporation have also signed a terminaling services agreement with a 30-year, 50,000 bpd volume commitment from Valero Energy Corporation to support the terminal. These agreements are subject to the satisfaction of various conditions, including the execution of additional project related agreements and the achievement of certain project milestones, some of which have not been satisfied. We are negotiating these additional agreements and an extension of the project milestones with Valero, and we expect to reach an agreement.

Final construction of the Pier 400 Project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approval, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. A final decision to proceed is expected to be made in the first quarter of 2006. We expect construction of the Pier 400 terminal to be completed and placed in service in late 2007.

We have capitalized approximately $12.7 million on the Pier 400 project through June 30, 2005, including $2.2 million for the six months ended June 30, 2005. These expenditures include $6.3 million for emission reduction credits, an asset that is re-saleable if the project does not proceed. We anticipate funding pre-construction costs through early-2006 from our revolving credit facility. 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.

Debt Obligations

At June 30, 2005, our debt obligations include: (i) $53.0 million on our senior secured U.S. revolving credit facility, (ii) Cdn$65.0 million (U.S.$53.0 million) on our senior secured Canadian revolving credit facility, (iii) $249.5 million on our Senior Notes, and (iv) Cdn$4.5 million (U.S.$3.7 million) payable to the seller of the MAPL assets. For further discussion of these debt obligations see Note 4 Long-term Debt to the accompanying condensed consolidated financial statements.

As of June 30, 2005, $80 million of undrawn credit was available under the senior secured U.S. revolving credit facility and Cdn$14 million of undrawn credit was available under the senior secured Canadian revolving credit facility. With the consent of the administrative agent under the U.S. revolving credit facility, we can increase credit availability under the U.S. credit facility by up to an additional $67 million, based upon pro-forma EBITDA from future acquisitions.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Accounting Pronouncements

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

On March 30, 2005 the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations (FIN 47)*, to clarify the term *conditional asset retirement obligation* as that term is used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. The Interpretation also clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for the Partnership no later than the end of fiscal years ending after December 15, 2005. The Partnership is in the process of determining the impact of FIN 47 on its consolidated financial statements.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and crude oil price risk. Debt we incur under our credit facilities bears variable interest at the applicable base or prime rate, a rate based on LIBOR or a rate based on Canadian Bankers Acceptances. We have used and will continue to use from time to time derivative instruments to hedge our exposure to variable interest rates. In addition, we have entered into swap agreements to convert a portion of our fixed rate Senior Notes into floating rate debt based on LIBOR.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our 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. The fair market values of derivative instruments are included in Other Assets, net in the accompanying consolidated balance sheets. In our gathering and blending 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 the fair value hedge of crude oil inventory are recognized in net income. For the six months ended June 30, 2005 and 2004, crude oil sales, net of purchases were net of $0.5 million in losses in each period, reflecting changes in the fair value of derivative instruments in our gathering and blending operations. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. In addition, changes in the fair value of our derivative instruments related to the forecasted sale of crude oil, which qualify as cash flow hedges for accounting purposes, are deferred and reflected in accumulated other comprehensive income, a component of partners capital, until the related revenue is recognized in the consolidated statements of income. We expect to reclassify a net amount of $1.0 million of existing gains and losses into earnings over the next 12 months. For existing hedges, the maximum length of time over which we are hedging our exposure to future cash flows for forecasted transactions is six months. As of June 30, 2005, $1.0 million relating to the changes in the fair value of derivative instruments was included in accumulated other comprehensive income.

In connection with the issuance of the Senior Notes, we entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 71/8% 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 on June 15, 2014 and are callable at the same dates and terms as the Senior Notes. We 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, which are expected to be offsetting to changes in the fair value of the interest swaps, are recorded into earnings each period. At June 30, 2005 we recorded an increase of $3.5 million in the fair value of interest rate swaps with an equal offsetting entry to the $80.0 million of Senior Notes. As of June 30, 2005, we assessed the hedge effectiveness of this interest rate swap and noted that no gain or loss from measuring ineffectiveness was required to be recognized.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the $80 million interest swap on the Senior Notes are based on variable rates. If the LIBOR or Canadian Bankers Acceptance discount rates were to increase 1.0% for the remainder of 2005 as compared to the rate at December 31, 2004, our interest expense for the remainder of 2005 would increase $0.9 million based on our outstanding debt at June 30, 2005.

Fair Value of Financial Instruments

The carrying amount and fair values of financial instruments are as follows:

	June 30, 2005		December 31, 2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Crude oil hedging futures	$ 1,078	$ 1,078	$ 400	$ 400
Fair value interest rate swaps	3,528	3,528	2,693	2,693
Long-term debt	359,209	369,630	357,163	373,265

As of June 30, 2005 and December 31, 2004, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the revolving credit facilities approximate fair value primarily because the interest rates fluctuate with prevailing market rates. The interest rate on the Senior Notes is fixed and the fair value is determined from a broker s price quote at June 30, 2005 and December 31, 2004.

The carrying amount of derivative financial instruments represents the fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our fair values of crude oil hedging futures are based on Reuters quoted market prices on the NYMEX. Interest rate swaps fair values are based on the prevailing market price at which the positions could be liquidated.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

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

Based on their evaluation as of June 30, 2005, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended June 30, 2005 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 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 10.1		Sale and Purchase Agreement dated July 1, 2005, by and among Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P., Shore Terminals LLC and Pacific Energy Group LLC.
* Exhibit 31.1		Certification of Principal Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
* Exhibit 31.2		Certification of Principal Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
Exhibit 32.1		Certification of Chief Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
Exhibit 32.2		Certification of Chief Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

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* Filed herewith.

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

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SIGNATURES

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

PACIFIC ENERGY PARTNERS, L.P.
By: **PACIFIC ENERGY GP, LP, its General Partner**
By: **PACIFIC ENERGY MANAGEMENT LLC, its General Partner**

By: /s/ IRVIN TOOLE, JR.
Irvin Toole, Jr.
President, Chief Executive Officer and Director
(Principal Executive Officer)
August 2, 2005

By: /s/ GERALD A. TYWONIUK
Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer)
August 2, 2005

EXHIBIT INDEX

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Exhibit 32.2	Certification of Chief Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

* Filed herewith.

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