PACIFIC ENERGY PARTNERS LP
Form 10-Q
May 10, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2006

OR

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

For the transition period from to

Commission File Number 1-313345

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)

None

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

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

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

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

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

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

Class	**Outstanding at April 30, 2006**
Common Units	31,457,782
Subordinated Units	7,848,750

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.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2006 (in thousands)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,944	$ 18,064
Crude oil sales receivable	108,331	95,952
Transportation and storage accounts receivable	25,910	30,100
Canadian goods and services tax receivable	6,478	8,738
Insurance proceeds receivable	7,440	9,052
Due from related parties	229	
Crude oil and refined products inventory	36,391	20,192
Prepaid expenses	5,672	7,489
Other	3,791	2,528
Total current assets	206,186	192,115
Property and equipment, net	1,205,642	1,185,534
Intangible assets, net	68,426	69,180
Investment in Frontier	8,089	8,156
Other assets, net	17,907	21,467
	$ 1,506,250	$ 1,476,452
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,425	$ 43,859
Accrued crude oil purchases	113,182	96,651
Line 63 oil release reserve	2,787	4,448
Accrued interest	6,553	4,929
Other	5,050	6,300
Total current liabilities	160,997	156,187
Senior notes and credit facilities, net	600,985	565,632
Deferred income taxes	35,631	35,771
Environmental liabilities	16,671	16,617
Other liabilities	3,762	4,006
Total liabilities	818,046	778,213
Commitments and contingencies (note 4)		
Partners capital:		
Common unitholders (31,457,782 and 31,448,931 units outstanding at March 31, 2006 and December 31, 2005, respectively)	636,710	644,589
Subordinated unitholders (7,848,750 units outstanding at March 31, 2006 and December 31, 2005)	22,725	24,758
General Partner interest	12,326	12,535
Undistributed employee long-term incentive compensation	41	
Accumulated other comprehensive income	16,402	16,357
Net partners capital	688,204	698,239
	$ 1,506,250	$ 1,476,452

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in thousands, except per unit amounts)	
Revenues:		
Pipeline transportation revenue	$ 33,857	$ 28,037
Storage and terminaling revenue	20,086	10,322
Pipeline buy/sell transportation revenue	9,699	9,106
Crude oil sales, net of purchases of $256,319 and $114,391 for the three months ended March 31, 2006 and 2005	6,809	1,782
	70,451	49,247
Costs and Expenses:		
Operating (which excludes $586 of compensation expense for 2005 reported in accelerated long-term incentive plan compensation expense)	33,419	21,754
General and administrative (which excludes $2,529 of compensation expense for 2005 reported in accelerated long-term incentive plan compensation expense)	6,873	5,172
Accelerated long-term incentive plan compensation expense		3,115
Line 63 oil release costs		2,000
Transaction costs		1,807
Depreciation and amortization	10,002	6,529
	50,294	40,377
Share of net income of Frontier	398	357
Operating income	20,555	9,227
Interest expense	(9,088)	(5,598)
Interest and other income	443	353
Income before income taxes	11,910	3,982
Income tax (expense) benefit:		
Current	(394)	(732)
Deferred	98	171
	(296)	(561)
Net income	$ 11,614	$ 3,421
Net income (loss) for the general partner interest	$ (19)	$ (1,702)
Net income for the limited partner interests	$ 11,633	$ 5,123
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.17
Weighted average limited partner units outstanding:		
Basic	39,301	29,655
Diluted	39,313	29,720

See accompanying notes to condensed consolidated financial statements.

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

	Limited Partner Units		Limited Partner Amounts		General Partner	Undistributed Employee Long-Term Incentive	Accumulated Other Comprehensive	
	Common	Subordinated	Common	Subordinated	Interest	Compensation	Income	Total
	(in thousands)							
Balance, December 31, 2005	31,449	7,849	$ 644,589	$ 24,758	$ 12,535	$	$ 16,357	$ 698,239
Net income			9,310	2,323	(19)			11,614
Distribution to partners			(17,454)	(4,356)	(706)			(22,516)
Employee compensation under LB Pacific, LP option plan					511			511
Employee compensation under long-term incentive plan						356		356
Issuance of common units pursuant to long-term incentive plan	9		265		5	(315)		(45)
Foreign currency translation adjustment							(269)	(269)
Change in fair value of crude oil and foreign currency hedging contracts							314	314
Balance, March 31, 2006	31,458	7,849	$ 636,710	$ 22,725	$ 12,326	$ 41	$ 16,402	$ 688,204

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Net income	$ 11,614	$ 3,421
Change in fair value of crude oil hedging derivatives	260	(1,132)
Change in fair value of foreign currency hedging derivatives	54	
Change in foreign currency translation adjustment	(269)	(537)
Comprehensive income	$ 11,659	$ 1,752

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2006	2005
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 11,614	$ 3,421
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,002	6,529
Amortization of debt issue costs	606	459
Non-cash portion of employee compensation under long-term incentive plan	356	2,886
Non-cash employee compensation under the LB Pacific, LP option plan	511	
Deferred tax expense (benefit)	(98)	(171)
Share of net income of Frontier	(398)	(357)
Distributions from Frontier, net	422	
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(12,305)	(23,327)
Transportation and storage accounts receivable	4,195	(1,832)
Insurance proceeds receivable	1,612	(11,496)
Crude oil and refined products inventory	(16,241)	(17,246)
Other current assets and liabilities	1,562	(1,754)
Accounts payable and other accrued liabilities	(7,754)	7,375
Accrued crude oil purchases	16,489	38,176
Line 63 oil release reserve	(1,661)	13,496
Other non-current assets and liabilities	(2,897)	(301)
NET CASH PROVIDED BY OPERATING ACTIVITIES	6,015	15,858
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(2,361)	
Additions to property and equipment	(24,158)	(4,389)
Other	110	129
NET CASH USED IN INVESTING ACTIVITIES	(26,409)	(4,260)
CASH FLOWS FROM FINANCING ACTIVITIES		
Capital contributions from the general partner		2,438
Proceeds from credit facilities	74,417	26,833
Repayment of credit facilities	(37,366)	(25,854)
Deferred financing costs		(600)
Distributions to partners	(22,516)	(15,114)
Related parties	(229)	(661)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	14,306	(12,958)
Effect of exchange rates on cash	(32)	74
NET DECREASE IN CASH AND CASH EQUIVALENTS	(6,120)	(1,286)
CASH AND CASH EQUIVALENTS, beginning of reporting period	18,064	23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 11,944	$ 22,097

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2006
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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

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

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 months ended March 31, 2006 are not necessarily indicative of the results of operations for the full year. All significant intercompany balances and transactions have been eliminated during the consolidation process.

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

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

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised December 2004), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005. The adoption of SFAS 123R on January 1, 2006 did not have a material impact on the Partnership s consolidated financial statements. See Notes 3 and 5 to the condensed consolidated financial statements for more details on share-based compensation.

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

2. NET INCOME PER LIMITED PARTNER UNIT

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

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

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 has individually assumed and for which the limited partners are not responsible.

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

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Numerator:		
Net income allocated to limited partners:		
Net income	$ 11,614	$ 3,421
Costs allocated to the general partner(1):		
LB Pacific, LP Option Plan cost	511	
Senior Notes consent solicitation and other costs		893
Severance and other costs		914
Total costs allocated to the general partner	511	1,807
Income before costs allocated to the general partner	12,125	5,228
Less: general partner incentive distributions	(255)	
	11,870	5,228
General partner 2% ownership	(237)	(105)
Net income for the limited partners	$ 11,633	$ 5,123
Denominator:		
Basic weighted average limited partner units	39,301	29,655
Effect of restricted units	12	47
Effect of options		18
Diluted weighted average limited partner units	39,313	29,720
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.17

(1) See Note 3 Related Party Transactions for a description of costs reimbursed by the General Partner.

3. RELATED PARTY TRANSACTIONS

The Partnership s General Partner does not receive any management fee or other compensation in connection with its management of the Partnership s business, but is entitled to reimbursement for all direct and indirect expenses incurred on the Partnership s behalf.

Cost Reimbursements

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

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

The option plan is administered by the board of directors of LB Pacific GP, LLC. The terms, conditions, performance goals, restrictions, limitations, forfeiture, vesting or exercise schedule, and other provisions of grants under the plan, as well as eligibility to participate are determined by the board of directors of LB Pacific GP, LLC, the general partner of LBP. The board of directors of LB Pacific GP, LLC may determine to grant options under the plan to participants containing such terms as the board of LB Pacific GP, LLC shall determine. Options will have an exercise price that may not be less than the fair market value of the units on the date of grant. In general, options granted will become exercisable over a period determined by the board of directors of LB Pacific GP, LLC. In addition, the board of directors of LB Pacific GP, LLC may determine whether any unit options may become exercisable upon a change in control of LB Pacific GP, LLC, LB Pacific, LP, or our General Partner.

The board of directors of LB Pacific GP, LLC may terminate or amend the unit option plan at any time with respect to units for which a grant has not yet been made. However, no change may be made that would materially impair the rights of a participant with respect to an outstanding grant without the consent of the participant.

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

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

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

For the three months ended March 31, 2006, the Partnership recognized $0.5 million in compensation expense relating to the LBP options and recorded a capital contribution from the General Partner for the same amount. At March 31, 2006, there was $8.1 million of total unrecognized compensation cost related to nonvested options granted under the plan; that cost is expected to be recognized over the remaining period of 9.75 years. At March 31, 2006, all granted LBP options remained outstanding.

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

Other Related Party Transactions

Revenue from Related Parties: One of the Partnership s subsidiaries, Rocky Mountain Pipeline System LLC (RMPS) serves as the contract operator for certain gas producing properties owned by a subsidiary of Anschutz in Wyoming and Utah, in exchange for which RMPS is reimbursed its direct costs of operation and is paid an annual fee of $0.3 million as compensation for the time spent by RMPS management and for other overhead services related to their activities.

RMPS receives an operating fee and management fee from Frontier Pipeline Company (Frontier) in connection with time spent by RMPS management and for other services related to Frontier s activities. RMPS received $0.2 million for each of the three month periods ended March 31, 2006 and 2005. The Partnership owns a 22.22% partnership interest in Frontier.

Expenses Paid to Related Parties: Until December 31, 2005, the Partnership utilized the financial accounting system owned and provided by Anschutz under a shared services arrangement for a fee of $0.1 million per year and Anschutz charged the Partnership for any out-of-pocket costs it incurred. The fixed annual fee included all license, maintenance and employee costs associated with the Partnership s use of the financial accounting system.

In January 2003, the Partnership began leasing approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an annual cost of $0.1 million per year. The lease was terminated in February 2006.

4. CONTINGENCIES

Line 63 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 caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through anticipated completion in June 2007, the Partnership expects to incur an estimated total of $25.7 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 March 31, 2006, the Partnership had incurred approximately $21.4 million of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that $2.8 million of the remaining remediation costs will be incurred for the remainder of 2006 and $0.7 million (included in Other liabilities in the accompanying balance sheet) will be incurred in 2007.

The Partnership has a pollution liability insurance policy with a $2.0 million per-occurrence deductible that covers containment and clean-up costs, third-party claims and penalties. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. The Partnership believes that, subject to the $2.0 million deductible, it will be entitled to recover substantially all of its clean-up costs and any third-party claims associated with the release. As of March 31, 2006, the Partnership has recovered $15.6 million from insurance and recorded receivables of $8.1 million for future insurance recoveries it deems probable, of which $0.7 million is considered long-term and is included in Other assets, net in the accompanying consolidated balance sheet.

On or about March 17, 2006, Pacific Pipeline System LLC (PPS), a subsidiary of the Partnership, was served with a four count misdemeanor action by the state of California, which alleges that PPS violated various state statutes by depositing oil or substances harmful to wildlife into the environment and by the willful and intentional discharge of pollution into state waters. The Partnership estimates that the maximum fine and penalties that could be assessed for these actions is approximately $0.9 million in the aggregate. The Partnership believes, however, that certain of the alleged violations are without merit and intends to defend against them, and that mitigating factors should otherwise reduce the amounts of any potential fines or penalties that might be assessed. At this time, the Partnership cannot reasonably determine the outcome of these allegations. The estimated range of possible fines or penalties including amounts not covered by insurance is from $0 to $0.9 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 plans, the ongoing assessment of the impact of soil and water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that costs incurred in excess of this provision, if any, would not have a material adverse effect on the Partnership s financial condition, results of operations, or cash flows, though the Partnership believes that most, if not all, of any such excess cost, to the extent attributable to clean-up and third-party claims, would be recoverable through insurance. In March 2006, A.M. Best Company, an insurance company rating agency, announced it had downgraded the financial strength rating assigned to the Partnership s insurance carrier, Quanta Specialty Lines Company, including its parent and affiliates. The downgrade was from an A to a B++, under review with negative implications. Based on management s analysis of Quanta s financial condition, the Partnership believes that Quanta will continue to meet its obligations relating to the Line 63 oil release, although there can be no assurance that this will be the case. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

Litigation

In August, 2005, Rangeland Pipeline Company (RPC), a wholly-owned subsidiary of the Partnership, learned that a Statement of Claim was filed by Desiree Meier and Robert Meier in the Alberta Court of Queen s Bench, Judicial District of Red Deer, naming RPC as defendant, and alleging personal injury and property damage caused by an alleged release of petroleum substances onto plaintiff s land by a prior owner and operator of the pipeline that is currently owned and operated by the Partnership. The claim seeks Cdn$1 million (approximately U.S.$0.9 million at March 31, 2006) in general damages, Cdn$2 million (approximately U.S.$1.7 million at March 31, 2006) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. The Statement of Claim has not been served on RPC, so RPC has not been required to file an answer. RPC believes the claim is without merit, and intends to vigorously defend against it. RPC also believes that certain of the claims, if successfully proven by the plaintiffs, would be liabilities retained by the pipeline s prior owner under the terms of the agreement whereby the Partnership acquired the pipeline in question.

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

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

5. RESTRICTED UNITS

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

In January 2006, the General Partner awarded 46,815 restricted units to key employees that vest over a three-year period, beginning on March 1, 2006, and that are also subject to meeting annual financial performance objectives and to outside directors that vest over a three-year period beginning March 1, 2006. The financial measure used is the Partnership s distributable cash flow per unit, as determined by the Compensation Committee, for the calendar year preceding each of the three annual vesting dates. The number of units to be delivered in any year, if any, will be based on accomplishment of performance targets for the previous calendar year, subject to the Compensation Committee s authority to subsequently adjust performance targets as it may deem appropriate, in its discretion. Restricted unit activity during the three months ended March 31, 2006 is as follow:

	Number of Units	Weighted Average Grant Date Fair Value (in thousands)
Outstanding at January 1, 2006		$
Changes during the year:		
Granted	46,815	1,410
Vested	(10,439)	(314)
Forfeited	(5,166)	(156)
Outstanding at March 31, 2006	31,210	$ 940

Compensation expense recognized for granted performance restricted units is based on grant date fair value of the common units to be awarded to the grantee upon vesting of the phantom unit, adjusted for the expected target performance level for each year. For the three months ended March 31, 2006, the Partnership incurred $0.4 million in compensation expense for restricted units it deemed probable of achieving the performance criteria, including the amount for the first vesting of these awards which occurred on March 1, 2006.

6. SEGMENT INFORMATION

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

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

	West Coast Business Unit (in thousands)	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
Three months ended March 31, 2006				
Revenues:				
Pipeline transportation revenue	$ 17,163	$ 18,868	$ (2,174)	$ 33,857
Storage and terminaling revenue	20,086			20,086
Pipeline buy/sell transportation revenue(1)		9,699		9,699
Crude oil sales, net of purchases(2)	7,311	(360)	(142)	6,809
Net revenue	44,560	28,207		70,451
Expenses:				
Operating	21,432	14,303	(2,316)	33,419
Depreciation and amortization	5,499	4,503		10,002
Total expenses	26,931	18,806		43,421
Share of net income of Frontier		398		398
Operating income from segments(3)	$ 17,629	$ 9,799		$ 27,428
Business unit assets(4)	$ 884,143	$ 571,391		$ 1,455,534
Capital expenditures(5)	$ 11,610	$ 5,816		$ 17,426
Three months ended March 31, 2005				
Revenues:				
Pipeline transportation revenue	$ 17,443	$ 12,456	$ (1,862)	$ 28,037
Storage and terminaling revenue	10,472		(150)	10,322
Pipeline buy/sell transportation revenue(1)		9,106		9,106
Crude oil sales, net of purchases(2)	1,812		(30)	1,782
Net revenue	29,727	21,562		49,247
Expenses:				
Operating	14,507	9,289	(2,042)	21,754
Line 63 oil release costs(6)	2,000			2,000
Depreciation and amortization	3,477	3,052		6,529
Total expenses	19,984	12,341		30,283
Share of net income of Frontier		357		357
Operating income from segments(3)	$ 9,743	$ 9,578		$ 19,321
Business unit assets(4)	$ 538,568	$ 350,600		$ 889,168
Capital expenditures(5)	$ 750	$ 2,932		$ 3,682

(1) Pipeline buy/sell transportation revenue reflects net revenues of approximately $2.5 million on buy/sell transactions with different parties of $48.3 million. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of $256.3 million and $114.3 million for 2006 and 2005, respectively.

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

	Three Months Ended March 31,	
	2006	2005
	(in thousands)	
Income Statement Reconciliation		
Operating income from above:		
West Coast Business Unit	$ 17,629	$ 9,743
Rocky Mountain Business Unit	9,799	9,578
Operating income before general and administrative expense	27,428	19,321
Less: General and administrative expense	(6,873)	(5,172)
Less: Accelerated long-term incentive plan compensation expense		(3,115)
Less: Transaction costs		(1,807)
Operating income	20,555	9,227
Interest expense	(9,088)	(5,598)
Other income	443	353
Income tax expense	(296)	(561)
Net income	$ 11,614	$ 3,421

(4) Business unit assets do not include assets related to the Partnership s parent level activity. As of March 31, 2006 and 2005, parent level related assets were $50.7 million and $30.9 million respectively.

(5) Segment capital expenditures do not include parent level capital expenditures. Parent level capital expenditures were $6.7 million and $0.7 million for the three months ended March 31, 2006 and 2005, respectively.

(6) On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS s Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, the Partnership recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of what it now estimates to be $25.7 million of accrued costs relating to the release, net of insurance recoveries of $15.6 million to March 31, 2006 and accrued insurance receipts of $8.1 million.

7. SUBSEQUENT EVENT

On April 21, 2006, the Partnership declared a cash distribution of $0.5675 per limited partner unit, payable on May 12, 2006, to unitholders of record as of May 1, 2006.

8. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Certain of the Partnership s 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of the 7⅛% senior notes due 2014 and the 6¼% senior notes due 2015 (the Senior Notes). Given that certain, but not all subsidiaries of the Partnership are guarantors of its Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, the Partnership is referred to as Parent , while the Guarantor Subsidiaries are Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Ranch Pipeline LLC, PEG Canada GP LLC, PEG Canada, L.P. and Pacific Energy Group LLC, and Non-Guarantor Subsidiaries are Pacific Pipeline System LLC, Pacific Terminals LLC, Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership and Aurora Pipeline Company, Ltd.

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

	Balance Sheet March 31, 2006				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Assets:					
Current assets	$ 104,875	$ 157,298	$ 66,849	$ (122,836)	$ 206,186
Property and equipment		597,088	608,554		1,205,642
Equity investments	449,804	212,513		(654,228)	8,089
Intercompany notes receivable	662,763	340,838		(1,003,601)	
Intangible assets		30,819	37,607		68,426
Other assets	11,304	(244)	6,847		17,907
Total assets	$ 1,228,746	$ 1,338,312	$ 719,857	$ (1,780,665)	$ 1,506,250
Liabilities and partners capital:					
Current liabilities	$ 5,273	$ 215,309	$ 63,251	$ (122,836)	$ 160,997
Long-term debt	535,269		65,716		600,985
Deferred income taxes		597	35,034		35,631
Intercompany notes payable		662,763	340,838	(1,003,601)	
Other liabilities		9,839	10,594		20,433
Total partners capital	688,204	449,804	204,424	(654,228)	688,204
Total liabilities and partners capital	$ 1,228,746	$ 1,338,312	$ 719,857	$ (1,780,665)	$ 1,506,250

	Balance Sheet December 31, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Assets:					
Current assets	$ 104,989	$ 139,457	$ 81,846	$ (134,177)	$ 192,115
Property and equipment		583,330	602,204		1,185,534
Equity investments	429,802	197,239		(618,885)	8,156
Intercompany notes receivable	661,313	340,905		(1,002,218)	
Intangible assets		31,220	37,960		69,180
Other assets	13,426		8,041		21,467
Total assets	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452
Liabilities and partners capital:					
Current liabilities	$ 5,389	$ 191,516	$ 93,459	$ (134,177)	$ 156,187
Long-term debt	505,902		59,730		565,632
Deferred income taxes		582	35,189		35,771
Intercompany notes payable		661,313	340,905	(1,002,218)	
Other liabilities		8,938	11,685		20,623
Total partners capital	698,239	429,802	189,083	(618,885)	698,239
Total liabilities and partners capital	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452

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	Statement of Income Three Months Ended March 31, 2006				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Net operating revenues	$	$ 35,219	$ 37,547	$ (2,315)	$ 70,451
Operating expenses		(19,088)	(16,646)	2,315	(33,419)
General and administrative expense(1)		(6,210)	(663)		(6,873)
Accelerated long-term incentive plan compensation expense					
Line 63 oil release costs					
Transaction costs					
Depreciation and amortization expense		(4,928)	(5,074)		(10,002)
Share of net income of Frontier		398			398
Operating income		5,391	15,164		20,555
Interest expense	(8,108)	(81)	(899)		(9,088)
Intercompany interest income (expense)		7,169	(7,169)		
Equity earnings	19,942	7,404		(27,346)	
Other income	(220)	337	326		443
Income tax benefit (expense)		(278)	(18)		(296)
Net income	$ 11,614	$ 19,942	$ 7,404	$ (27,346)	$ 11,614

	Statement of Income Three Months Ended March 31, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Net operating revenues	$	$ 14,268	$ 37,021	$ (2,042)	$ 49,247
Operating expenses		(9,968)	(13,828)	2,042	(21,754)
General and administrative expense(1)		(4,618)	(554)		(5,172)
Accelerated long-term incentive plan compensation expense		(2,684)	(431)		(3,115)
Line 63 oil release costs			(2,000)		(2,000)
Transaction costs	(893)	(914)			(1,807)
Depreciation and amortization expense		(1,624)	(4,905)		(6,529)
Share of net income of Frontier		357			357
Operating income	(893)	(5,183)	15,303		9,227
Interest expense	(4,078)	(679)	(841)		(5,598)
Intercompany interest income (expense)		6,271	(6,271)		
Equity earnings	8,384	7,990		(16,374)	
Other income	8	166	179		353
Income tax benefit (expense)		(181)	(380)		(561)
Net income	$ 3,421	$ 8,384	$ 7,990	$ (16,374)	$ 3,421

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

	Statement of Cash Flows Three Months Ended March 31, 2006				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 11,614	$ 19,942	$ 7,404	$ (27,346)	$ 11,614
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(19,942)	(7,404)		27,346	
Distributions from subsidiaries	22,516	11,732		(34,248)	
Depreciation, amortization and other	1,024	5,330	5,047		11,401
Net changes in operating assets and liabilities	(188)	(7,838)	(7,126)	(1,848)	(17,000)
NET CASH PROVIDED BY OPERATING ACTIVITIES	15,024	21,762	5,325	(36,096)	6,015
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions		(2,361)			(2,361)
Additions to property, equipment and other	(72)	(15,889)	(8,087)		(24,048)
Intercompany	(31,000)			31,000	
NET CASH USED IN INVESTING ACTIVITIES	(31,072)	(18,250)	(8,087)	31,000	(26,409)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	17,006	(13,620)	5,824	5,096	14,306
Effect of translation adjustment			(32)		(32)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	958	(10,108)	3,030		(6,120)
CASH AND CASH EQUIVALENTS, beginning of reporting period	4,192	12,484	1,388		18,064
CASH AND CASH EQUIVALENTS, end of reporting period	$ 5,150	$ 2,376	$ 4,418	$	$ 11,944

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	Statement of Cash Flows Three Months Ended March 31, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 3,421	$ 8,384	$ 7,990	$ (16,374)	$ 3,421
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(8,384)	(7,990)		16,374	
Distributions from subsidiaries	15,114	12,673		(27,787)	
Depreciation, amortization and other	157	4,325	4,864		9,346
Net changes in operating assets and liabilities	3,915	1,840	74	(2,738)	3,091
NET CASH PROVIDED BY OPERATING ACTIVITIES	14,223	19,232	12,928	(30,525)	15,858
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property, equipment and other		(1,091)	(3,169)		(4,260)
Intercompany	(914)			914	
NET CASH USED IN INVESTING ACTIVITIES	(914)	(1,091)	(3,169)	914	(4,260)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(14,894)	(18,276)	(7,984)	28,196	(12,958)
Effect of translation adjustment			74		74
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,585)	(1,476)	1,775		(1,286)
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713	17,523	3,147		23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 1,128	$ 16,047	$ 4,922	$	$ 22,097

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

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

Forward-Looking Statements

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

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil, refined products and other related products and buying 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, 2005, 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, 2005.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing, and distributing crude oil, refined products and other related products. We generate revenue primarily by transporting such commodities on our pipelines, by leasing capacity in our storage tanks, and by providing other terminaling services. We also buy and sell crude oil, activities that are generally complementary to our other crude oil operations. We conduct our business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

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

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

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

Recent Business Developments

The Rocky Mountain business unit accomplished several positive initiatives in the first quarter of 2006. The construction of the initiating facility for synthetic crude oil in Edmonton, Alberta was completed in March 2006, and initial movements of synthetic crude oil began immediately thereafter. This connection provides direct access to synthetic crude oil in Edmonton for delivery through our pipeline systems to U.S. Rocky Mountain refineries. In addition, to facilitate the movement and maintain the quality of of synthetic crude oil, three 120,000 barrel tanks were constructed at storage facilities along the pipeline system.

The Rocky Mountain Business Unit proceeded with its plans to construct a Salt Lake City core expansion project that will expand its crude oil pipeline system from the terminus of Frontier Pipeline near Evanston, Wyoming to the Salt Lake City, Utah refining complex. The new 16-inch pipeline, which will be 91 miles in length, will be able to transport multiple grades of crude oil in segregated batches and will provide 95,000 barrels per day of capacity to meet increased crude oil demand in Salt Lake City. The project will be constructed in two phases, the first phase estimated to be completed in the fourth quarter of 2006, the second phase by October 2007. The total cost for both phases of the project is expected to be approximately $77 million and is supported by firm, 10-year transportation agreements that have been executed with four Salt Lake City refiners.

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

In our West Coast business unit, we are currently constructing 450,000 barrels of storage capacity at our Martinez terminal in the San Francisco area, which is expected to be completed in the third quarter of 2006. At our Philadelphia area terminals, we are completing an ethanol expansion project which will enable us to increase our ethanol storage, handling and blending capabilities. At Pacific Terminals, we are refurbishing 600,000 barrels of black oil storage as well as making infrastructure changes to increase pumping capacity and improve operating efficiencies. These projects are expected to be completed in the second half of 2006.

Business Fundamentals

Pipeline Transportation

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

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

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

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

Following are recent tariff rate increases on our pipelines:

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

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

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

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

These tariff rate increases on our West Coast pipelines partially mitigate the impact of declining throughput.

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

In the Rocky Mountains, our pipelines are connected to U.S. and Canadian sources of crude oil. Our Rangeland system in Alberta gives us 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. Our initiating pump station in Edmonton, as well as a connection to a third-party pipeline providing access to synthetic crude oil, was completed in March 2006. 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 in the U.S. Rocky Mountains will resume its historical decline.

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

Storage and Terminaling

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

Demand for crude oil storage capacity tends to be more stable over time and leases for crude oil storage capacity are usually long term (more than one year). Demand for storage capacity for other dark products is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for other dark products storage capacity are usually short term (less that one year). One of our business goals is to convert a number of dark products tanks to more flexible crude oil service (which can also continue to accommodate other dark products); and we have recently completed one such tank conversion. While PT s rates are subject to regulation by the CPUC, the CPUC has allowed PT to establish rates based on market conditions through negotiated contracts.

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

Demand for refined products storage at our San Francisco area terminals tends to be stable over time as most of their lease contracts are evergreen contracts for a year or more. Additionally, the San Francisco area terminals are not overly reliant on local area refinery production to satisfy their supply of refined products. The San Francisco area terminals receive a significant amount of their supplies from imported refined products and crude oil into the San Francisco harbor. One of our goals is to increase the storage capacity of our Martinez terminal. We have begun construction of 450,000 barrels of storage, which we expect to place in service in the third quarter of 2006.

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

Pipeline Buy/Sell Transportation

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

We 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 of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta, which began operating in March 2006. The volume of throughput originating at our Edmonton, Alberta initiation station will vary with our success in attracting new supplies of synthetic crude oil to our system.

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

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

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

Gathering Activities and Marketing Business

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

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

The contribution of our PMT gathering 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 gathering operations, and the price of the crude oil it sells. Costs and sales prices are generally impacted by crude oil prices, as well as by local supply and demand forces, including regulations affecting refined product specifications. Second, it varies with the price differential between crude oil purchased on one price basis and sold on another price basis. Third, it varies with the volumes gathered. Finally, it varies with the effectiveness of our hedging program. We seek to control these variations through our risk management policy, which provides specific guidelines for our crude oil marketing and hedging activities and requires oversight by our senior management.

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. In 2006, we have a $150 million expansion capital spending forecast as detailed in Liquidity and Capital Resources Capital Requirements below. We also intend to expand, principally by acquisition, into the natural gas storage and transportation businesses. We expect the acquisitions and new projects will be accretive to our cash flow and complement our existing business. We expect to fund acquisitions and new projects with a combination of debt and additional Partnership units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

Operating Expenses

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

We do not have any employees, except in Canada. Our General Partner provides employees to conduct our U.S. operations. We and our General Partner collectively employ approximately 440 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey, terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us.

Impact of Foreign Exchange Rates

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

Critical Accounting Policies and Estimates

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

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

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

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

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

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

Results of Operations

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

Line 63 Oil Release. On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS s Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, we recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of what we now estimate to be $25.7 million of total costs relating to the release, net of insurance recoveries of $15.6 million to date and accrued future insurance recoveries of $8.1 million at March 31, 2006.

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

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

Three Months Ended March 31, 2006 Compared to Three Months Ended March 31, 2005

Summary

Net income for the three months ended March 31, 2006 was $11.6 million, or $0.30 per diluted limited partner unit, compared to $3.4 million, or $0.17 per diluted limited partner unit, for the three months ended March 31, 2005.

Net income for the three months ended March 31, 2006 reflects the benefit of the operations of the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals, which were acquired on September 30, 2005.

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

		Three Months Ended March 31, 2006 (In thousands)	2005	Change	Percent
Net income		$ 11,614	$ 3,421	$ 8,193	239 %
Add:	Line 63 oil release costs		2,000	2,000	
	Accelerated long-term incentive plan compensation expense		3,115	3,115	
	Transaction costs		1,807	1,807	
		$ 11,614	$ 10,343	$ 1,271	12 %
Diluted weighted average limited partner units		39,313	29,720	9,593	32 %

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 San Francisco and Philadelphia area terminals and the Rocky Mountain Products Pipeline acquired in September 2005; and (ii) increased margins in our gathering and marketing business. These increases were partially offset by significant impacts to the Rocky Mountain Business Unit caused by substantial downtime at a Rocky Mountain refinery, lower tank utilization at Pacific Terminals, increased general and administrative costs, and higher interest expense primarily due to higher debt levels. There were 39.3 million weighted average limited partner units outstanding in the three months ended March 31, 2006, approximately 32% more limited partner units than the 29.7 million weighted average units outstanding in the three months ended March 31, 2005, due to the sale of additional common units to partially fund the acquisition of the San Francisco and Philadelphia area terminals and the Rocky Mountain Products Pipeline.

Segment Information

The following is a discussion of segment operating income, which does not include general and administrative expenses, 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. The following also excludes a discussion of the Line 63 oil release discussed above.

West Coast	Three Months Ended March 31, 2006 (In thousands)	2005	Change	Percent
Operating income	$ 17,629	$ 9,743	$ 7,886	81 %
Add: Line 63 oil release cost		2,000	2,000	
	$ 17,629	$ 11,743	$ 5,886	50 %
Operating data:				
Pipeline throughput (bpd)	118.6	138.5	(19.9)	(14)%

West Coast operating income was higher in 2006 due to the result of operations of the San Francisco and Philadelphia area terminals, which were acquired in September 2005, and higher margins in our gathering and marketing business, which were below average in 2005. Margins were below average in 2005 in our gathering and marketing business due to pricing pressures from steeply discounted crude oil imports, the interruption of a scheduled sale due to the Line 63 crude oil release, and an unfavorable purchase contract which expired on March 31, 2005. In addition, crude oil contracts acquired on July 1, 2005 benefited our gathering and marketing business in the first quarter of 2006. Partially offsetting these increases were lower tank utilization in our PT storage and distribution operations, which was 8% lower than in the first quarter of 2005 when a record utilization of 94% was achieved. The prior year utilization was the result of extensive refinery maintenance and resultant demand for black oil storage in the first quarter of 2005. Although West Coast pipeline volumes were approximately 14% lower than in 2005, this decline was largely offset by tariff increases on Line 2000 and Line 63 and increased deliveries to Bakersfield. Reduced volumes on our West Coast pipelines were caused by lower San Joaquin Valley and Outer Continental Shelf production, third-party production problems and higher than normal San Francisco area refinery turnarounds in the first quarter of 2005. We benefited from those turnarounds in 2005 because they increased volumes transported by us south to Los Angeles area refineries.

Rocky Mountains	**Three Months Ended March 31, 2006**	**2005**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 9,799	$ 9,578	$ 221	2 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	24.7	21.4	3.3	15
Sundre South	40.7	48.2	(7.5)	(16)
Western Corridor system	24.4	22.5	1.9	8
Salt Lake City Core system	123.8	108.7	15.1	14
Frontier pipeline	48.2	38.3	9.9	26
Rocky Mountain Products Pipeline	61.5		61.5	

For the three months ended March 31, 2006, operating income was $9.8 million compared to $9.6 million for the three months ended March 31, 2005. Extensive downtime in the first quarter of 2006 at a major Rocky Mountain refinery had a significant impact on income in the Rocky Mountain business unit. Lower volumes moved south on the Rangeland system and lower volumes were experienced on the Rocky Mountains Product Pipeline. In addition, the refinery s downtime negatively impacted pricing of our crude oil inventory at the end of the quarter. Offsetting these decreases were the results of operations of the Rocky Mountain Products Pipeline acquired in September 2005 and increased volumes on the Western Corridor and Salt Lake City Core crude oil pipelines.

Statement of Income Discussion and Analysis

Revenues	Three Months Ended March 31, 2006 (In thousands)	2005	Change	Percent
Pipeline transportation revenue	$ 33,857	$ 28,037	$ 5,820	21 %
Storage and terminaling revenue	20,086	10,322	9,764	95
Pipeline buy/sell transportation revenue	9,699	9,106	593	7
Crude oil sales, net of purchases:				
Crude oil sales	263,128	116,173	146,955	126
Crude oil purchases	(256,319)	(114,391)	141,928	124
Crude oil sales, net of purchases	6,809	1,782	5,027	282
Net revenue	$ 70,451	$ 49,247	$ 21,204	43 %

Increased pipeline transportation revenues were realized by our U.S. Rocky Mountain crude oil pipelines because of higher volumes, and increased trucking revenue resulted from the purchase of a crude oil trucking business for $2.4 million in January 2006. Additionally, pipeline transportation revenues in 2006 include revenues for our Rocky Mountain Products Pipeline, which was acquired in September 2005. The impact of lower pipeline transportation volumes in our West Coast business unit was largely offset by higher tariffs.

Storage and terminaling revenues increased in 2006 primarily because of the acquisition of the San Francisco and Philadelphia area terminals in September 2005. This increase was partially offset by a decline in tank utilization on our Pacific Terminals storage and distribution system.

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

Expenses	Three Months Ended March 31, 2006 (In thousands)	2005	Change	Percent
Operating expenses	$ 33,419	$ 21,754	$ 11,665	54 %
General and administrative expense	6,873	5,172	1,701	33
Accelerated long-term incentive plan compensation expense		3,115	3,115	
Line 63 oil release costs		2,000	2,000	
Transaction costs		1,807	1,807	
Depreciation and amortization	10,002	6,529	3,473	53
	$ 50,294	$ 40,377	$ 9,917	25 %

Accelerated long-term incentive plan compensation expense, Line 63 oil release costs and transaction costs are discussed above.

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

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

Schedule K-1 costs, were higher in the first quarter of 2006 than they are expected to be in the remaining quarters of 2006.

The increase in depreciation and amortization includes $3.2 million for depreciation on the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals.

Other Income and Expense	Three Months Ended March 31, 2006	2005	Change	Percent
	(In thousands)			
Share of net income of Frontier	$ 398	$ 357	$ 41	11 %
Interest expense	9,088	5,598	3,490	62
Other income	443	353	90	25
Income tax expense	296	561	(265)	(47)

The increase in our share of Frontier s net income was mainly attributable to increased pipeline volumes in 2006. In 2005, pipeline volumes were lower as a result of a shortage of synthetic crude supply caused by a fire at a Suncor Energy, Inc. facility in December 2004.

The increase in interest expense was primarily due to borrowings incurred to partially fund the acquisition of the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals. Our weighted average borrowings during the three months ended March 31, 2006 were $579 million, compared to $358 million in the corresponding period in 2005. Floating interest rates were higher in 2006, at a weighted average interest rate of 6.9% for the period ended March 31, 2006, compared to a weighted average interest rate of 6.3% for the corresponding period in 2005. Offsetting the effect of the increase in interest rates was increased capitalized interest, $0.8 million and $0.1 million for the three months ended March 31, 2006 and 2005, respectively

Other income of $0.4 million for the period ended March 31, 2006 was consistent with the corresponding period in 2005.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities in Canada. In addition, certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. Our Canadian subsidiaries income was lower in 2006 compared to 2005 due to lower crude oil volumes moving south to the U.S. Rocky Mountains.

Liquidity and Capital Resources

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

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

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

We received permission from the CPUC to dismantle certain idle PT assets and sell the underlying land, which has an estimated value of approximately $10 million. We expect to sell these various parcels of land in 2006.

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

Operating, Investing and Financing Activities

	Three Months Ended March 31, 2006	2005	Change
	(In thousands)		
Net cash provided by operating activities	$ 6,015	$ 15,858	$ (9,843)
Net cash used in investing activities	(26,409)	(4,260)	(22,149)
Net cash provided by (used in) financing activities	14,306	(12,958)	27,264

Net cash provided by operating activities

Net cash from operating activities in 2006 was positively impacted by an increase in net income due to the operations of the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals, which were acquired on September 30, 2005, and increased margins in our gathering and marketing business. Offsetting these increases were (i) significant impacts to the Rocky Mountain Business Unit caused by substantial downtime at a Rocky Mountain refinery, (ii) lower tank utilization at Pacific Terminals, (iii) increased general and administrative costs and higher interest expense due to higher debt levels and interest rates. Cash flow provided by operating activities was reduced by a decrease in accounts payable and other accrued liabilities and an increase in the storage of crude oil because of contango market conditions (when oil prices for future deliveries are higher than for current deliveries). In a contango market we store crude oil purchased at lower prices in the current month for delivery at higher prices in future months, and protect such margin through hedging. As such, cash provided by operating activities was adversely affected by the change in the crude oil purchases liability net of crude oil receivables reflecting the timing of the inventory build-up.

Net cash used in investing activities

Capital expenditures of $24.2 million for the three months ended March 31, 2006 include $13.6 million for expansion projects (see Capital Requirements below for a list of our forecasted expansion projects in 2006), $6.6 million for the development of the Pier 400 project, $0.8 million related to sustaining capital projects and $3.2 million of transition projects related to the Edmonton initiation station as well as the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals. Capital expenditures for the three months ended March 31, 2005 were $4.4 million, of which $0.2 million related to sustaining capital projects, $2.3 million related to transition projects, $1.2 million related to expansion and $0.7 million was for the development of the Pier 400 Project.

Net cash provided by and used in financing activities

Net cash provided by financing activities for the three months ended March 31, 2006 includes net borrowings of $37.1 million under our senior secured credit facility, which was used primarily to fund our expansion capital projects (see Capital Requirements below for a list of our forecasted expansion projects in 2006). We also distributed $22.5 million to our limited partners and General Partner during the three months ended March 31, 2006. Cash distributions of $15.1 million were paid during the period ended March 31, 2005.

Capital Requirements

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

We expect to invest approximately $166 million in total capital expenditures in 2006, with approximately $150 million of that total on expansion projects. Our estimated 2006 expansion capital spending includes the following notable projects.

2006 Forecast Expansion Capital Expenditures	**Estimated to be incurred in 2006 (in millions)**
Phase I of Salt Lake City expansion, and beginning of phase II	$ 44
2006 portion of the construction of a new pipeline to Cheyenne, Wyoming	31
Capital projects associated with the new refined products assets	23
Completion of permitting process, engineering and other project development cost for the Pier 400 project	21
Reactivation of storage tanks and infrastructure enhancements at PT	11
Completion of storage tanks for the Rangeland System and Western Corridor pipeline to facilitate the transportation of synthetic crude oil	4
Other	16
Total	$ 150

In addition to the expansion projects above, we expect to incur $7 million for transitional capital expenditures and $9 million for sustaining capital expenditures during 2006.

Pier 400

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

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

We recently completed an updated cost estimate for the project. We are estimating that Pier 400 will cost approximately $315 million, which is subject to change depending on various factors, including: (i) the final scope of the project and the requirements imposed through the permitting process; and (ii) changes in construction costs. This cost estimate now assumes the construction of 4.0 million barrels of storage, up from 3.0 million barrels previously estimated. As a result, the capital cost estimate has increased together with a commensurate increase in expected revenues. We are in the process of securing the environmental and other permits that will be required for the Pier 400 Project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in the first quarter of 2007.

Final construction of the Pier 400 Project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. We expect construction of the Pier 400 terminal to be completed and the facility to be placed in service in the first half of 2008.

We have capitalized $24.9 million on the Pier 400 project through March 31, 2006, including $6.6 million for the three months ended March 31, 2006. We anticipate funding the remaining permitting and pre-construction costs in 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

Our debt obligations consist of:

	March 31, 2006 (in thousands)	**December 31, 2005**
$400 million senior secured credit facility, bearing interest at 5.3% on March 31, 2006, due September 30, 2010	$ 177,691	$ 140,751
7 1⁄8% senior notes, due June 2014, net of unamortized discount of $3,800 and $3,882 and including fair value (decreases) increases of $(1,163) and $567, respectively	245,037	246,684
6 1⁄4% senior notes, due September 2015, net of unamortized discount of $768 and $782, respectively	174,232	174,218
Future payment for MAPL assets, net of unamortized discount of $259 and $309, respectively	4,025	3,979
Total long-term debt	$ 600,985	$ 565,632

As of March 31, 2006, $113 million of undrawn credit was available under the senior secured revolving credit facility. With the consent of the administrative agent under the revolving credit facility, we can increase credit availability up to an additional $84 million, based upon pro-forma EBITDA from future acquisitions.

Off-Balance Sheet Arrangements

As of March 31, 2006, we had standby letters of credit outstanding of $25.1 million for securing crude oil purchases and the MAPL note, both of which are reflected as liabilities on the balance sheet.

Accounting Pronouncements

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

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

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk Hedging

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

Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. For the three months ended March 31, 2006 and 2005, crude oil sales, net of purchases were net of $1.9 million and $1.0 million in losses, respectively, reflecting changes in the fair value of derivative instruments held as hedges related to crude oil marketing activities. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. Changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in accumulated other comprehensive income, a component of partners capital in the balance sheet, until the related revenue is reflected in the consolidated statements of income. As of March 31, 2006, no amount relating to the change in the fair value of highly effective derivative instruments was included in accumulated other comprehensive income .

Interest Rate Risk Hedging

In connection with the issuance of our 7⅛% senior notes due 2014, we entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7⅛% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the 7⅛% 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 March 31, 2006, we recorded a decrease of $1.2 million in the fair value of interest rate swaps. For the three months ended March 31, 2006, we recognized reductions in interest expense of $0.1 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. For the three months ended March 31, 2006, we had an immaterial amount of ineffectiveness relating to these interest rate swaps.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the $80 million interest swap on the senior notes are based on variable rates. If our interest rates were to increase 1.0% for the remainder of 2006 as compared to the rate at December 31, 2005, our interest expense for the remainder of 2006 would increase $1.9 million based on our outstanding debt balances at March 31, 2006.

Currency Exchange Rate Risk Hedging

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

We entered into forward exchange contracts to hedge receipt of forecasted interest payments denominated in Canadian dollars. The effective portion of the change in fair value of this contract, which has been designated as a cash flow hedge, is reported in accumulated other comprehensive income in the accompanying balance sheet and will be reclassified into earnings in Other income in the same period during which the hedged transaction affects earnings. The ineffective portion, if any, of the change in fair value of this instrument will be immediately recognized in earnings. These foreign exchange contracts as of March 31, 2006 are as follows:

	Canadian dollars (in thousands)	US dollars	Average Exchange Rate
2006	$ 5,500	$ 4,673	Cdn$1.18 to U.S. $1.00
2007	6,600	5,662	Cdn$1.17 to U.S. $1.00
2008	3,193	2,754	Cdn$1.16 to U.S. $1.00

Credit Risks

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

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

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

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

Based on their evaluation as of March 31, 2006, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Internal Control Over Financial Reporting

Our management, including the Chief Executive Officer and Chief Financial Officer, have evaluated our internal control over financial reporting as of March 31, 2006, and have concluded that there has not been any change during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

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

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

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

ITEM 1A. Risk Factors

There has been no material change in risk factors as previously disclosed in our annual report on Form 10-K for the year ended December 31, 2005.

ITEM 6. Exhibits

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

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

* Filed herewith.

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

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SIGNATURES

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

PACIFIC ENERGY PARTNERS, L.P.

By: **PACIFIC ENERGY GP, 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)
May 10, 2006

By: /S/ GERALD A. TYWONIUK
Gerald A. Tywoniuk
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)
May 10, 2006

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