PACIFIC ENERGY PARTNERS LP
Form 10-Q
May 13, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2003

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
(Address of principal executive offices)

(562) 728-2800
(Registrant's telephone number, including area code)

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

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

There were 10,465,000 of the registrant's Common Units and 10,465,000 of the registrant's Subordinated Units outstanding at April 29, 2003.

PACIFIC ENERGY PARTNERS, L.P.
Successor to Pacific Energy (Predecessor)

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2002	March 31, 2003
	(in thousands)	
		(unaudited)

	December 31, 2002	March 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,873	$ 19,376
Crude oil sales receivable	24,157	30,773
Transportation accounts receivable	10,568	13,157
Crude oil inventory	3,887	4,746
Spare parts inventory	445	446
Prepaid expenses	2,720	2,099
Other	421	14
Total current assets	66,071	70,611
Property and equipment, net	404,842	401,335
Investment in Frontier (note 3)	9,175	8,424
Other assets	6,950	6,701
	$ 487,038	$ 487,071
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 2,752	$ 1,086
Accrued crude oil purchases	24,385	29,587
Provision for right-of-way costs	350	350
Accrued power costs	1,706	1,714
Accrued interest payable	2,542	2,420
Due to related parties	952	671
Derivatives liability current portion (note 1)	4,775	5,232
Other	4,181	4,823
Total current liabilities	41,643	45,883
Long-term debt (note 5)	225,000	225,000
Derivatives liability (note 1)	2,600	3,004
Other liabilities	2,600	2,600
Total liabilities	271,843	276,487
Commitments and contingencies (notes 2 and 7)		
Partners' Capital:		
Common unitholders (10,465,000 units outstanding at March 31, 2003 and December 31, 2002)	163,172	161,335
Subordinated unitholders (10,465,000 units outstanding at March 31, 2003 and December 31, 2002)	57,069	55,231
General Partner interest	2,329	2,254
Accumulated other comprehensive loss (note 1)	(7,375)	(8,236)
Net partners' capital	215,195	210,584
	$ 487,038	$ 487,071

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	For the Three Months Ended	
	March 31, 2002	March 31, 2003
	(in thousands, except per unit data)	
	(unaudited)	
Pipeline transportation revenue	$ 21,069	$ 25,291
Crude oil sales, net of purchases of $59,929 and $86,622 for the three months ended March 31, 2002 and 2003, respectively	5,526	5,659
Net revenues before operating expenses	26,595	30,950
Expenses:		
Operating	11,206	12,648
Transition costs	832	397
General and administrative	1,342	3,982
Depreciation and amortization	3,087	4,181
	16,467	21,208
Share of net income of Frontier	268	341
Operating income	10,396	10,083
Other income	117	35
Interest income	185	56
Interest expense	(1,517)	(4,046)
Net income	$ 9,181	$ 6,128
Net income for the general partner interest for the three months ended March 31, 2003		$ 123
Net income for the limited partner interests for the three months ended March 31, 2003		$ 6,005
Basic and diluted net income per limited partner unit		$ 0.29
Weighted average limited partner units outstanding for the three months ended March 31, 2003:		
Basic		20,930
Diluted		21,000

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

	Limited Partner Units		Limited Partner Amounts				
	Common	Subordinated	Common	Subordinated	General Partner Interest	Accumulated Other Comprehensive Loss	Total
	(in thousands) (unaudited)						
Balance, December 31, 2002	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$ (7,375)	$ 215,195
Distribution to limited partners			(4,840)	(4,840)			(9,680)
Distribution to general partner					(198)		(198)
Net income			3,003	3,002	123		6,128
Change in fair value of interest rate hedging derivatives (note 1)						(861)	(861)
Balance, March 31, 2003	10,465	10,465	$ 161,335	$ 55,231	$ 2,254	$ (8,236)	$ 210,584

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Three Months Ended	
	March 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Net income	$ 9,181	$ 6,128
Change in fair value of interest rate hedging derivatives (note 1)		(861)
Comprehensive income	$ 9,181	$ 5,267

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Three Months Ended	
	March 31, 2002	**March 31, 2003**
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 9,181	$ 6,128
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	3,087	4,181
Amortization of debt issue costs		270
Share of net income of Frontier	(268)	(341)
	12,000	10,238
Net changes in operating assets and liabilities:		
Accounts receivable	(6,946)	(9,205)
Due to related party	1,521	(281)
Inventory	(1,535)	(860)
Prepaid expenses	355	621
Other current and non-current assets	(173)	319
Accounts payable	2,151	(1,666)
Accrued expenses	(229)	5,088
Provision for loss on rate case litigation	(1,500)	
Distributions (to) from Frontier, net	(684)	998
Other current and non-current liabilities	(1,446)	642
	(8,486)	(4,344)
NET CASH PROVIDED BY OPERATING ACTIVITIES	3,514	5,894
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of pipeline assets	(96,055)	
Additions to property and equipment	(564)	(560)
Disposal of equipment		47
NET CASH USED IN INVESTING ACTIVITIES	(96,619)	(513)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from note payable to bank	87,000	
Related party note payable	(122)	
Capital contributions of members (pre initial public offering)	8,744	
Distributions to members (pre initial public offering)	(6,000)	
Distributions to limited partners (post initial public offering)		(9,680)
Distributions to general partner (post initial public offering)		(198)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	89,622	(9,878)

	For the Three Months Ended	
NET DECREASE IN CASH AND CASH EQUIVALENTS	(3,483)	(4,497)
CASH AND CASH EQUIVALENTS, beginning of reporting period	9,511	23,873
CASH AND CASH EQUIVALENTS, end of reporting period	$ 6,028	$ 19,376
Supplemental disclosure		
Cash paid for interest	$ 1,209	$ 3,860
Noncash financing activities change in fair value of interest rate hedging derivatives	$	$ 861

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.
Successor to Pacific Energy (Predecessor)

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2003

(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

On July 26, 2002, Pacific Energy Partners, L.P. (the "Partnership") completed an initial public offering of 8,600,000 common units representing limited partner interests in the Partnership for net proceeds of $151.3 million. Accordingly, net income per limited partner unit for the three months ended March 31, 2002 in the accompanying condensed consolidated income statement is not applicable. The Partnership, which was formed by The Anschutz Corporation ("Anschutz") in February 2002, and its subsidiaries are engaged in gathering, blending, transporting, storing and distributing crude oil.

Anschutz, through Pacific Energy GP, Inc., an indirect, wholly-owned subsidiary of Anschutz and the general partner of the Partnership (the "General Partner"), conveyed to the Partnership its ownership interests in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owners of the PMT gathering and blending assets, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline and successor to Anschutz Ranch East Pipeline, Inc., and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier") and successor to Ranch Pipeline, Inc. Anschutz made this conveyance in exchange for: (i) the continuation of its 2% general partner interest in the Partnership, (ii) incentive distribution rights (as defined in its partnership agreement), (iii) 1,865,000 common units, (iv) 10,465,000 subordinated units, and (v) $105.1 million from borrowings under PEG's term loan on closing of the initial public offering.

PPS, PMT, AREPI, RMP and RPL, collectively, constitute the Partnership's predecessor, which is referred to herein as "Pacific Energy (Predecessor)" or the "Predecessor." The transfer of ownership interests in the entities that constitute Pacific Energy (Predecessor) to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. The condensed consolidated financial statements (combined prior to July 26, 2002) includes the financial position, results of operations, changes in partners' capital and cash flows of the Partnership, PEG, PPS, PMT, RMP, AREPI and RPL. All significant intercompany balances and transactions have been eliminated during the consolidation process.

The unaudited condensed consolidated financial statements present the Partnership as a single entity, separate from Anschutz, during the periods presented. The 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 by accounting principles 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, 2003 are not necessarily indicative of the results of operations for the full year. The financial data for the three months ended March 31, 2003 is derived from the Partnership's unaudited consolidated financial statements. The financial data as of December 31, 2002 is derived from the Partnership's audited consolidated financial statements. The

financial data for the three months ended March 31, 2002 is derived from the unaudited combined financial statements of Pacific Energy (Predecessor).

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, 2002.

Description of Business and History

PEG was formed in August 2001, and at March 31, 2003 and December 31, 2002, owned 100% of PPS, PMT, RMP, AREPI and RPL.

PPS owns and operates two crude oil pipelines, Line 2000 and the Line 63 system. In January 1999, PPS completed construction of Line 2000, a 130-mile crude oil pipeline that extends from Kern County in the San Joaquin Valley of California to the Los Angeles Basin, where it has direct and indirect connections to various refineries and terminal facilities. Line 2000 has a permitted annual average throughput capacity of 130,000 barrels of crude oil per day. Shipments of crude oil on Line 2000 began on February 23, 1999.

Effective May 1, 1999, ARCO Midcon, formerly ARCO Pipe Line Company ("ARCO"), exchanged its Line 63 assets for a 26.5% ownership interest in PPS and a note of $63.6 million. On June 7, 2001, ARCO made a capital contribution of $63.6 million to PPS, and PPS Holding Company ("Holdings"), a wholly owned subsidiary of Anschutz and the 100% owner of the General Partner, then purchased ARCO's ownership interest in PPS for $47.0 million in cash, and PPS repaid the $63.6 million note. This purchase of an additional ownership interest resulted in negative goodwill of $40.6 million, which was allocated proportionately to reduce property, plant and equipment of PPS.

The Line 63 system includes a 107-mile crude oil pipeline capable of shipping approximately 105,000 barrels of crude oil per day from the San Joaquin Valley to various refineries and delivery points in the Los Angeles Basin and in Bakersfield. The Line 63 System also includes storage assets, various gathering and distribution lines in the San Joaquin Valley, crude oil distribution lines in the Los Angeles Basin and a delivery facility in the Los Angeles Basin.

PMT was formed in June 2001, in connection with the purchase of certain assets in the San Joaquin Valley for approximately $14.4 million. The assets acquired consist of 122 miles of intrastate crude oil gathering pipelines and six storage and blending facilities with approximately 254,000 barrels of storage capacity and blending capacity of up to 65,000 barrels per day as well as a base stock of crude oil. The purchase price was allocated among the fair values of the assets acquired and no goodwill resulted from this acquisition. The purchase price is subject to adjustment based on operating cash flows (as defined in the purchase agreement) during the 24 months following the acquisition. Depending on the amount of this cash flow, the purchase price could decrease by up to $1.5 million or increase by up to $7.5 million. In addition, the seller remains liable for various indemnity, product supply and construction obligations undertaken in connection with the sale. PMT and the seller are engaged in discussions relating to the settlement of all obligations undertaken by them in connection with PMT's purchase of these assets.

RMP was formed in December 2001 in connection with the acquisition on March 1, 2002 of certain pipeline and related assets located in the Rocky Mountain region from an affiliate of BP plc for approximately $107.0 million. The pipeline and related assets acquired by RMP consist of various ownership interests in 1,925 miles of intrastate and interstate crude oil transportation pipelines, 209 miles of gathering pipelines and 29 storage tanks with approximately 1.4 million barrels of storage capacity. The purchase price was allocated among the fair values of the assets acquired and no goodwill resulted from this acquisition.

AREPI, which was transferred to PEG on July 12, 2002 in preparation for the Partnership's initial public offering, owns and operates a 42-mile crude oil pipeline with a throughput capacity of 52,500 barrels per day. The AREPI pipeline originates 21 miles south of Evanston, Wyoming at Ranch Station, Utah where it connects with the Frontier pipeline (discussed below) and terminates at Kimball Junction, Utah, where it connects with a ChevronTexaco pipeline that serves the Salt Lake City refineries.

RPL, which was transferred to PEG on March 1, 2002 in preparation for the Partnership's initial public offering, owns a 22.2% partnership interest in Frontier, a Wyoming general partnership, which owns Frontier pipeline. RPL owned a 12.5% partnership interest in Frontier until December 2001, at which time it acquired an additional 9.72% partnership interest from an affiliate of BP plc for $8.6 million. Frontier pipeline is a 290-mile pipeline with a throughput capacity of 62,200 barrels per day that originates in Casper, Wyoming and delivers crude oil to the AREPI pipeline and the Salt Lake City Core system.

Management Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires that management make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the balance sheet date as well as the reported amounts of revenue and expenses during the reporting period. The actual results could differ significantly from those estimates.

The Partnership's most significant estimates involve the valuation of individual assets acquired in purchase transactions, the useful lives of components of property and equipment, the expected costs of environmental remediation, and contingent liabilities.

Environmental Remediation

The Partnership accrues environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable in the future and may be reasonably estimated. These accruals are undiscounted and are based on information currently available, existing technology, the estimated timing of remedial actions and related inflation assumptions and enacted laws and regulations.

Revenue Recognition

The California Public Utilities Commission ("CPUC") economically regulates PPS's common carrier crude oil pipeline operations. All shipments on the regulated pipelines are governed by tariffs authorized and approved by the CPUC, and revenue is recognized when the transported crude oil volumes are delivered to a tariff destination point. Tariffs on Line 2000 are market-based, established based on market considerations subject to certain contractual restraints. Tariffs on Line 63 are cost-of-service based, developed based on the various costs to operate and maintain the pipeline as well as a charge for depreciation of the capital investment in the pipeline and an authorized rate of return.

AREPI and Frontier are common carriers under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). AREPI and Frontier transport crude oil under various cost-based tariff agreements at published rates, depending on the type and quality of the crude oil. RMP is a common carrier under the jurisdiction of both the FERC and the Wyoming Public Service Commission.

Pipeline transportation revenue is typically recognized upon delivery of the crude oil to the customer.

Crude oil sales are recognized as the crude oil is delivered to customers.

Transition Costs

Transition costs include one-time costs incurred in connection with the transition of the operations of acquired assets from the seller to the Partnership.

Derivative Instruments

The Partnership uses, on a limited basis, certain derivative instruments (principally futures and options) to hedge its minimal exposure to market price volatility related to its inventory of crude oil. The Partnership does not engage in speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying condensed consolidated balance sheets. Changes in the fair value of the Partnership's derivatives related to crude oil inventory are recognized in net income. For the three months ended March 31, 2003, revenues are net of $0.2 million related to changes in fair value of PMT's derivative instruments for its marketing activities.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under PEG's term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%).

As of March 31, 2003, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $8.2 million on the aggregate interest rate hedge, which is recorded as a liability at March 31, 2003. The $8.2 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.2 million, and a long term liability of $3.0 million. The unrealized loss reflecting the decline in interest rates from December 31, 2002, is shown in "other comprehensive income," a component of partners' capital, and not in the condensed consolidated income statement. Should interest rates remain unchanged from the March 31, 2003 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of approximately 7.00%.

By using derivative financial instruments to hedge exposures related to changes in market prices and interest rates, the Partnership exposes itself to market risk and credit risk. Market risk is the adverse effect on the value of a financial instrument that results from a change in interest rates, currency exchange rates or market prices. 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 failure of the counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty owes the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership owes the counterparty and, therefore, it does not possess credit risk. As of March 31, 2003, the counterparties to the interest rate swap agreements did not represent a credit risk to the Partnership as the fair value of each derivative agreement was negative.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. This review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. Estimates of expected future cash flows are to represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future cash flows exceed the carrying value of the asset, no impairment is recognized. If the carrying value of the asset exceeds the expected future cash flows, an impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. Any impairment provisions are permanent and may not be restored in the future.

Income Taxes

No provision for federal or state income taxes related to operations is included in the accompanying condensed consolidated financial statements. The Partnership is not a taxable entity and is not subject to federal or state income taxes as the tax effect of operations is accrued to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership's First Amended and Restated Agreement of Limited Partnership. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in the Partnership is not available to the Partnership.

In addition to federal and state income taxes, unitholders may be subject to other taxes, such as local, estate, inheritance or intangible taxes which may be imposed by the various jurisdictions in which the Partnership does business or owns property.

Net Income per Unit

Basic net income per limited partner unit is determined by dividing net income, after deducting the amount allocated to the general partner interest, by the weighted average number of outstanding limited partner units.

Diluted net income per limited partner unit is calculated in the same manner as basic net income per limited partner unit above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options and restricted units by application of the treasury stock method pursuant to Statement of Financial Accounting Standards No. 128 ("SFAS No. 128"), "Earnings per Share." For the three months ended March 31, 2003, the denominator of diluted net income per limited partner unit was increased by 69,873 units as compared to the denominator of basic net income per limited partner unit.

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS No. 123"), "Accounting for Stock-Based Compensation," the Partnership has elected to measure costs for restricted units and unit options using the intrinsic value method, as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation expense related to the restricted units has been recognized in the accompanying condensed consolidated financial statements over the vesting periods of the units and no compensation expense related to the

unit options has been recognized in the accompanying condensed consolidated financial statements. Had the Partnership determined compensation cost based on the fair value at the grant date for its unit options under SFAS 123, net income and earnings per limited partner unit would not have been materially reduced for the three months ended March 31, 2003.

Reclassifications

Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to reflect changes in the classification of certain expenses as operating or general and administrative due to the nature of such expenses. In addition, certain costs associated with crude oil purchases have been reclassified from operating expense to crude oil sales, net of purchases due to the nature of such costs. These reclassifications of prior year expenses conform to current year presentation.

Accounting Pronouncements

In January 2003, the FASB issued FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities." This interpretation clarifies the application of Accounting Research Bulletin No. 51 ("ARB 51"), "Consolidated Financial Statements," and requires companies to evaluate variable interest entities for specific characteristics to determine whether additional consolidation and disclosure requirements apply. This interpretation is immediately applicable for variable interest entities created after January 31, 2003, and applies to fiscal periods beginning after June 15, 2003 for variable interest entities acquired prior to February 1, 2003. The adoption of this interpretation did not have any impact on the Partnership's financial position or results of operations.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146 ("SFAS No. 146"), "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." It requires that a liability be recognized for those costs only when the liability is incurred, that is, when it meets the definition of a liability in the FASB's conceptual framework. SFAS No. 146 also establishes fair value as the objective for initial measurement of liabilities related to exit or disposal activities. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with earlier adoption encouraged. The adoption of this standard did not have any impact on the Partnership's financial position or results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145 ("SFAS No. 145"), "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The rescission of FASB Statement No. 4 ("Statement 4"), "Reporting Gains and Losses from Extinguishment of Debt," and FASB Statement No 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements," which amended Statement 4, will affect income statement classification of gains and losses from extinguishment of debt. Upon adoption, enterprises must reclassify prior period items that do not meet the extraordinary item classification criteria in Accounting Principles Bulletin No. 30, "Reporting the Results of Operations." The provisions of SFAS No. 145 related to the rescission of Statement 4 are applicable in fiscal years beginning after May 15, 2002, with early application encouraged. The provisions of SFAS No. 145 related to FASB Statement No. 13, "Accounting for Leases," are effective for transactions occurring after May 15, 2002, with early application encouraged. All other provisions of SFAS No. 145 are effective for financial statements issued on or after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 did not have any impact on the Partnership's financial position or results from operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The standard is effective for fiscal years beginning after June 15, 2002, with earlier adoption encouraged.

Effective January 1, 2003, the Partnership adopted SFAS No. 143, as required. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. A substantial portion of our assets have obligations to perform removal and/or remediation activities when the asset is retired. However, the fair value of the asset retirement obligation cannot be reasonably estimated, as the retirement dates are indeterminate. The Partnership will record such asset retirement obligation in the period in which the retirement dates are determined. The cumulative effect of adopting this standard did not have a material impact on the Partnership's financial position, results of operations or cash flows.

2. PENDING ACQUISITION

In February 2002, Holdings entered into an asset purchase agreement to acquire certain crude oil terminal and pipeline assets of Edison Pipeline and Terminal Company ("EPTC"), a division of Southern California Edison Company (the "ETPC Assets") for approximately $158.2 million, plus potential increases for certain pre-closing adjustments estimated to be between $5 million and $10 million. This acquisition is subject to approval of the CPUC and the satisfaction of other conditions. Although it is possible that CPUC approval could be received in the second quarter of 2003, it now appears more likely that a CPUC decision will not be issued until the third quarter. Holdings subsequently assigned its interest in the EPTC Assets to its wholly owned subsidiary, Pacific Terminals LLC. Under an agreement with the Partnership, Holdings has agreed to transfer all of its interest in Pacific Terminals LLC to the Partnership on or prior to the date the EPTC acquisition is closed.

The EPTC purchase agreement may be terminated by either party if the transaction has not been completed for failure of CPUC approval or other closing conditions by July 1, 2003. The Partnership anticipates that SCE will agree to extend the agreement if CPUC approval is not received by a date such that the transaction can be completed prior to the July 1 deadline.

3. INVESTMENT IN FRONTIER PIPELINE COMPANY

RPL owns a 22.22% partnership interest in Frontier which is accounted for under the equity method of accounting. Under the equity method, the investment is initially recorded at cost and subsequently adjusted to recognize the investor's share of distributions and net income or loss of the investee as they occur. Recognition of any such loss is generally limited to the extent of the investor's investment in, advances to, commitments and guarantees for the investee.

The summarized balance sheets of Frontier at December 31, 2002 and March 31, 2003 and the statements of income for the three months ended March 31, 2002 and 2003 are presented below:

Balance Sheets

	December 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Current assets	$ 4,481	$ 1,638
Property and equipment, net	9,252	9,175
Other assets	1	1

	December 31, 2002	March 31, 2003
	$ 13,734	$ 10,814
Current liabilities	$ 365	$ 441
Other liabilities	2,298	2,264
Partners' capital	11,071	8,109
	$ 13,734	$ 10,814

Statements of Income

	For the Three Months Ended	
	March 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Revenue	$ 3,416	$ 2,130
Operating expense	(573)	(508)
Depreciation expense	(83)	(89)
Operating income	2,760	1,533
Rate case litigation settlement	(1,600)	
Other income	45	4
Net income	$ 1,205	$ 1,537

4. RELATED PARTY TRANSACTIONS

During the three months ended March 31, 2002, the Predecessor paid a distribution to Anschutz of $6.0 million. During the three months ended March 31, 2003, the Partnership paid quarterly distributions to Anschutz of $9.9 million in respect of the fourth quarter 2002 on its common units, subordinated units and 2% general partner interest.

A subsidiary of Anschutz is a shipper on Line 2000 and is charged published tariff rates. The Partnership charged this subsidiary approximately $0.8 million and $0.4 million for the three months ended March 31, 2002 and 2003, respectively. This subsidiary entered into agreements with a third party to purchase crude oil, ship it on Line 2000, and sell it in the Los Angeles Basin. The amount associated with these shipments included in accounts receivable was $0.7 million at March 31, 2003. As an original sponsor of the Line 2000 project, Anschutz and its subsidiaries qualify for participating shipper tariff rates on the Line 2000 pipeline. Anschutz has designated its rights for participating shipper rates to the Partnership and other affiliates.

An affiliate of Anschutz is a shipper on AREPI pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million and $0.1 million during the

three months ended March 31, 2002 and 2003, respectively. The amount associated with these shipments included in accounts receivable was $0.1 million at March 31, 2003. An affiliate of Anschutz is a shipper on RMP pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million and $0.1 million during the three months ended March 31, 2002 and 2003, respectively. The amount associated with these shipments included in accounts receivable was $0.1 million at March 31, 2003.

Prior to April 1, 2002, Anschutz employed various personnel who worked directly on AREPI pipeline and provided other executive, accounting and administrative support to AREPI. Most of these employees continue to provide services to AREPI pipeline, but are now employed by the General Partner. During the three months ended March 31, 2002, Anschutz charged AREPI approximately $0.2 million for salaries of the pipeline related personnel and for various support services. No amounts were charged by Anschutz to AREPI in 2003.

RMP serves as the contract operator for Anschutz Wahsatch Gathering System, Inc. ("AWGS"), a wholly owned subsidiary of Anschutz that owns a natural gas gathering system in Wyoming and Utah. AWGS reimburses RMP for the direct costs of operating the AWGS assets, such as the salary and benefit costs incurred by the direct assigned field operating and maintenance personnel related to AWGS operations. In addition, AWGS pays an annual management fee of $0.3 million to reimburse RMP for the portion of time spent by management and for other overhead services related to AWGS activities. For the three months ended March 31, 2002 and 2003, amounts charged to AWGS represented one quarter of the annual management fee. The management fee charged for the month of March 2003 was included in the accounts receivable of RMP at March 31, 2003.

During 2002, Anschutz paid certain expenses on behalf of RMP. Amounts charged during 2002 for reimbursement were $0.3 million, which is included in "due to related parties" of RMP at March 31, 2003. In 2002, Anschutz also paid certain expenses on behalf of RPL. Amounts charged during 2002 for reimbursement were $0.4 million, which is included in "due to related parties" of RPL at March 31, 2003.

The Partnership does not have any employees. The General Partner employs approximately 215 employees who directly support the operations of the Partnership. All expenses incurred by the General Partner are charged to the Partnership. At March 31, 2003, amounts due to the General Partner for reimbursement of payroll and related costs amounted to $0.1 million.

In 2002, the Partnership began utilizing the financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership utilizes the services of Anschutz's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds are issued under Anschutz's bonding line. Out of pocket costs incurred by Anschutz for the benefit of the Partnership for computer consultants, insurance premiums and surety bond costs were reimbursed by the Partnership. In January 2003, Anschutz began charging the Partnership a fee of $0.1 million per year for these services and continues to charge the Partnership for any out of pocket costs it incurs. The fixed annual fee includes all license, maintenance and employee costs associated with the Partnership's use of the financial accounting system. Amounts accrued for the three months ended March 31, 2003 represent one quarter of the annual fee charged by Anschutz and were included in accrued expenses at March 31, 2003.

In 2002, Anschutz provided office space to several employees of the General Partner at no cost to the Partnership. Beginning in January 2003, the Partnership leased approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million, the prevailing market rate for comparable space. Amounts charged by an affiliate of Anschutz for the three months ended March 31, 2003 were included in "other liabilities" at March 31, 2003. Also beginning in 2003, the RMP's trucking operation began hauling water for an Anschutz oil and gas subsidiary at rates equivalent to those charged to third parties.

5. LONG-TERM DEBT

The Partnership's long-term debt obligations at December 31, 2002 and March 31, 2003 are shown below:

	December 31, 2002	March 31, 2003
	(in thousands)	
		(unaudited)
Senior secured revolving credit facility	$	$
Senior secured term loan facility	225,000	225,000
Total	225,000	225,000
Less current portion		
Long-term debt	$ 225,000	$ 225,000

	December 31, 2002	March 31, 2003

A $200.0 million revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the pending acquisition of the EPTC Assets (see Note 2, Pending Acquisition). The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders.

The revolving credit facility matures on July 26, 2007, at which time all outstanding amounts will be due and payable. The Partnership will be required to amortize amounts outstanding under the term loan facility on a quarterly basis at 1% per annum, with the first quarterly payment due September 2005. A 97% balloon payment will be due at maturity in July 2009.

PEG is the borrower under both the revolving credit facility and term loan facility, which are guaranteed by the Partnership and certain of PEG's operating subsidiaries. The revolving credit facility and the term loan facility are both fully recourse to PEG and the guarantors, but non-recourse to the General Partner. Obligations under the revolving credit facility and the term loan facility are secured by pledges of membership interests in and the assets of certain of PEG's operating subsidiaries.

Indebtedness under the revolving credit facility and term loan facility bear interest at PEG's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0% to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan facility) or (ii) LIBOR plus an applicable margin ranging from 1.25% to 2.50% for the revolving credit facility and ranging from 2.50% to 2.75% for the term loan facility. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. After the purchase of the EPTC Assets, the applicable margin will increase by a margin which ranges from 0.375% to 0.625% and will remain at that level for 270 days after the purchase or until the Partnership successfully concludes an equity offering that reduces certain ratios to specified levels, whichever is earlier. PEG incurs a commitment fee which ranges from 0.25% to 0.50% per annum on the unused portion of the revolving credit facility. Under the credit agreement, PEG is prohibited from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains certain financial covenants and covenants limiting the ability of PEG and certain of its subsidiaries to, among other things, incur or guarantee indebtedness, change ownership or structure, including consolidations, liquidations and dissolutions and enter into a new line of business. At March 31, 2003, PEG and its subsidiaries were in compliance with all such covenants.

At March 31, 2003, the Partnership had letters of credit totaling $1.4 million outstanding, for PMT activities, which were issued under PEG's $200.0 million revolving credit facility.

6. SEGMENT INFORMATION

The Partnership's business and operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations. Information regarding these two operating units is summarized below:

	West Coast	Rocky Mountain	Total
		(in thousands) (unaudited)	
Three Months Ended March 31, 2002			
Transportation revenues:			
Unaffiliated customers	$ 15,165	$ 4,965	$ 20,130
Affiliates	814	125	939
Crude oil sales, net	5,526		5,526
Depreciation and amortization	2,699	388	3,087
Operating income(1)	9,333	2,405	11,738
Capital expenditures	370	194	564

	West Coast	Rocky Mountain	Total
Identifiable assets	344,004	127,368	471,372
Three Months Ended March 31, 2003			
Transportation revenues:			
Unaffiliated customers	$ 15,445	$ 9,399	$ 24,844
Affiliates	447		447
Crude oil sales, net	5,659		5,659
Depreciation and amortization	2,822	1,359	4,181
Operating income(1)	10,723	3,342	14,065
Capital expenditures	370	190	560
Identifiable assets	349,824	137,247	487,071

(1) The following is a reconciliation of operating income as stated above to the statements of income, as general and administrative expenses are not allocated among the West Coast and Rocky Mountain operations:

	For the Three Months Ended	
	March 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Income Statement Reconciliation		
Operating income from above:		
West Coast Operations	$ 9,333	$ 10,723
Rocky Mountain Operations	2,405	3,342
Operating income from above	11,738	14,065
Less: General and administrative	1,342	3,982
Operating income	10,396	10,083
Other income	117	35
Interest income	185	56
Interest expense	(1,517)	(4,046)
Net income	$ 9,181	$ 6,128

7. COMMITMENTS AND CONTINGENCIES

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the Wyoming Public Service Commission ("WPSC") alleging that RMP's common stream rules and specifications and RMP's refusal to prohibit certain types of crude oil diluents from the common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. On April 21, 2003, the WPSC deliberated Sinclair's complaint and orally ruled that RMP will be required to adopt tariff language that prohibits certain types of crude oil diluents from the common stream or, in the alternative, that shippers who receive crude oil from the common stream that includes diluents be compensated for any disadvantage they suffer from the effects of the diluents. Until a written order is issued by the WPSC, which is not expected for several weeks, the Partnership cannot predict with any degree of certainty the effect of the WPSC's April 21, 2003 decision on the Partnership's operations. However, this ruling is not expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

On March 19, 2002, RMP filed revised tariffs that reduced the rates charged for interstate transportation service on the Western Corridor system. On April 15, 2002, Sinclair filed a complaint with the FERC challenging these rates. In its complaint, Sinclair alleged that the reduced rates exceeded just and reasonable levels. RMP filed a general denial of Sinclair's allegations, as well as a motion for dismissal of Sinclair's complaint and, alternatively, a motion asking the FERC to hold Sinclair's complaint in abeyance pending the FERC's decision on an application for market-based rates, which, if granted, would allow RMP to set its tariff rates in response to competitive forces, rather than by reference to cost of service. RMP and Sinclair are in discussions to resolve this matter. This matter is not expected to have an adverse effect on the Partnership's financial position, results of operations or liquidity.

The application for market based rates referenced in the preceding paragraph was filed by RMP on July 22, 2002. Protests to the application for market-based rates were filed with the FERC by Sinclair, Tesoro Refining and Marketing Company, ConocoPhillips and Chevron Products Company. These protests variously allege that the application incorrectly defined the relevant geographic and product markets and that, if such markets are properly defined, the Partnership would be found to have market power in those markets. On May 2, 2003, the FERC issued an order denying motions for summary disposition that had been filed by both parties and assigning an administrative law judge to hear the case. A pre-hearing conference has been scheduled for May 20, 2003. While being granted the right to set tariff rates for the Western Corridor on the basis of market considerations, rather than cost of service, would give RMP greater convenience and a desirable degree of pricing flexibility and responsiveness, a refusal by the FERC to grant such right would not be expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

The Partnership is subject to numerous federal, state and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The Partnership currently has an environmental remediation liability resulting from the acquisition of ARCO's interest in PPS in 2001. The accrued liability was $2.6 million at March 31, 2003 and was classified in the condensed consolidated balance sheets within "other liabilities." However, the total future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership's liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other parties.

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

8. SUBSEQUENT EVENT

On April 21, 2003, the Partnership declared a cash distribution of $0.4625 per limited partner unit, payable on May 15, 2003 to unitholders of record as of April 30, 2003.

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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, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are identified as any statements that do not relate strictly to historical or current facts, including statements that use terms such as "anticipate," "assume," "believe," "estimate," "expect," "forecast," "intend," "plan," "position," "predict," "project," or "strategy" or the negative connotation or other variations of such terms or other similar terminology. In particular, statements, express or implied, regarding our future results of operations or our ability to generate sales, income or cash flow or to make distributions to unitholders are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are based on management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve risks, uncertainties and assumptions. 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, blending, transporting, storing and distributing crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Risk Factors" contained in our annual report on Form 10-K for the year ended December 31, 2002. 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 statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P., the successor to Pacific Energy (Predecessor) (as defined below) should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the unaudited condensed consolidated financial position, results of operations and cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending assets, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets purchased from an affiliate of BP plc on March 1, 2002, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"). The financial data and results of operations for PPS, PMT, RMP, AREPI and RPL for the three months ended March 31, 2002, are presented on a combined basis and constitute the Predecessor. As a result of the initial public offering on July 26, 2002, the financial data and results of operations of PPS, PMT, RMP, AREPI and RPL for the three months ended March 31, 2003, are presented on a consolidated basis as successor to the Predecessor.

This discussion does not include any financial data from the pending acquisition of the Edison Pipeline and Terminal Company ("EPTC") assets which awaits regulatory approval. Although it is possible that CPUC approval could be received in the second quarter of 2003, it now appears more likely that a CPUC decision will not be issued until the third quarter. The EPTC purchase agreement may be terminated by either party if the transaction has not been completed for failure of CPUC approval or other closing conditions by July 1, 2003. The Partnership anticipates that SCE will agree to extend the agreement if CPUC approval is not received by a date such that the transaction can be completed prior to the July 1 deadline.

Critical Accounting Policies

Our condensed consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 1, Significant Accounting Policies, to our condensed consolidated financial statements), 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. The valuation of the fair value of the assets involves a number of judgments and estimates.

- We depreciate the components of our property and equipment on a straight-line basis over the estimated useful lives of the assets. The estimates of the assets' useful lives require our judgment and our knowledge of the assets being depreciated.

When necessary, the assets' useful lives are revised and the impact on depreciation is treated on a prospective basis.

We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated that cleanup costs are probable 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.

Overview

We are a Delaware limited partnership formed by The Anschutz Corporation ("Anschutz") in February 2002 to acquire, own and operate the midstream crude oil business and assets held by Anschutz and its subsidiaries. On July 26, 2002, we completed an initial public offering of common limited partner units for net proceeds of $151.3 million.

We are engaged in the business of gathering, blending, transporting, storing and distributing crude oil. We conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations. Our West Coast operations consist primarily of transporting crude oil produced in the San Joaquin Valley and the California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and Bakersfield through our two intrastate common carrier crude oil pipelines, Line 2000 and the Line 63 system. Our West Coast operations also include an intrastate proprietary crude oil gathering and blending system located in the San Joaquin Valley, through which we engage in the gathering, blending and marketing of crude oil that is generally delivered into our Line 63 system. Our Rocky Mountain operations consist of the Western Corridor system, the Salt Lake City Core system, AREPI pipeline and RPL's interest in Frontier pipeline.

We generate revenue primarily by charging a tariff for transporting crude oil on our pipelines. The amount of revenue we generate depends on the level of these tariff rates and the amount of throughput on our pipelines. The amount of throughput is dependent upon the availability of crude oil in the producing fields and the demand for the crude oil in the refining markets served by our pipelines. Our customers, or shippers, are primarily refiners that transport their crude oil on our pipelines for ultimate delivery to their refineries. Some of our customers are required under contracts with us to transport minimum volumes of crude oil annually.

The tariff rates are charged to the customer upon delivery of the crude oil to its ultimate delivery point. The tariff rates charged on Line 2000 and Line 63 are regulated by the California Public Utilities Commission ("CPUC"). Line 2000 has market-based tariff rates. Competition, as well as certain contractual limitations, determine the tariff rates we charge on Line 2000. Tariff rates on Line 63 are established using a cost-based methodology, which, among other things, allows for a regulated rate of return on the depreciated, historical cost of the assets. We also purchase crude oil produced in the San Joaquin Valley for subsequent blending, transportation and resale primarily in the Los Angeles Basin.

The tariff rates charged on AREPI pipeline and Frontier pipeline are regulated by the Federal Energy Regulatory Commission ("FERC") under a cost-based rate methodology. The FERC and the Wyoming Public Service Commission regulate tariffs on the Western Corridor and Salt Lake City Core systems on a cost-based methodology.

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way, insurance and depreciation, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of fuel and power used to run the various pump stations along our pipelines.

This report on Form 10-Q should be read in conjunction with the Partnership's annual report on Form 10-K for the year ended December 31, 2002.

Results of Operations

The table below sets forth certain unaudited segment operating results by regional operating unit for the three months ended March 31, 2003 and 2002:

	For the Three Months Ended,	
	March 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Segment Operating Income		
West Coast Operations:		
Pipeline transportation revenue:		
Unaffiliated customers	$ 15,165	$ 15,445
Affiliates	814	447
Total pipeline transportation revenue	15,979	15,892
Crude oil sales, net of purchases(1)	5,526	5,659
Net revenue before operating expenses	21,505	21,551
Expenses:		
Operating	9,407	8,006
Transition costs	66	
Depreciation and amortization	2,699	2,822
Total expenses	12,172	10,828
Operating income(5)	$ 9,333	$ 10,723
Operating Data:		
Pipeline throughput (bpd)(2)	168.5	159.3
Rocky Mountain Operations:		
Pipeline transportation revenue:		
Unaffiliated customers	$ 4,965	$ 9,399
Affiliates	125	
Total pipeline transportation revenue	5,090	9,399
Expenses:		
Operating	1,799	4,642
Transition costs	766	397
Depreciation and amortization	388	1,359
Total expenses	2,953	6,398
Share of net income of Frontier	268	341
Operating income(5)	$ 2,405	$ 3,342

For the Three Months Ended,

	For the Three Months Ended,	
	March 31, 2002	March 31, 2003
	(in thousands) (unaudited)	
Operating Data:		
Salt Lake City Core system throughput (bpd)(2)(4)	68.8	64.8
Western Corridor system throughput (bpd)(2)(4)	21.1	13.4
AREPI pipeline throughput (bpd)(2)	41.9	35.5
Frontier pipeline throughput (bpd)(2)(3)	39.8	35.3
Income Statement Reconciliation		
Operating income from above:		
West Coast Operations	$ 9,333	$ 10,723
Rocky Mountain Operations	2,405	3,342
Less: General and administrative(5)	1,342	3,982
Operating income	10,396	10,083
Other income	117	35
Interest income	185	56
Interest expense	(1,517)	(4,046)
Net income	$ 9,181	$ 6,128

(1) The above amounts are net of purchases of $59,929 and $86,622 for the three months ended March 31, 2002 and 2003, respectively.

(2) bpd is barrels per day.

(3) This figure represents 100% of the throughput on Frontier pipeline.

(4) This amount represents throughput for the month of March, 2002 and three months ended March 31, 2003, as this system was acquired from BP on March 1, 2002.

(5) General and administrative expenses are not allocated among the West Coast and Rocky Mountain operations.

Three Months Ended March 31, 2003 Compared to Three Months Ended March 31, 2002

Net Income. Consolidated net income totaled $6.1 million for the three months ended March 31, 2003 as compared to $9.2 million for the three months ended March 31, 2002, a decrease of $3.1 million, or 34%. The results for the three months ended March 31, 2002 are for a period prior to the Partnership's initial public offering in July 2002 and reflect a different capital structure than that of the results for the three months ended March 31, 2003. The Western Corridor system and the Salt Lake City Core system assets, which were acquired on March 1, 2002, contributed to net income for the three months ended March 31, 2003 compared to the month of March 2002. However, this increase was more than offset by an increase in interest expense of $2.5 million; and an increase in general and administrative expense of $2.7 million attributable to the significant growth experienced in 2002, costs associated with being a public company, and costs attributable to the long term incentive plan; and lower volumes for the West Coast and Rocky Mountains operations.

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $25.3 million for the three months ended March 31, 2003 compared to $21.1 million for the comparable period in 2002, an increase of $4.2 million, or 20%. This increase was attributable to our Rocky Mountain operations, where revenue increased by $4.3 million compared to the comparable period in 2002 due to revenue generated by the Western Corridor system and the Salt Lake City Core system assets, which were acquired on March 1, 2002. West Coast revenue for the three months ended March 31, 2003 was comparable to that for the three months ended March 31, 2002 as lower volumes were offset by a tariff rate increase in the second quarter of 2002.

Crude Oil Sales, net. The PMT gathering and blending system generated net revenue before operating expenses for the three months ended March 31, 2003 of $5.7 million on total sales of $92.3 million as compared to net revenue before operating expenses of $5.5 million on total sales of $65.5 million for the comparable period in 2002. The increase in total sales in 2003 is the result of increased crude oil prices. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expenses. Consolidated operating expenses totaled $12.6 million for the three months ended March 31, 2003 compared to $11.2 million for the comparable period in 2002, an increase of $1.4 million, or 13%. This increase was related primarily to our Rocky Mountain operations, where operating expenses increased by $2.8 million due to a full quarter of operations of the Western Corridor system and the Salt Lake City Core system assets compared to the one month of operations for the comparable period in 2002. Operating expenses for our West Coast operations decreased by $1.4 million primarily due to decreased right-of-way expenses resulting from the relinquishment of certain unused right-of-way and due to lower power expenses resulting from decreased volumes. West Coast power expenses did, however, increase on a per unit of consumption basis, and higher property and casualty insurance expenses partially offset the decreased expenses noted above.

Transition Costs. Consolidated transition costs were $0.4 million for the three months ended March 31, 2003 compared to $0.8 million for the comparable period in 2002, a decrease of $0.4 million, or 50%. Transition costs consisted of payments to BP for certain interim operations support and financial systems services related to the acquisition of the Western Corridor and Salt Lake City Core system assets and employee transition bonus payments.

General and Administrative Expense. Consolidated general and administrative ("G&A") expenses were $4.0 million for the three months ended March 31, 2003 compared to $1.3 million for the comparable period in 2002, an increase of $2.7 million, or 208%. This increase was primarily due to additional costs incurred as a result of the acquisition of the Western Corridor and Salt Lake City Core system assets on March 1, 2002, increased costs associated with being a public company, and higher expenses attributable to our long-term incentive plan.

Depreciation and Amortization Expenses. Consolidated depreciation and amortization expense was $4.2 million for the three months ended March 31, 2003, compared to $3.1 million for the comparable period in 2002, an increase of $1.1 million, or 35%. This increase consists of $1.0 million related to the acquisition of the Western Corridor system and the Salt Lake City Core system assets.

Interest Expense. Consolidated interest expense was $4.0 million for the three months ended March 31, 2003, compared to $1.5 million for the comparable period in 2002, an increase of $2.5 million, or 167%. This increase was due to an increase in the average daily debt balances, which were $225.0 million during the three months ended March 31, 2003, as compared to $205.4 million during the comparable period in 2002. Our current debt level reflects our post initial public offering capital structure. In addition, the interest rate on outstanding borrowings during the three months ended March 31, 2003 averaged 6.6% as compared to 3.0% during the comparable period in 2002.

Share of Net Income of Frontier. Our share of net income of Frontier was $0.3 million for the three months ended March 31, 2003, which was relatively unchanged from the comparable period in 2002.

Liquidity and Capital Resources

Historically, we have satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and from our credit facilities. We believe that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital

requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years. We expect to fund any future acquisitions with the proceeds of borrowings under our revolving credit facility and the issuance of additional units. Our ability to satisfy our debt service obligations, fund planned capital expenditures, make acquisitions and pay distributions to our unitholders will depend upon, among other things, our future operating performance. Our operating performance is primarily dependent on the volume of crude oil we transport, which could be affected by a decrease in the volume of crude oil produced from the oil fields or processed by the refineries served by our pipelines. These factors, which are affected by prevailing economic conditions in the crude oil industry and financial, business and other factors, some of which are beyond our control, could significantly impact future results.

On April 21, 2003, the Partnership declared a cash distribution of $0.4625 per limited partner unit, payable on May 15, 2003 to unitholders of record as of April 30, 2003.

Operating, Investing and Financing Activities

Net cash provided by operating activities was $5.9 million for the three months ended March 31, 2003 compared to $3.5 million for the comparable period in 2002, an increase of $2.4 million, or 69%. This increase was primarily associated with the changes in working capital items, partially offset by lower net income.

Net cash used in investing activities was $0.5 million for the three months ended March 31, 2003 compared to $96.6 million for the comparable period in 2002. The 2002 period included the acquisition of the Western Corridor system and Salt Lake City Core system assets on March 1, 2002. Capital expenditures were $0.6 million for the three months ended March 31, 2003, of which $0.3 million related to maintenance capital projects, $0.2 million related to expansion projects, and $0.1 million related to transition projects. Capital expenditures were $0.6 million for the three months ended March 31, 2002, of which $0.4 million related to maintenance capital projects and $0.1 million related to expansion projects and $0.1 million related to transition projects.

Net cash used in financing activities was $9.9 million for the three months ended March 31, 2003 compared to net cash provided by financing activities of $89.6 million for the comparable period in 2002. Cash used in financing activities for the three months ended March 31, 2003 consisted of distributions to the limited partners and general partner interests. Cash provided by financing activities for the three months ended March 31, 2002 consisted primarily of proceeds from a bank facility of $87.0 million used to fund the acquisition of the Western Corridor System and Salt Lake City Core system assets. Contributions of members and distributions to members during the three months ended March 31, 2002 were $8.7 million and $6.0 million, respectively.

Capital Requirements

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

- maintenance 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 to increase our transportation volumes and revenue.

We have budgeted total maintenance capital expenditures of $2.7 million and expansion capital expenditures of $0.4 million for 2003. These expenditures exclude any EPTC related capital expenditures.

Although it is possible that a CPUC decision regarding the pending EPTC acquisition could be received in the second quarter of 2003, it now appears more likely that a CPUC decision will not be issued until the third quarter. The purchase price for the EPTC assets is $158.2 million, plus potential increases for certain pre-closing capital expenditures and prepayments made by the seller relating to the purchased assets, and the value of displacement oil and warehouse inventory. We expect that these adjustments will be in the range of $5.0 million to $10.0 million. We intend to finance this acquisition initially from borrowings under our revolving credit facility, followed by the issuance of additional common units to repay a portion of the borrowings under our revolving credit facility.

Right-of-Way Obligations

We have secured various rights-of-way for our pipeline systems under right-of-way agreements, certain of which expire at various times through 2035, that provide for annual payments to third parties for access and the right to use their properties. Due to the nature of our operations, we expect to continue making payments and renewing the right-of-way agreements indefinitely. Annual amounts payable under certain of the right-of-way agreements are subject to fair market and inflation adjustments.

Right-of-way payments, which are included in operating expenses, were $1.4 million and $0.8 million during the three months ended March 31, 2002 and 2003, respectively.

Credit Facilities

The Partnership's long-term debt obligations at December 31, 2002 and March 31, 2003 are shown below:

	December 31, 2002	March 31, 2003
	(in thousands)	
		(unaudited)
Senior secured revolving credit facility	$	$
Senior secured term loan facility	225,000	225,000
Total	225,000	225,000
Less current portion		
Long-term debt	$ 225,000	$ 225,000

In connection with the completion of our initial public offering of common units, PEG entered into a new $425.0 million credit agreement with a syndicate of financial institutions led by Fleet National Bank, that provides for a five-year $200.0 million senior secured revolving credit facility and a seven-year $225.0 million senior secured term loan facility. On July 26, 2002, PEG borrowed $225.0 million under the term loan facility.

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the pending acquisition of the EPTC assets. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and distributions to unitholders. The revolving credit facility is currently undrawn except for letters of credit totaling $1.4 million at March 31, 2003.

The revolving credit facility matures on July 26, 2007, at which time it will terminate and all outstanding amounts will be due and payable. We are required to amortize amounts outstanding under the term loan facility on a quarterly basis at 1% per annum beginning in 2005, with the first quarterly payment due September 2005. A 97% balloon payment will be due at maturity in July 2009.

We may prepay all loans under the revolving credit facility at any time, and all loans under the term loan facility any time following the first anniversary of the closing of the facilities, without premium or penalty. Prepayment of the term loan facility during the first year will result in a 1% premium. Except as otherwise subsequently agreed by certain of the lenders, mandatory prepayments and commitment reductions will generally be required to reflect the net cash proceeds of asset sales not sold in the ordinary course of business and the net proceeds of new senior secured debt offerings, subject to certain exceptions.

The facilities are guaranteed by the Partnership and certain of PEG's subsidiaries. The facilities are fully recourse to PEG and the guarantors, but non-recourse to our General Partner. Obligations under the facilities are or will be secured by pledges of membership interests in and assets of PEG's subsidiaries, subject to certain limited exceptions and the approval of certain regulatory authorities.

Indebtedness under the facilities bear interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0% to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan facility) or (ii) LIBOR plus an applicable margin for the revolving credit facility ranging from 1.25% to 2.50% and the term loan facility ranging from 2.50% to 2.75%. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. After the purchase of the EPTC assets, the applicable margin will increase by a margin which ranges from 0.375% to 0.625% and will remain at that level for 270 days after the purchase or until we successfully conclude an equity offering that reduces certain ratios to specified levels, whichever is earlier. PEG will incur a per annum commitment fee margin which ranges from 0.25% to 0.50% on the unused portion of the revolving credit facility. The credit agreement prevents PEG from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. The credit agreement also contains covenants requiring PEG, including certain of its subsidiaries, to maintain specified financial ratios. In addition, the credit agreement contains other restrictive covenants.

In August and September 2002, PEG entered into interest rate swap agreements pursuant to which it hedged its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under the term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%). These interest rate swap agreements are described further in "Note 1 Summary of Significant Accounting Policies" in the accompanying condensed consolidated financial statements and "Item 3 Quantitative and Qualitative Disclosures About Market Risk" below.

Accounting Pronouncements

See discussion of newly issued accounting pronouncements in "Note 1 Summary of Significant Accounting Policies" in the accompanying condensed consolidated financial statements.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and crude oil price risk. Debt we incur under our credit facilities will bear variable interest at either the applicable base rate or a rate based on LIBOR. We have used and will continue to use certain derivative instruments to hedge our exposure to variable interest rates.

Although we generally do not own the crude oil that we transport in our pipelines, we purchase some crude oil in the San Joaquin Valley for subsequent blending, transportation and resale primarily in the Los Angeles Basin. We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our exposure to market price volatility related to our inventory of crude oil. We do not enter into speculative derivative transactions. The derivative instruments are included in other assets in the accompanying balance sheets. Changes in the fair value of our derivatives are recognized in net income. For the three months ended March 31, 2003 revenues are net of $0.2 million related to changes in the fair value of our derivative instruments for marketing activities.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under PEG's term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%).

As of March 31, 2003, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $8.2 million on the aggregate interest rate hedge, which is recorded as a liability at March 31, 2003. The $8.2 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.2 million, and a long term liability of $3.0 million. The unrealized loss reflecting the decline in interest rates from December 31, 2002, is shown in "other comprehensive income," a component of partners' capital, and not in the condensed consolidated income statement. Should interest rates remain unchanged from the March 31, 2003 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of approximately 7.00%.

We are subject to risks resulting from interest rate fluctuations as interest on the remaining $55.0 million outstanding under our term loan facility is based on variable rates. If the LIBOR rate were to increase 1.0% in 2003 as compared to the rate at March 31, 2003, our interest expense for 2003 would increase $0.6 million based on the $55.0 million outstanding on our term loan facility at March 31, 2003, which has not been hedged.

ITEM 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures.* Within 90 days before the filing of this report, Irvin Toole, Jr., our Chief Executive Officer, and Gerald A. Tywoniuk, our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures. Based on the evaluation, they believe that:

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and

Our disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) *Changes in internal controls.* There have been no significant changes in our internal controls or in other factors that could significantly affect our internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

See discussion of legal proceedings in "Note 7 Commitments and Contingencies" in the accompanying condensed consolidated financial statements.

ITEM 4. Submission of Matters to a Vote of Security Holders

None.

ITEM 6. Exhibits and Reports on Form 8-K

(a) Exhibits

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

Exhibit Number	Description
Exhibit 99.1	Certification of Chief Executive Officer of Pacific Energy GP, Inc., pursuant to 18 U.S.C. § 1350
Exhibit 99.2	Certification of Chief Financial Officer of Pacific Energy GP, Inc., pursuant to 18 U.S.C. § 1350

(b) Reports on Form 8-K:

Form 8-K as filed on February 3, 2003 to comply with Regulation FD (Fair Disclosure) requirements concerning additional information with respect to the Partnership's 4th quarter 2002 earnings release in January 2003.

Form 8-K as filed on May 1, 2003 concerning the Partnership's 1st quarter 2003 earnings release on May 1, 2003.

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SIGNATURES

Pursuant to the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, the Partnership has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PACIFIC ENERGY PARTNERS, L.P.

By: PACIFIC ENERGY GP, INC.
its General Partner

May 12, 2003

By: /s/ IRVIN TOOLE, JR.

Irvin Toole, Jr.
President, Chief Executive Officer and Director
(Principal Executive Officer)

May 12, 2003

By: /s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

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CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Irvin Toole, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pacific Energy Partners, L.P.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act rules 13a-14 and 15d-14) for the registrant and have:

a)

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

May 12, 2003

/s/ IRVIN TOOLE, JR.

Irvin Toole, Jr.
President and Chief Executive Officer
Pacific Energy GP, Inc.,
General Partner of
Pacific Energy Partners, L.P.

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CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Gerald A. Tywoniuk, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pacific Energy Partners, L.P.;

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

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

4.

The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act rules 13a-14 and 15d-14) for the registrant and have:

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

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

May 12, 2003

/s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
Pacific Energy GP, Inc.,
General Partner of
Pacific Energy Partners, L.P.

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