PACIFIC ENERGY PARTNERS LP
Form 10-K
March 15, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

**FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTIONS 13 OR 15(d)
OF THE SECURITIES AND EXCHANGE ACT OF 1934**

(Mark One)

ý **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 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**

31345
(Commission File Number)

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or jurisdiction of incorporation or organization)	**68-0490580** (I.R.S. Employer Identification No.)
5900 Cherry Avenue **Long Beach, California** (Address of principal executive offices)	**90805** (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Units representing limited partner interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class
None

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

The aggregate market value of the common units held by non-affiliates of the registrant (treating directors and executive officers of the registrant and holders of 10% or more of the common units outstanding, for this purpose, as if they were affiliates of the registrant) as of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, was $221,702,499, based on a price per common unit of $25.85, the closing price of the common units as reported on the New York Stock Exchange on such date. There were 14,441,763 of the registrant's common units and 10,465,000 of the registrant's subordinated units outstanding as of February 28, 2004.

Documents incorporated by reference: None.

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ITEM 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

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

Glossary of Terms

In addition, the following is a list of certain acronyms and terms used throughout the document:

ANS	Alaskan North Slope
Anschutz	The Anschutz Corporation
ARCO	ARCO Pipe Line Company
AREPI	Anschutz Ranch East Pipeline LLC
AWGS	Anschutz Wahsatch Gathering System, Inc.
bbl	Barrels
bpd	Barrels per day
CPUC	California Public Utilities Commission
dark products	Crude oil, refinery feedstocks such as gas oil, and heavy fuel oils
DOT	Department of Transportation
FERC	Federal Energy Regulatory Commission
Frontier	Frontier Pipeline Company
General Partner	Pacific Energy GP, Inc.
mbpd	One thousand barrels per day
OCS	Outer Continental Shelf
PEG	Pacific Energy Group LLC
PMT	Pacific Marketing and Transportation LLC
PPS	Pacific Pipeline System LLC
Predecessor	The group of entities consisting of PPS, PMT, RMPS and RPL, for which the financial data and results of operations are presented prior to the initial public offering on July 26, 2002
PT	Pacific Terminals LLC
RMPS	Rocky Mountain Pipeline System LLC
RPL	Ranch Pipeline LLC
SEC	Securities and Exchange Commission
SJV	San Joaquin Valley
WPSC	Wyoming Public Service Commission

Information Regarding Forward-Looking Statements

This annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). 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 Annual Report on Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing and distributing crude oil and other dark products and buying, gathering, blending and selling crude oil. Please see "Items 1 and 2 Business and Properties" below for a more detailed description of these risks and other factors that may affect the forward-looking statements. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Part I

ITEMS 1 and 2. Business and Properties

Overview

We are a publicly traded Delaware limited partnership formed in February 2002. On July 26, 2002, we completed an initial public offering of common units representing limited partner interests.

We are engaged principally in the business of gathering, transporting, storing, and distributing crude oil and other dark products in California and the Rocky Mountain region. We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing capacity in our storage facilities. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business. Information about us, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K that we file with, or furnish to, the Securities and Exchange Commission (the "SEC"), pursuant to Section 13(a) or 15(d) of the Exchange Act, are accessible, free of charge, on our website, www.PacificEnergyPartners.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. In addition, our code of ethics is available on our website.

We hold a 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose 100% owned subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor system, the Salt Lake City Core system, and AREPI pipeline, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership. Our AREPI pipeline was, until January 1, 2004, owned by Anschutz Ranch East Pipeline LLC, which had been a 100% owned subsidiary of PEG until its statutory merger into RMPS on that date.

We are managed by our General Partner, Pacific Energy GP, Inc., a wholly owned indirect subsidiary of The Anschutz Corporation ("Anschutz").

We have organized our business operations into two regional operating units: West Coast operations and Rocky Mountain operations.

West Coast Operations

Our West Coast operations, located in California, consist of pipelines that transport crude oil produced from California's San Joaquin Valley and the California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. Our pipelines are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields, Point Arguello and the Santa Ynez Unit, to the Los Angeles Basin and Bakersfield. In addition, on July 31, 2003, PT completed the acquisition of the storage and pipeline distribution system assets of Edison Pipeline and Terminal Company ("EPTC"), which was a division of Southern California Edison Company ("SCE"). These assets comprise our Pacific Terminals storage and distribution system. Our West Coast operations are headquartered in Long Beach, California, with a field office in Bakersfield.

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

- *Line 2000*
- *Line 63 System*
- *PMT Gathering and Blending System*
- *Pacific Terminals Storage and Distribution System*

Recent Developments. We recently completed a feasibility study with respect to the development of a new deepwater petroleum import terminal and related storage and pipeline distribution facilities to handle marine receipts of crude oil and feedstocks in the Port of Los Angeles (the "Pier 400 Project") and will proceed with the next phase of development. The Pier 400 Project will be subject to environmental permitting requirements and will require approvals from a variety of governmental agencies, including the Board of Harbor Commissioners, various agencies of the City of Los Angeles and the Los Angeles City Council. We have also entered into a project development agreement with two subsidiaries of Valero Energy Corporation that provides for a long-term volume commitment to support the project. The agreement is subject to satisfaction of various conditions, including completion of a mutually satisfactory terminalling services agreement. In addition, we have agreed with the Port of Los Angeles to begin the review process required by the California Environmental Quality Act ("CEQA"). Completion of construction and start up of the project is targeted for late-2006. For further discussion of the Pier 400 Project, see "West Coast Operations" below.

Rocky Mountain Operations

Our Rocky Mountain operations consist of pipelines that transport crude oil produced in Canada and the Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. Our pipelines deliver crude oil to refineries by direct connection or indirectly through connections with third party pipelines. Our Rocky Mountain operations are headquartered in Denver, Colorado, with five field offices in Wyoming. Our Rocky Mountain operations are comprised of our interest in the following assets, which form an integrated pipeline network:

- *Western Corridor System*
- *Salt Lake City Core System*
- *Frontier Pipeline*
- *AREPI Pipeline*

Recent Developments. On February 23, 2004, we entered into a definitive share purchase and sale agreement to acquire the Rangeland Pipeline System from BP Canada Energy Company. The Rangeland Pipeline System, which is located in the province of Alberta, Canada, consists of Rangeland Pipeline Company, Rangeland Marketing Company and Aurora Pipeline Company Ltd. The acquisition price for the Rangeland Pipeline System is $130 million (Canadian) plus an estimated $26 million (Canadian) for linefill, working capital, transaction costs and transition capital expenditures. At an exchange rate of $1 U.S. = $1.3187 Canadian, as of March 8, 2004, the total purchase price would be approximately U.S. $118 million. Closing of the transaction is expected in the second quarter of 2004, following receipt of regulatory approvals and fulfillment of other customary closing conditions.

Concurrently, we entered into a non-binding letter of intent to purchase the Mid Alberta Pipeline ("MAPL") assets, also in Alberta, from Imperial Oil Resources. This transaction is subject to completion of a definitive purchase and sale agreement, receipt of regulatory approvals and fulfillment of such closing conditions as may be included in such purchase and sale agreement. The transaction is expected to close in the second quarter of 2004.

For further discussion on these purchases see "Rocky Mountain Operations" below.

Business Strategy

Our principal business objective is to achieve sustainable long-term growth of cash distributions to unitholders by being a leading provider of pipeline transportation and other midstream services to the North American energy industry, while operating safely, protecting the environment and the communities in which we operate, and maintaining the operational integrity of our pipelines. We seek to realize our business objective by executing the following strategies:

Use our strategic position in our core market areas to maximize throughput on our pipelines and utilization of our storage facilities. As the owner and operator of the only two common carrier crude oil pipelines transporting crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields, to the Los Angeles Basin and to Bakersfield, we believe that we are well positioned to capitalize on the changing and growing needs of the refineries that serve California, the largest gasoline market in the United States. We continually seek opportunities to increase the crude oil throughput on our pipelines. We believe that the strategic position of our California pipelines creates other expansion and development opportunities that will help us maintain and increase our cash flows.

Our pipelines serve the major markets in the Rocky Mountain region, which continue to have a growing population and an increasing demand for refined products. Our Rocky Mountain area pipeline network is strategically situated to take advantage of increasing crude oil production in Canada and growing demand for refined projects in Salt Lake City and throughout the Rocky Mountain region. We believe crude oil throughput on our pipelines and our revenue will increase as refinery demand in the region continues to grow and Canadian crude oil and synthetic crude oil make up for a continuing decline in crude oil produced in the Rocky Mountain region.

Control our operating and capital costs while maintaining the safety and operational integrity of our assets. We focus on managing our costs, while fulfilling our responsibility to operate safely, to protect the environment and communities in which we operate, and to maintain the operational integrity of our assets.

Pursue strategic and accretive acquisitions and new projects that enhance and expand our core business. We intend to pursue acquisitions of additional midstream assets, including pipelines and storage and terminal facilities that are accretive to our cash flow and complement our existing business, with an emphasis on opportunities where supply and demand imbalances exist or where demand is not being met. We believe midstream assets will continue to be available for purchase as the major integrated energy companies divest noncore assets. We have three principal objectives in pursuing acquisitions:

- provide for long-term growth;
- strengthen and enhance our two existing regional operating units; and
- expand outside our two regional operating units into new growth areas.

We will also seek to capitalize on the experience of Anschutz and PPS in the development and construction of new midstream projects, such as our Pier 400 Project, that are complementary to our core market assets. Anschutz's experience includes construction of the Frontier and AREPI pipelines, and the more recent construction, in concert with PPS, of Line 2000.

We have been successful in the execution of this strategy of acquisition and development over the past several years and believe our acquisition history, reputation and new projects experience, along with the experience of Anschutz, will provide us with attractive opportunities in the future. The following are past successes which demonstrate the experience of Anschutz and Pacific Energy Partners in acquisition and development:

- in February 1999, the completion of the construction of Line 2000 at a cost of approximately $275 million;
- in May 1999, the acquisition of the Line 63 system in exchange for an interest in PPS;
- in June 2001, the acquisition of the outstanding ownership interest in PPS, increasing our ownership of PPS to 100%, for approximately $47 million;
- in June 2001, the acquisition of the PMT gathering and blending system for approximately $14 million;
- in December 2001, the acquisition of an additional 9.72% partnership interest in Frontier, increasing our ownership interest to 22.22% from 12.5%, for approximately $9 million;
- in March 2002, the acquisition of the Western Corridor and Salt Lake City Core systems, for approximately $107 million; and
- in July 2003, the acquisition of the Pacific Terminals storage and distribution system for approximately $173 million.

Minimize our exposure to commodity price volatility. We have historically managed our business to minimize our direct exposure to volatile commodity prices and, with the exception of our crude oil buying, gathering, blending and selling activity, which represents a small percentage of our revenue, we do not take title to the crude oil we transport on our pipelines and store in our storage facilities. We believe this strategy will enhance our ability to make cash distributions to our unitholders.

West Coast Operations

Recent Developments

In February 2004, we completed a feasibility study for the development of a new deepwater petroleum import terminal in the Port of Los Angeles ("POLA") to handle marine receipts of crude oil and feedstocks and are proceeding with the next phase of development. We also entered into a project development agreement with two subsidiaries of Valero Energy Corporation that provides for a 30 year, 50,000 bpd commitment from Valero to support the project. The Valero agreement is subject to satisfaction of various conditions, including completion of a mutually satisfactory terminalling services agreement. In addition, we and the POLA have identified several possible sites for construction of storage facilities by us and have agreed to begin the review process required by the California Environmental Quality Act ("CEQA").

If the Pier 400 Project is successfully developed, the new deepwater berth and related storage facilities will be constructed at Pier 400 and Terminal Island in the POLA, and a new pipeline distribution system will be constructed to connect the terminal facilities to Valero's Wilmington refinery and to other customer facilities through our existing storage and distribution system in the Los Angeles Basin. The Pier 400 Project would provide marine receipt facilities with water depth of approximately 81 feet, capable of handling some of the largest tankers, and with the capacity to efficiently accommodate increasing volumes of water borne imported crude oil and refinery feedstocks.

The deepwater berth at Pier 400 would be constructed by the POLA. If the project receives the required permits and approvals, we would construct the oil transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels, storage tanks with an initial capacity of 1.5 million barrels, and the pipeline distribution system, at an estimated cost of approximately $130 million, subject to final permitting requirements. Initially, the terminal is expected to handle marine receipts of approximately 100,000 bpd. However, the project is being designed to accommodate up to 250,000 bpd. Completion of construction and start up of the project is targeted for late-2006.

In addition to environmental permits, the project will require regulatory approvals from a variety of governmental agencies, including the Board of Harbor Commissioners, the City of Los Angeles and the Los Angeles City Council.

We spent approximately $5.3 million on the project in 2003. Additional capital expenditures of up to $5 million are budgeted during 2004.

We anticipate funding pre-construction costs through mid-2005 from our existing revolving credit facility, and with proceeds from the issuance of additional partnership units, including common units. Construction of the terminal facility is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Market Overview

General Market Considerations. The market in Southern California for our pipelines and storage facilities is influenced by the operation of the refineries in the central coast, Bakersfield and Los Angeles Basin areas. The operational levels and maintenance schedules of the refineries in our operating locations impacts demand for shipment of and storage of crude oil and other dark products in our pipelines and storage facilities. Major maintenance activities of the refineries in the Los Angeles Basin can result in reduced demand for our pipeline transportation services and increased demand for our storage services.

Sources of Demand. Refined products such as gasoline, diesel fuel, jet fuel and heating oil are derived from crude oil. Demand for refined products directly impacts the demand for crude oil. California consumes the most gasoline of any state and more jet fuel than any other state except Texas. In addition to meeting intrastate demand, California refineries export refined products to the Arizona and Nevada markets.

California refineries have a combined crude oil refining capacity exceeding 1.9 million bpd, ranking the state third highest in the nation. The California refineries were designed to process San Joaquin Valley ("SJV") heavy crude oil and higher sulfur California Outer Continental Shelf ("OCS") crude oil, which are both transported by our pipelines. Approximately 63% of this refining capacity, or 1.2 million bpd, is in the Los Angeles Basin and Central California areas that are served by our pipelines.

Sources of Supply. California has three main refining centers, located in the Los Angeles Basin, Central California and San Francisco, with the Los Angeles Basin refineries comprising approximately one-half of the state's capacity. California's refineries currently process approximately 1.9 million bpd of crude oil. In addition to the local California-produced crude oil, major ports in San Francisco and Los Angeles receive waterborne Alaskan North Slope ("ANS") and foreign crude oil. The three California refining centers compete for various supplies of crude oil, including crude oil that is produced in the fields we currently serve. To the extent crude oil from the areas we serve is diverted to the San Francisco refineries, the refineries we serve will be required to obtain their crude oil from supplies that are not transported on our pipelines.

Shell Oil Company recently announced that it would close its Bakersfield, California refinery by October 1, 2004, an event that we have projected will result in an increase in supply of crude oil available for transportation on our pipelines. There is no assurance that Shell's Bakersfield refinery will in fact be shut down or if there is such a shut down, when it will occur. Certain elected officials in California have recently expressed concern about the proposed shutdown and have stated that Shell should be required to try to find a buyer for the refinery that would keep it operating.

We expect that there will continue to be natural production declines from the California fields we serve as the underlying reservoirs are depleted. In addition, declining ANS production may impact us in the future if shippers elect to replace ANS crude oil for the San Francisco refineries with crude oil produced in the San Joaquin Valley and California Outer Continental Shelf.

We expect that with the natural production declines from the California fields we serve, there will be growth of imports transported by marine vessels to the Los Angeles Basin. With the recent acquisition of our Pacific Terminals storage and distribution system and our development of the planned Pier 400 Project, we expect that we will be able to participate in this growth.

Line 2000

General. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that transports crude oil produced in the San Joaquin Valley and California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, insulated trunk pipeline originating at our Emidio Pump Station in Kern County, California. Line 2000 delivers crude oil directly and indirectly to refineries and terminal facilities in the Los Angeles Basin, and because Line 2000 is insulated, the heavy crude oil can be transported on Line 2000 without re-heating or diluting it.

The design throughput capacity of Line 2000 is approximately 145,000 bpd and the permitted annual throughput capacity is 130,000 bpd. In 2003, approximately 81,700 bpd were transported on Line 2000. Line 2000 is capable of transporting multiple batches and grades of heavy crude oil. Construction of Line 2000 began in July 1997 and was completed approximately 19 months later, in January 1999.

Line 2000 currently transports SJV heavy crude oil, California OCS crude oil and mid-barrel crude oil. In 2003, 67% of the crude oil transported on Line 2000 was SJV heavy crude oil, 22% was California OCS crude oil and 11% was mid-barrel crude oil. SJV heavy crude oil and mid-barrel crude oil are received at our Emidio Pump Station. California OCS crude oil is received from Plains All American Pipeline at Pentland Station in Kern County, California and transported to Emidio Pump Station through a pipeline we lease from a third party.

Tariffs. The California Public Utility Commission ("CPUC") regulates tariffs on Line 2000. The tariff rates we charge shippers on Line 2000 are market-based rates, subject to certain contractual limitations. We review our tariff rates on an annual basis and, subject to certain limitations set forth in our long-term transportation agreements, may raise our tariff rates in response to increases in various inflation-based indices and market factors.

The Line 63 System

General. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1.2 million barrels of storage capacity. These storage assets, the majority of which are located in the San Joaquin Valley, are used primarily to facilitate the transportation of the crude oil on the Line 63 system. Line 63 has a throughput capacity of approximately 105,000 bpd. In 2003, approximately 69,300 bpd were transported to the Los Angeles Basin on Line 63.

Line 63 transports California OCS crude oil and multiple grades of SJV light crude oil, but does not transport any heavy crude oil. We receive California OCS crude oil from the Plains All American Pipeline at Pentland Station in Kern County, California and SJV light crude oil at various receipt locations along the Line 63 gathering system. Line 63 transports crude oil for third-party shippers as well as crude oil received from our PMT gathering and blending system.

Tariffs. The CPUC regulates tariffs on the Line 63 system. The tariff rates we charge shippers on Line 63 are cost-of-service based. Cost-of-service based rates are developed and based upon the various costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return.

PMT Gathering and Blending System

General. In addition to our primary pipeline operations, we are engaged in buying, gathering, blending and selling crude oil, activities that are complementary to our pipeline transportation business. Our PMT gathering and blending system is located in the San Joaquin Valley and consists of 103 miles of gathering pipelines as well as truck off-loading and blending facilities at six locations along our gathering system. Our PMT facilities have a total of approximately 0.3 million barrels of storage capacity and up to 65,000 bpd of blending capacity. A substantial portion of this system was constructed in 1983.

The primary functions of our PMT operations are buying, gathering and blending various grades of crude oil and natural gasoline, then transporting the blended product on Line 63 for sale to Los Angeles Basin refiners. These functions support our pipeline transportation business, in that this supply of crude oil would otherwise be available to other shippers to potentially move north to San Francisco as discussed in the section titled "Competition" below. We contract for third-party trucks to collect crude oil from remote areas that are not connected to our gathering system. In 2003, we gathered and blended approximately 24,600 bpd of crude oil. The blended crude oil is transported on Line 63 and sold in the Los Angeles Basin. An additional 4,800 bpd of trucked crude oil was gathered and delivered without blending to customers in the Los Angeles Basin or in the San Joaquin Valley. We generate net revenue from our blending activity by capturing the difference in price between the lower grade crude oil and the higher grade, blended crude oil. We believe that we are one of the largest blenders of SJV crude oil.

Generally, we purchase only crude oil for which we have a corresponding sale agreement for physical delivery of the crude oil to a third party. Through this process, we seek to maintain a position that is substantially balanced between crude oil purchases and future delivery obligations. We do not acquire and hold crude oil futures contracts or enter into other derivative contracts for the purpose of speculating on crude oil prices. Crude oil hedging is conducted on a limited basis to protect our inventory positions from major changes in market prices.

Rates. Our PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the Federal Energy Regulatory Commission ("FERC").

Pacific Terminals Storage and Distribution System

General.

On July 31, 2003, PT completed the acquisition of the EPTC storage and pipeline distribution system assets from SCE. These assets, which now comprise the Pacific Terminals storage and distribution system, complement our existing pipeline operations and form what we believe is one of the most extensive storage and pipeline distribution systems in southern California, providing service to all major refineries in the Los Angeles Basin.

The storage assets acquired by PT include 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity approximately 6.7 million barrels are in active commercial service, 0.4 million barrels are used for "throughput" from marine vessels to other tanks and do not generate revenue independently, approximately 1.7 million barrels are idle but could be reconditioned and brought into service, approximately 0.2 million barrels are in displacement oil service. In addition, PT acquired 17 storage tanks with a total of approximately 0.4 million barrels of storage capacity that are out of service. We have no current plans to bring these tanks into service. We use the Pacific Terminals storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin.

PT's pipeline distribution assets consist of 70 miles of distribution pipelines that are in active service and 49 miles of pipelines that are out of service. The active pipelines connect the PT storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. An agreement, which expires in October 2005, that provides for the use of a third-party dock in the Port of Long Beach enables PT to both receive imported foreign crude oils from and export refinery feedstocks to marine tankers. PT is capable of loading and off-loading marine shipments at a rate of 20,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, PT can deliver crude oil and feedstocks from its storage facilities to the refineries it serves at rates of up to 6,000 barrels per hour.

PT generates revenue primarily by leasing storage tank capacity to major refiners in the Los Angeles Basin. Lease rates for storage tanks are negotiated with each customer, resulting in private contracts varying in length from approximately one month to several years, generally with automatic renewal provisions. The customer contracts generally provide for throughput and heating charges, depending on the customer's specific needs.

Rates. The rates charged by PT for its storage and distribution services are regulated by the CPUC. The CPUC has authorized PT to establish the terms, conditions and charges for its storage and distribution services through negotiated contracts with its customers.

Customers

Each of the following customers represent greater than 10% of net revenue for our West Coast operations for 2003: ChevronTexaco; ExxonMobil Refining and Supply Company; Shell Trading Company and Valero Marketing and Supply Company. We have ship or pay agreements, expiring in 2009, with two customers, ChevronTexaco and Shell Trading Company, whereby they have committed to ship minimum volumes on Line 2000 that represent approximately 73% of their actual 2003 volumes transported on Line 2000. These agreements mitigate the potential adverse consequences of our concentration of customers.

Competition

Generally, pipelines are the lowest cost method for land-based transportation of crude oil over long distances. Therefore, our principal competitors for large volume shipments in the areas we serve are other pipelines. Competition among common carrier pipelines is based primarily on transportation charges, access to crude supplies and customer demand for crude oil. Line 2000 and Line 63 are currently the only common carrier crude oil pipelines that transport crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields to the Los Angeles Basin and Bakersfield. However, ExxonMobil owns and operates a proprietary crude oil pipeline from the San Joaquin Valley to its refinery in the Los Angeles Basin. This pipeline has historically operated at or near capacity. While it currently transports only ExxonMobil's crude oil, it is possible for this pipeline to become a common carrier that could compete for third-party shipments of crude oil to the Los Angeles Basin. We believe high capital requirements, stringent environmental laws and regulations and the difficulty of acquiring rights-of-way and related permits make it difficult for third parties to build new pipelines in the areas we serve in California.

Line 2000 and the Line 63 system serve refineries in the Los Angeles Basin and in Bakersfield. The shippers that use our pipelines also compete with refiners in the San Francisco Bay and the central California areas for crude oil produced in the San Joaquin Valley and the California Outer Continental Shelf. Since the refiners in central California, including Bakersfield, do not have access to alternative supplies of crude oil and have the lowest transportation costs due to their proximity to the producing fields, they will usually outbid other end-users, including San Francisco Bay and Los Angeles Basin refiners, to fulfill their requirements. As a result, the San Francisco Bay and the Los Angeles Basin refiners must compete for the remaining supply of available crude oil. SJV crude oil transported to San Francisco results in a reduction in the amount of crude oil available for transportation on our pipelines. Our throughput and revenue will be adversely affected to the extent more SJV crude oil is transported to San Francisco rather than to the Los Angeles Basin. In 2003, approximately 16% of all crude oil supplied to the Los Angeles Basin, including waterborne deliveries, was transported on Line 2000 and Line 63.

In addition, we face limited competition from trucks that deliver crude oil in several areas we serve. While truck transportation is not cost effective for long distance transportation, trucks can compete effectively for incremental and marginal volumes over shorter distances.

Our PMT operations face competition from other marketing companies as well as refineries and other end users, some of which may be our customers that purchase crude oil directly at the producing field.

Rocky Mountain Operations

Recent Developments

Rangeland Acquisition. On February 23, 2004, we entered into a definitive share purchase and sale agreement to acquire the Rangeland Pipeline System from BP Canada Energy Company. The Rangeland Pipeline System, which is located in the province of Alberta, Canada, consists of Rangeland Pipeline Company, Rangeland Marketing Company and Aurora Pipeline Company Ltd. The acquisition price for the Rangeland Pipeline System is $130.0 million (Canadian) plus an estimated $26.0 million (Canadian) for linefill, working capital, transaction costs and transition capital expenditures. At an exchange rate of $1 U.S. = $1.3187 Canadian, as of March 8, 2004, the total purchase price would be approximately U.S. $118 million. Closing of the transaction is expected in the second quarter of 2004, following receipt of regulatory approvals and fulfillment of other customary closing conditions.

The Rangeland Pipeline System, located in southern Alberta, is a proprietary system consisting of approximately 800 miles of gathering and trunk pipelines. It is a bi-directional system capable of gathering crude oil, condensate and butane and transporting these commodities either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S. border near Cutbank, Montana, where it connects to the Western Corridor system. The trunk system from Sundre Station to the U.S. border consists of approximately 221 miles of 12-inch pipe, with a 29 mile long 8-inch loop section, and has a current throughput capacity of approximately 85,000 bpd in light crude service.

MAPL Letter of Intent. Concurrently, we entered into a non-binding letter of intent to purchase the Mid Alberta Pipeline assets, also in Alberta, from Imperial Oil Resources. This transaction is subject to completion of a definitive purchase and sale agreement and fulfillment of such closing conditions as may be included in such purchase and sale agreement. The transaction is expected to close in the second quarter of 2004.

The 138-mile, 12-inch and 16-inch diameter MAPL pipeline is a proprietary pipeline system, with an estimated capacity in light crude service of approximately 50,000 bpd. The line originates at the Edmonton, Alberta oil hub and extends south to a connection with the Rangeland Pipeline System at Sundre Station.

Expansion Project. We are also undertaking a $3 million expansion of our pipelines serving Salt Lake City by establishing a new delivery connection from Frontier Pipeline to the Salt Lake City Core system. Existing pipelines into Salt Lake City are currently prorated, or limited by capacity, during the summer season. This connection will increase delivery capacity to Salt Lake City refineries by approximately 9,000 bpd. We are committed to keeping pace with growing demand for crude oil in this region and believe this new connection will be placed in service in the second quarter of 2004.

Market Overview

Sources of Demand. The Rocky Mountain region, which includes Montana, Wyoming, Colorado and Utah, is one of the fastest growing regions of the country in terms of overall population growth. We believe that this sustained population growth will result in an increase in the use of refined products and requirements for crude oil. The 16 refineries in the region consume more than 500,000 bpd of crude oil.

While we transport crude oil that is delivered throughout the Rocky Mountain region, Salt Lake City, Utah is one of our primary markets. Utah is one of the fastest growing states in the country and Salt Lake City is its most populous city. Among other factors, Salt Lake City's strong population growth is expected to stimulate growth in refined product demand, particularly gasoline and jet fuel. Additionally, Salt Lake City refiners supply refined products to markets in Utah, Wyoming, Idaho, Oregon, Washington and Nevada. Salt Lake City's refining center has a total capacity of 163,000 bpd.

Sources of Supply. The crude oil supplying the Rocky Mountain refining centers is a combination of Rocky Mountain and Canadian crude oil, including Canadian synthetic crude. We believe Rocky Mountain crude oil production will continue to decline and imports of Canadian crude oil, including synthetic crude, will increase to replace declining Rocky Mountain production.

One major source of the increase in crude oil production in western Canada is the increase in the production of Canadian synthetic crude oil. Canadian synthetic crude oil is produced from bitumen, a viscous substance abundant in the oil sand deposits in western Canada. Production of Canadian synthetic crude is expected to increase in the future, which will benefit our Rocky Mountain operations in two ways: first, there will be more Canadian synthetic crude destined for the Rocky Mountain refining centers served by our pipelines, and second, more Canadian crude oil should be transported on our pipelines as Canadian synthetic crude displaces it from current Canadian markets.

The agreement to acquire the Rangeland Pipeline system and the non-binding letter of intent to purchase the Mid Alberta Pipeline assets are a continuation of our regional development plans in the Rocky Mountains. When consummated, these acquisitions will allow us to participate in the expected increase in production of synthetic crude oil from the Alberta oil sands by providing to Canadian producers and U.S. Rocky Mountain refiners an integrated pipeline delivery system from Edmonton, Alberta to U.S. PADD IV markets.

Western Corridor System

General. We own an undivided interest in each of three contiguous pipelines that make up the Western Corridor system, an interstate and intrastate common carrier crude oil pipeline system. The Western Corridor system consists of 1,012 miles of pipelines extending from dual origination points at the Canadian border near Cutbank, Montana, where it receives deliveries from Rangeland pipeline and at Cutbank, Montana, where it receives deliveries from Cenex pipeline, terminating in Guernsey, Wyoming, with connections in Wyoming to Frontier pipeline, Suncor pipeline and our Salt Lake City Core system. Our ownership interest in each of the three pipelines comprising the Western Corridor system gives us rights to a specified portion of each pipeline's throughput capacity. The throughput capacity allocated to us is measured by reference to a volume of crude oil having certain viscosity characteristics; therefore our actual throughput capacity may be less than the figures specified below if the crude oil being transported is more viscous, or heavier, than that which is used as the benchmark to determine the amount of our throughput capacity. Conoco Pipe Line Company, the co-owner of the Western Corridor pipeline, owns the remaining undivided interest in each of these pipelines. In 2003, approximately 71% of the crude oil transported on our portion of the Western Corridor system's throughput capacity was Canadian crude oil and the remaining 29% was Rocky Mountain crude oil. Our portion of the Western Corridor system does not currently transport Canadian synthetic crude. The pipelines comprising the Western Corridor system were constructed at various times, with Glacier pipeline constructed in 1960, Beartooth pipeline in 1996 and segments of Big Horn pipeline in 1944 and 1996.

Each pipeline is described below:

Glacier Pipeline. We own a 20.8% undivided interest in Glacier pipeline, which provides us with approximately 25,000 bpd of throughput capacity. Glacier pipeline consists of 565 miles of two parallel crude oil pipelines, a 277-mile, 12-inch trunk pipeline and a 288-mile, 8-inch trunk pipeline, both extending from the Canadian border near Cutbank, Montana to Billings, Montana. Shipments on Glacier pipeline can be delivered either to refineries in Billings, Montana or into Beartooth pipeline. In 2003, approximately 11,700 bpd of Canadian crude oil was transported on our Glacier pipeline throughput capacity. Conoco Pipe Line Company is the operator of Glacier Pipeline.

Beartooth Pipeline. We own a 50% undivided interest in Beartooth pipeline, which provides us with approximately 25,000 bpd of throughput capacity. Beartooth pipeline is a 76-mile, 12-inch trunk pipeline from Billings, Montana to Elk Basin, Wyoming. All shipments on Beartooth pipeline are delivered into Big Horn pipeline. In 2003, approximately 8,500 bpd of Canadian crude oil was transported on our Beartooth pipeline throughput capacity. Beartooth pipeline was constructed to connect Glacier pipeline with Big Horn pipeline. We operate Beartooth pipeline.

Big Horn Pipeline. We own a 57.6% undivided interest in Big Horn pipeline, which provides us with approximately 33,900 bpd of throughput capacity. Big Horn pipeline consists of a 250-mile, 12-inch trunk pipeline from Elk Basin, Wyoming to Casper, Wyoming and a 121-mile, 12-inch trunk pipeline from Casper, Wyoming to Guernsey, Wyoming. Shipments on Big Horn pipeline can be delivered either to Wyoming refineries directly, into Frontier pipeline at Casper, Wyoming or into the Salt Lake City Core system at Guernsey, Wyoming. In 2003, approximately 8,500 bpd of Canadian crude oil and 5,000 bpd of Rocky Mountain crude oil was transported on our Big Horn throughput capacity. We operate Big Horn pipeline.

Under our contracts with Conoco Pipe Line Company, we manage our undivided interest in the Western Corridor system independently of Conoco Pipe Line Company. We set our own tariff rates, market our own capacity to shippers and account for our own revenue. This information is not shared with Conoco Pipe Line Company. We approve and monitor budgets and are allocated our share of the costs in accordance with our joint agreement.

We also own various undivided interests in 22 storage tanks that provide us with a total of approximately 1.3 million barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on our portion of the throughput capacity of the pipelines.

Tariffs. The FERC and the Wyoming Public Service Commission ("WPSC") each regulate various tariffs on the Western Corridor system. The tariff rates we charge shippers on the Western Corridor system are cost-of-service based tariffs at published rates, although competitive forces may limit such rates.

Salt Lake City Core System

General. We own 100% of and operate the Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the Rocky Mountain region primarily to refiners in Salt Lake City. The Salt Lake City Core system trunk pipelines have a combined throughput capacity of approximately 60,000 bpd to Salt Lake City. Of the 60,000 bpd delivery capacity into Salt Lake City, approximately 40,000 bpd is delivered directly through our pipelines and approximately 20,000 bpd is delivered indirectly through a connection to a ChevronTexaco pipeline. The Salt Lake City Core system consists of 913 miles of trunk pipelines, 209 miles of gathering pipelines and 29 storage tanks with approximately 1.4 million barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. The main trunk pipeline originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming, and extends west to Wamsutter, Wyoming, where it divides, with a northern segment continuing west, eventually delivering to Salt Lake City, and a southern segment extending south to Rangely, Colorado, where it delivers to a ChevronTexaco pipeline that serves Salt Lake City. In 2003, the northern segment delivered approximately 37,500 bpd and the southern segment delivered approximately 18,000 bpd to Salt Lake City. In addition, 9,900 bpd were transported from Reno to Casper, Wyoming and 300 bpd from Reno to Guernsey, Wyoming. In 2003, virtually all of the crude oil transported on the Salt Lake City Core system was Rocky Mountain crude oil. Construction of the Salt Lake City Core system began in 1939 with construction of additional pipelines and facilities continuing until 1991.

We also operate a trucking fleet that transports additional volumes for delivery into the Salt Lake City Core system. Our trucks transport crude oil owned by others from outlying producing fields throughout Wyoming, which for economic reasons, do not have a physical connection to one of our pipelines. The crude oil is gathered and then delivered to unloading stations along the Salt Lake City Core system. Our trucks also transport processed water for others from oil and gas wellheads to disposal sites. Our trucking operations do not represent a significant portion of our total revenue.

Tariffs. The FERC and the WPSC each regulate various tariffs on the Salt Lake City Core system. The tariff rates we charge on the Salt Lake City Core system are cost-of-service based tariffs at published rates, although competitive forces may limit such rates.

Frontier Pipeline

General. We own 22.22% of Frontier Pipeline Company, a general partnership that owns 100% of Frontier pipeline, and we serve as its operator. Enbridge, Inc., an unrelated third party, owns the remaining 77.78% of Frontier Pipeline Company. Frontier pipeline is an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd and three storage tanks with approximately 274,000 barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. Frontier pipeline originates in Casper, Wyoming, a hub for the distribution of crude oil produced in Canada and in the Rocky Mountain region, and receives deliveries from the Western Corridor system. Frontier pipeline also receives Canadian crude oil, including Canadian synthetic crude, via connections with Express pipeline, and other connecting carriers in Casper, Wyoming. Frontier pipeline also transports crude oil received from producing fields in Montana and northeast Wyoming through connections with the Salt Lake City Core system and third-party pipelines. Frontier pipeline delivers crude oil into the Salt Lake City Core system and to AREPI pipeline for ultimate delivery into Salt Lake City. In 2003, approximately 42,700 bpd were transported on Frontier pipeline. Frontier pipeline was constructed in 1983.

Tariffs. The FERC regulates tariffs on Frontier pipeline. The tariff rates we charge on Frontier pipeline are cost-of-service based tariffs at published rates, depending on the type and characteristics of the crude oil.

AREPI Pipeline

General. We own 100% of and operate AREPI pipeline, an interstate common carrier crude oil pipeline. AREPI pipeline consists of a 42-mile trunk pipeline with a throughput capacity of approximately 52,500 bpd and three storage tanks with approximately 100,000 barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. The trunk pipeline originates 21 miles south of Evanston, Wyoming at Ranch Station, Utah, receives deliveries from Frontier pipeline and terminates at Kimball Junction, Utah, where it delivers to a ChevronTexaco pipeline serving the Salt Lake City refinery market. At present, AREPI pipeline is the principal source of supply for this ChevronTexaco pipeline between Kimball Junction and Salt Lake City. AREPI pipeline is capable of transporting multiple grades of Canadian crude oil, including Canadian synthetic crude, as well as multiple grades of crude oil produced in the Rocky Mountain region. In 2003, approximately 42,700 bpd were transported on AREPI pipeline. AREPI pipeline was constructed in 1987.

Tariffs. The FERC regulates tariffs on AREPI pipeline. The tariff rates we charge on AREPI pipeline are cost-of-service based tariffs at published rates, depending on the type and characteristics of the crude oil.

Customers

Each of the following customers represent greater than 10% of net revenue for our Rocky Mountain operations for 2003: ChevronTexaco and Tesoro. We have not entered into any transportation contracts with respect to crude oil transported on the Rocky Mountain pipelines.

Competition

We compete against several crude oil pipelines in the Rocky Mountain region. Each pipeline is described below:

Express/Platte Pipeline. Express/Platte Pipeline delivers to Frontier pipeline at Casper, Wyoming and transports Canadian crude oil, including synthetic crude, into the Rocky Mountain region. Recently, Terasen Pipelines Inc., the owner of Express pipeline, announced its intent to proceed with expansion plans for the Express pipelines system. The expansion, which will increase the Express pipeline system's total capacity by 108,000 bpd, from 172,000 bpd to 280,000 bpd, is scheduled to be ready for service by April 2005;

Cenex Pipeline. The Cenex pipeline moves crude oil from Canada and Montana to refineries in Billings and Laurel, Montana. This pipeline can also receive or deliver Canadian crude oil to and from the Western Corridor system at the Cutbank, Montana station on Glacier pipeline;

Red Butte Pipeline System. The Red Butte pipeline system in eastern Wyoming gathers heavy crude oil in the same area of Wyoming, namely Elk Basin, as our Big Horn gathering system in central Wyoming;

Eastern Corridor System. The Eastern Corridor system, which delivers to the Salt Lake City Core system at Fort Laramie, Wyoming, is made up of pipeline systems that deliver crude oil from

Canada, eastern Montana and western North Dakota to customers in Wyoming, Colorado and Utah; and

Conoco Western Corridor. Conoco Pipe Line Company owns an undivided interest in the Glacier, Beartooth and Big Horn pipelines. Conoco Pipe Line Company sets its tariff rates, markets its throughput capacity, and accounts for its revenue separate from and in competition with us.

Construction of a refined products pipeline system able to deliver refined products from El Paso, Texas, into the Rocky Mountain region has been discussed by various companies for a number of years. The goal of such a pipeline would be to transport refined products from refineries on the Texas Gulf Coast to Salt Lake City via a series of connected pipeline segments. If built, such a pipeline would compete with our Rocky Mountain operations. Such a project would require significant modifications to existing pipelines as well as the construction of new pipelines. Based on the information currently known to us, there is presently little interest being expressed for such a pipeline and we do not believe it will be constructed in the near future.

We continue to face competition from trucks that transport crude oil produced in the Rocky Mountain region to local markets. We believe that despite their ability to transport incremental crude oil volumes from southwest Wyoming, trucks are not competitive for large volumes or longer distances. Moreover, we believe that the significance of truck competition will decline as Rocky Mountain crude oil production declines and is replaced by Canadian crude oil and synthetic crude.

Pipeline Operation and Control

All of our pipelines are operated, monitored and controlled through our operations control center located at our main office in Long Beach, California. Our operations control center houses the pipeline system controller consoles and the Supervisory Control and Data Acquisition ("SCADA") systems used to operate the pipelines. The assets comprising the PT storage and distribution system were operated from an operations control center in Dominguez Hills, California. The control center for these assets was relocated to our Long Beach Operations control center in October 2003.

We operate all of our pipelines and the Frontier pipeline from four consoles that are manned 24 hours a day by our pipeline system controllers. Our Long Beach control center is housed in a stand-alone building designed with special earthquake protection and multiple security systems to ensure that only authorized personnel enter. In addition, this facility has two uninterruptible power supplies to provide continuous power in the event of an external power failure. It is also equipped with fire detection and fire suppression systems.

In general, the SCADA systems we use provide operational data, including product-specific information such as viscosity and gravity, and operational information, such as pressure, temperature and flow rates, as well as information on the operational condition of pumps, valves, tanks and other status points on a continuous, real-time basis. In addition to continuous monitoring, our SCADA systems provide our pipeline system controllers with the ability to remotely control various aspects of systems operation, including starting and stopping pumps, opening and closing valves, and switching into and out of storage tanks.

Safety and Maintenance

Our pipelines are subject to regulation by the Department of Transportation ("DOT") under the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires pipeline operators to comply with regulations issued pursuant to HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 ("Pipeline Safety Act"), amends the HLPSA in several important respects. It requires the Research and Special Programs Administration of the DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In August 2000, the DOT adopted pipeline operator qualification rules requiring minimum qualification requirements for personnel performing operations and maintenance activities on hazardous liquid pipelines. The DOT has also approved regulations that require operators of pipelines in High Consequence Areas, such as densely populated or ecologically sensitive areas, to conduct risk assessments, utilize internal inspection devices or perform hydrotesting to assess pipeline integrity, and facilitate changes in operation and maintenance procedures to reduce the risk of public safety and environmental impacts.

The Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, imposes additional requirements on pipeline operators. The new act mandates, among other things, the delivery to the DOT of data that can be used in a national pipeline mapping system, the implementation of operator examinations and other qualification programs, periodic pipeline safety inspections, and increased civil penalties for violators. It also includes a whistleblower protection clause to protect line employees who reveal safety violations or operational flaws.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. Some of the states in which we operate, including California, have assumed such responsibility for intrastate pipelines. Our trucking operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials by motor vehicle. We believe that our pipeline and trucking operations are in substantial compliance with applicable operational and safety requirements. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

In California, our pipelines are subject to the Elder California Pipeline Safety Act of 1981, as amended, which in general implemented the HLPSA with respect to California intrastate pipelines and delegated responsibility for administration and enforcement of the HLPSA to the California State Fire Marshal. In addition, this act requires all pipelines to undergo a hydrostatic test or smart pig (electronic internal inspection) inspection every five years and requires the state fire marshal to maintain a list of all pipelines in the state that, because of the occurrence of certain types or numbers of reportable leaks during the previous three or five year period are considered to be "higher risk" pipelines. All pipeline segments that are included on the higher risk pipeline list are required to be tested more frequently than other pipelines, in some cases as often as annually. One 3.8 mile segment of our Line 63 system is included on the higher risk pipeline list. This segment has been internally tested as part of our smart pig program and, in the absence of additional reportable leaks, will be removed from the list in February 2005.

We perform preventive and normal maintenance on our pipelines and appurtenances and make repairs and replacements when necessary or appropriate. We also conduct routine and required inspections of our pipelines and other assets as required by law. We inject corrosion inhibitors into some of our pipelines to prevent internal corrosion. Cleaning and de-waxing devices, known as "pigs," are also run through most of our pipelines to help prevent internal corrosion, as further described below. External coatings and impressed current cathodic protection systems are used to protect against external corrosion on all trunk pipelines. We conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We continually monitor, test and record the effectiveness of these corrosion-inhibiting systems.

We monitor the structural integrity of selected segments of our pipelines through a program of periodic internal inspections using electronic internal inspection tools, or "smart pigs." These tools analyze the interior of our pipelines, providing data as to wall thickness, corrosion and other anomalies that might indicate possible pipeline failure. Our engineers conduct a detailed review of the inspection data and make repairs as required to ensure the integrity of the pipelines. We have developed an integrity management program in accordance with DOT regulations for assessing our pipelines and prioritizing future smart pig runs or other approved integrity test methods. We believe this program will enable us to give the highest priority in scheduling inspections or pressure tests for integrity to pipelines with higher potential risk to the environment or the public.

In the five years ended December 31, 2003, we have internally inspected 100% of our California trunk pipelines and 43% of our distribution lines. In our Rocky Mountain segment approximately 40% of the pipelines we operate have been smart pigged in the last five years.

The workplaces associated with our operations are subject to the requirements of the Federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes that regulate worker health and safety. In addition, some states, including California and Utah, have received authorization to implement their own occupational safety and health programs in lieu of the federal program. We have an ongoing, comprehensive safety training program for our employees and believe that our operations are in material compliance with applicable occupational health and safety requirements, including general industry standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Tariff Rate Regulation

Interstate Pipelines

General Federal Regulation. Our interstate common carrier crude oil pipeline operations are subject to tariff rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for crude oil pipelines, which for tariff rate purposes includes refined product pipelines, (crude oil and refined products pipelines are referred to collectively as "petroleum pipelines" in this section), be just and reasonable and non-discriminatory. The Interstate Commerce Act permits challenges to proposed new or changed tariff rates by protest and challenges to tariff rates that are already on file and in effect by complaint. Upon the appropriate showing, a successful complainant may obtain damages or reparations for generally up to two years prior to the filing of a complaint.

The FERC is authorized to suspend the effectiveness of a new or changed tariff rate for a period of up to seven months and to investigate the rate. If, upon the completion of an investigation, the FERC finds that the rate is unlawful, it may require the pipeline operator to refund to shippers, with interest, any difference between the rates the FERC determines to be lawful and the rates under investigation. In addition, the FERC may order the pipeline to change its tariff rates prospectively to the lawful level. In general, and except as discussed below with respect to indexed and "grandfathered" rates, petroleum pipeline tariff rates must be cost-of-service based, although settlement rates, which are tariff rates that have been agreed to by all shippers, are permitted. Market-based tariff rates may be permitted in certain circumstances such as when the FERC determines that a particular transportation market is competitive.

The FERC has adopted a trended original cost methodology as the general methodology to be used in setting cost-of-service based tariff rates for petroleum pipelines. The trended original cost methodology is similar to the depreciated original cost methodology generally used by the FERC to set rates for natural gas pipelines and electric utilities, with the primary difference being that under the trended original cost methodology, the inflation component of the petroleum pipeline's equity return is extracted from the equity return and added to the pipeline's equity rate base. The write-up is then amortized over the life of the pipeline's property, similar to the recovery of depreciation.

Index-Based Rates, Energy Policy Act of 1992 and Grandfathered Rates. In October 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed interstate petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of the Energy Policy Act, or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest, or investigation during the 365-day period, to be just and reasonable under the Interstate Commerce Act. These tariff rates are commonly referred to as "grandfathered rates." The Energy Policy Act provides that a grandfathered rate may not be challenged by complaint except in the following limited circumstances:

a substantial change has occurred since enactment in either the economic circumstances of the oil pipeline that were a basis for the rate or the nature of the services that were a basis for the rate;

the complainant was contractually barred from challenging the rate prior to enactment of the Energy Policy Act and filed the complaint within 30 days of the expiration of the contractual bar; or

the rate is challenged as being unduly discriminatory or preferential.

The Energy Policy Act further required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. On October 22, 1993, the FERC responded to the Energy Policy Act directive by issuing Order No. 561, which adopted a new rate-indexing methodology for interstate petroleum pipelines. Under the resulting regulations, effective January 1, 1995, petroleum pipelines were able to change their rates within prescribed ceiling levels that are tied to changes in the producer price index for finished goods, minus one percent. Tariff rate increases made under the index are subject to protest, but the scope of the protest proceeding is limited to an inquiry into whether the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. The rate-indexing methodology is applicable to any existing tariff rate, whether grandfathered or whether established after enactment of the Energy Policy Act.

In Order No. 561, the FERC said that as a general rule pipelines must utilize the indexing methodology to change their tariff rates. Indexing includes the requirement that, in any year in which the index is negative, pipelines must file to lower their rates if they would otherwise be above the reduced ceiling. However, a pipeline is not required to reduce its grandfathered rates below the level deemed just and reasonable under the Energy Policy Act. Under the indexing regulations, a pipeline can request a rate increase that exceeds index levels under a cost-of-service approach only after establishing a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. The FERC also retained market-based rates and settlement rates as alternatives to indexing and the cost-of-service approach in certain specified circumstances.

The FERC indicated in Order No. 561 that it would assess every five years how the rate-indexing method was operating. The FERC conducted the first of such assessments in 2000. In an order issued December 14, 2000, the FERC concluded the existing index had closely approximated the actual cost changes in the petroleum pipeline industry and that use of the rate index continued to satisfy the mandates of the Energy Policy Act. The Association of Oil Pipe Lines petitioned for judicial review of that decision to the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), arguing that the annual adjustment should be based on the full producer price index, without the one percentage point deduction. On March 1, 2002, the D.C. Circuit found that the FERC had not provided adequate justification for retention of the existing rate-index and remanded the case to the FERC for further proceedings. On February 20, 2003, the FERC issued an order on remand in which it changed the rate index to the producer price index for finished goods, but without the one percentage point deduction. The FERC made the change on a prospective basis, however, it does allow oil pipelines to recalculate their maximum ceiling rates as though the new rate index had been in effect since July 1, 2001. A group of shippers have challenged the FERC's February 2003 order at the D.C. Circuit. We cannot predict whether that challenge will be successful; however, we do not expect it to have a material impact on our results of operations for 2004.

Recent Developments Regarding Petroleum Pipeline Rates. Another development affecting petroleum pipeline ratemaking arose in Opinion No. 397, involving Lakehead Pipe Line Company, L.P., a partnership that operates a crude oil pipeline. In Opinion No. 397, the FERC concluded that Lakehead was entitled to include in calculating its rates an income tax allowance only with respect to the portion of its earnings that are allocated to its partners that are corporations, rationalizing that income allocated to other partners would be subject only to one level of taxation. The parties subsequently settled the case, so there was no judicial review of the FERC's decision.

Two other FERC proceedings involving SFPP, L.P. ("SFPP") could result in changes to the FERC's decision in Opinion No. 397 regarding the income tax allowance, as well as to other elements of the FERC's rate methods for petroleum pipelines. SFPP is now a subsidiary of a publicly traded limited partnership engaged in the transportation of petroleum products. In the first proceeding, the FERC issued Opinion No. 435 in which the FERC, among other things, affirmed Opinion No. 397's determination that there should not be a corporate income tax allowance built into a petroleum pipeline's rates for income attributable to noncorporate partners. Several parties sought rehearing of various issues addressed in Opinion 435, including its decision on the income tax allowance issue. The FERC addressed the requests for rehearing in Opinion No. 435-A, issued on May 17, 2000, in Opinion No. 435-B, issued on September 13, 2001, and in two subsequent orders. Several parties to the case have filed for judicial review before the D.C. Circuit of one or more of the FERC's decisions in this proceeding. While the ultimate outcome of the income tax allowance issue and other questions that are considered on review could reduce the maximum amount we could legally charge under our FERC regulated tariffs, we do not believe that any such ruling would have a material impact on our results of operations.

The second proceeding involving SFPP, involves, among other issues, shippers' challenges to SFPP rates that were grandfathered under the Energy Policy Act. A hearing before a FERC administrative law judge concerning this proceeding commenced in October 2001. An initial decision by the administrative law judge was issued on one phase of the proceeding in June of 2003. Briefs on and opposing exceptions to that decision were subsequently filed at the FERC, where the case is now pending. We cannot predict at this time what effect this proceeding will have on the ability of parties to challenge grandfathered rates.

Our Pipelines. The FERC generally has not investigated interstate rates on its own initiative when those rates have not been the subject of a protest or a complaint by a shipper. A shipper or other party having a substantial economic interest in our rates could, however, challenge our rates. In response to such challenges, the FERC could investigate our rates. To the extent that a complainant challenged an interstate rate that is grandfathered under the Energy Policy Act, the complainant would have to first demonstrate a substantial change since the date of enactment of the Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. A complainant could assert that the creation of Pacific Energy Partners, L.P. itself constitutes such a change, an argument that has been raised in the second SFPP proceeding discussed above, but which has not been specifically addressed by the FERC. If the FERC were to find a substantial change in circumstances, then the grandfathered rates could be subject to detailed review. Upon review of grandfathered rates for which a substantial change has been shown and any non-grandfathered rates, the FERC could inquire into all costs that underlie the rates being charged, including operating expenses, the allocation of overhead costs, capital structure and rate of return and allowance for federal and state income taxes. If our rates were successfully challenged, the amount of cash available for distribution to unitholders could be materially reduced.

Intrastate Pipelines

California. The CPUC regulates the tariffs we charge shippers on Line 2000 and the Line 63 system. Line 2000 has market-based tariffs and the Line 63 system has cost-of-service based tariffs.

Cost-of-service based rates are calculated by determining our revenue requirement, which is based on the sum of (1) forecasted costs of operating and maintaining the pipeline and associated administrative and general costs during a test year period, (2) depreciation, (3) a return (*i.e.*, the authorized rate of return) on the depreciated, historical capital investment and capital additions in the pipeline facilities, and (4) the associated taxes. To establish a unit transportation rate, the revenue requirement is allocated across the test year's forecasted throughput. Generally, to change rates, the pipeline must show that there will be a change in its costs of operation or that its rate base (*i.e.*, its capital investment) has or will change during the test year or that the cost of capital associated with its return on investment has changed, either because of a change in risk or in the cost of capital in general, or that there will be a change in throughput. To change rates, the pipeline must file a rate application that is subject to review by the CPUC. A rate filing may be protested and set for hearing. Once the CPUC reviews the application and determines a revenue requirement, the revenue requirement is converted into a rate per barrel of forecasted throughput.

Market-based rates, on the other hand, are not dependent on the pipeline's operating costs or investment, or forecasted throughput. Rather, within certain limits, the pipeline is free to file for negotiated rates or rates based on its perception of what the market will bear. To qualify for market-based rates, the pipeline has to demonstrate to the CPUC that there is competition in the market it serves and that it does not have market power. The CPUC may put certain limits on the number of rate changes that can be made during the course of a year or on the percentage increase in rates that can occur in any one year. A pipeline with market-based rates must still make a filing with the CPUC to modify its rates, but this is usually done through an advice filing. The advice filing can be protested and set for hearing, but the grounds for protest should be more limited than for cost-of-service based rate filings since the CPUC has previously granted market-based rate authority to the pipeline. A market-based pipeline, such as Line 2000, does not have an approved rate base, an authorized rate of return on its investment or an approved operation and maintenance or administrative and general cost calculation. A market-based pipeline assumes the risk of changes in its throughput.

Under either cost-of-service based or market-based ratemaking, the pipeline must give the CPUC and its shippers at least 30-days notice of the proposed change in rates. For pipelines that are regulated on a cost of service basis, such as the Line 63 system, this notice may require the filing of a formal rate application. For pipelines with market-based rate authority, such as Line 2000, this notice frequently is in the form of an advice filing. So long as an increase in rates does not exceed 10% in any 12-month period, upon expiration of the 30-day notice period the pipeline is permitted to change rates and to use those rates prior to CPUC approval, unless the CPUC suspends the rate change and its use. By law, the CPUC is allowed to suspend a proposed change in rates for an additional 30-day period following the expiration of the 30-day notice period. After that, the pipeline is allowed to put the proposed rates into effect, but must refund with interest any portion of a rate change that is subsequently disallowed by the CPUC. A pipeline with either cost-of-service based or market-based rates may file for a rate increase that exceeds 10% per 12-month period, but it is not allowed to put the rates into effect prior to the CPUC approving the change.

The CPUC, on its own initiative or at the urging of a shipper or interested party, may commence its own proceeding to change or reduce rates or alter the terms and conditions of service. In addition, the legislature or the CPUC may modify ratemaking methodologies with resulting tariffs that generate lower revenue and cash flow.

In Decision 94-10-044, which authorized SCE to utilize its fuel oil pipeline facilities for services to third parties, the CPUC authorized SCE to negotiate and execute individual contracts with customers for storage, pipeline distribution and other utility services. In Decision 03-07-031, which authorized the sale of the EPTC assets to PT, the CPUC authorized us to continue the same methodology for establishing storage and transportation fees that it had authorized for SCE.

Montana. The portion of the Western Corridor system located in Montana is exclusively an interstate pipeline system, transporting Canadian crude oil. As such, it is not subject to the jurisdiction of the Montana Public Service Commission.

Wyoming. The WPSC regulates the tariffs and crude oil transportation rates charged for intrastate deliveries on Big Horn pipeline of the Western Corridor system and the Salt Lake City Core system. These tariffs are primarily cost-of-service based, but free-market and competitive factors can influence the tariffs as well.

Cost-of-service based rates are calculated by determining the sum of (1) the forecasted cost of operating and maintaining the pipeline and associated administrative and general costs, (2) a return on the capital investment in the pipeline facilities (*i.e.*, authorized rate of return) and (3) a recovery of such capital investment (*i.e.*, depreciation).

Colorado. We operate the portion of the Salt Lake City Core system located in Colorado as a common carrier interstate pipeline system, transporting third-party shippers' crude oil to Salt Lake City, making no deliveries in Colorado. As such, the Salt Lake City Core system is not subject to the jurisdiction of the Colorado Public Utilities Commission.

Utah. The Salt Lake City Core system does make intrastate crude oil deliveries. However, Utah law does not regulate intrastate oil pipeline operations or their tariff rates as public utilities.

The adoption by us of a cost-of-service based tariff under federal or state law does not guarantee that we will recover all of our costs relating to a pipeline system or segment.

Environmental Regulation

General

Our operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling and release of crude oil and other liquid hydrocarbon materials. Furthermore, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent change at the federal, state and local levels, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Therefore, we are unable to predict the ongoing cost of complying with these laws and regulations or their future impact on our operations.

There are also risks of accidental releases into the environment associated with our operations, such as leaks or spills of crude oil or hazardous substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for any related violations of environmental laws or regulations.

Although we are entitled in certain circumstances to indemnification from third parties for environmental liabilities relating to assets that we acquired from those parties, these contractual indemnification rights are limited and, accordingly, we may be required to bear substantial environmental expenses.

Air Emissions

Our operations are subject to the Federal Clean Air Act and comparable state and local statutes. Amendments to the Clean Air Act enacted in 1990, as well as recent or soon to be adopted changes to state implementation plans implementing those amendments, require or will require most industrial operations in the United States to make capital expenditures in order to meet air emission control standards developed by the U.S. Environmental Protection Agency ("EPA"), and state environmental agencies. As a result of these amendments, our facilities are subject to increasingly stringent air emissions regulations, including requirements that some facilities install maximum or best available control technologies to reduce or eliminate regulated emissions. We anticipate, therefore, that we will incur certain capital expenses in the next several years for air pollution control equipment in connection with maintaining existing facilities and obtaining permits and approvals for new or acquired facilities. Although we can give no assurances, we believe implementation of these Clean Air Act requirements will not have a material adverse effect on our financial condition or results of operations.

We are subject to various state air emission regulations that can be more stringent than federal regulations under the Clean Air Act. For example, our California operations are subject to the California Clean Air Act ("CCAA"). Under the CCAA, the California Air Resources Board has established state ambient air quality standards and toxic air contaminants requirements that are sometimes more restrictive and broader in scope than federal requirements. The local air quality regulations also tend to be more stringent than the federal regulatory requirements in areas where air quality standards have not been achieved, such as the San Joaquin Valley and the Los Angeles area. All of our facilities have active permits to operate from the local air districts. These permits set forth specific conditions that may limit the throughput or the types of material that may be transported or stored.

Hazardous Substances and Waste Management

The Federal Comprehensive Environmental Response, Compensation and Liability Act, ("CERCLA") (also known as the "Superfund" law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of sites where hazardous substances have been released into the environment and companies that disposed or arranged for disposal of hazardous substances found at such sites. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment at such disposal sites and to seek recovery of the costs they incur from the responsible classes of persons. Although "petroleum" is currently excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we may handle some materials that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such materials have been released into the environment. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or similar state laws.

Our operations also generate both hazardous and nonhazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes. We are not currently required to comply with a substantial portion of RCRA's requirements as our operations generate minimal quantities of hazardous wastes. From time to time, however, the EPA has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for these wastes, including certain crude oil wastes. Furthermore, it is possible that some of the wastes we generate that are currently classified as nonhazardous may in the future be reclassified as "hazardous wastes," which would trigger more rigorous and costly disposal requirements. Any such regulatory changes could result in an increase in our maintenance capital expenditures and operating expenses. In addition, analogous state and local laws may impose more stringent waste disposal requirements or a apply to a broader range of wastes.

Water

The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws place strict limits on the discharge of contaminants into federal and state waters. Regulations under these laws prohibit such discharges unless authorized by and in compliance with a National Pollutant Discharge Elimination System ("NPDES"), permit or an equivalent state permit. The Clean Water Act and analogous state laws allow significant penalty assessments for unauthorized releases of water pollutants and impose substantial liability for the costs of cleaning up spills and leaks into the water. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of stormwater runoff from certain types of facilities. State laws may also place restrictions and cleanup requirements on the release of pollutants into groundwater. We believe that we will be able to obtain, or be covered under, any required Clean Water Act permits and that compliance with the conditions of those permits will not have a material effect on our operations.

The Oil Pollution Act ("OPA"), was enacted in 1990 and amends parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. Some states, including California, have also enacted similar laws. We believe we are in material compliance with these laws.

Endangered Species Act

The Federal Endangered Species Act, as well as similar state laws, restrict activities that may affect threatened or endangered animal or plant species or their habitats. Some of our California facilities are located in, or pass through, areas that include or are designated as critical habitat for certain endangered species. Therefore, the Fish and Wildlife Service of the U.S. Department of the Interior has issued a Biological Opinion for Ongoing Maintenance Activities, which contains specific covenants related to our crude oil pipelines in these critical habitat areas. We believe that we are in compliance with the covenants of this opinion regarding the Endangered Species Act.

Site Remediation

We own or lease a number of pipelines, gathering systems and storage facilities that have been used to store or distribute crude oil for many years, most of which were previously owned and operated by third parties whose handling, disposal or release of crude oil and wastes were not under our control. While our past operating and waste disposal practices were standard for our industry at the time, historical spills and releases along or at our properties by us and by previous owners and operators of our assets have resulted in soil contamination and may have resulted in groundwater contamination in some locations. Such contamination caused by historical activities is not unusual within the petroleum pipeline industry. We have conducted site investigations at a number of these properties to assess environmental issues, including soil and groundwater conditions. Any historical contamination found on, under or originating from our properties may be subject to CERCLA, RCRA and analogous state laws as described above. Under these laws, we could incur substantial expense to remediate any such contamination, including contamination caused by prior owners or operators. We currently do not have any active regulatory mandated or voluntary assessment, monitoring or remediation programs at company owned facilities. In connection with our acquisitions, we have assumed the following liabilities representing the estimated cost of remediating the properties acquired, (1) in connection with the acquisition of ARCO Pipe Line Company ("ARCO")'s ownership interest in PPS in 2001, we assumed a $2.6 million liability representing the estimated cost of remediating the properties that had been contributed to PPS by ARCO in 1999, (2) in connection with the acquisition of the PMT assets in 2001, we assumed a $0.1 million liability for estimated remediation costs pursuant to a final agreement entered into on September 2, 2003, and (3) in connection with the acquisition of the storage and pipeline distribution assets from EPTC on July 31, 2003, we assumed a $2.7 million liability for estimated environmental remediation costs. However, there is no guarantee that the actual remediation costs or associated liabilities will not exceed these amounts. Please also read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Recent Accounting Pronouncements" below.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. We have not received legal opinions or title insurance with respect to any of our rights-of-way. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the right-of-way grants. We have permits, leases, license agreements and franchise ordinances from public authorities to cross over or under or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, these permits are revocable at the election of the grantor. We also have license agreements from railroad companies to cross over or under railroad properties or rights-of-way some of which are also revocable at the grantor's election. In some cases, property on which our pipeline was built is held under long-term leases or owned in fee.

In some instances the above rights-of-way are revocable at the election of the landowner. We potentially have, subject to various limitations in each state in which our pipelines are located, rights to condemn private property used in connection with our common carrier pipelines, therefore mitigating some adverse impact of any existing revocation rights. For example, in California, public utility pipeline companies may condemn private property subject to certain limitations and procedures, provided, that if such condemnation is for the purpose of competing with any entity offering the same competitive services, such company must obtain CPUC approval. In Montana, condemnation rights are available to common carrier crude oil pipeline companies that file appropriate documentation with the Montana Public Service Commission, which filing could subject such companies to additional regulation. In Colorado, a corporation (and possibly other forms of entities) formed for the purpose of constructing a pipeline may acquire a right of way by condemnation, provided that the corporation conforms to statutory condemnation procedures. In Utah and Wyoming, condemnation rights are available on behalf of the public use of crude oil pipelines, subject to certain limitations. Under Utah and Wyoming law, public or private entities may acquire easements by eminent domain for crude oil pipelines in accordance with specified statutory procedures.

All pump station properties for our common carrier pipelines are either on land that we own in fee, on property under a long-term lease or, in several cases, held under a Special Use Permit from the United States Department of the Interior. Our headquarters and control center are located on a 27.50-acre property in Long Beach that we own in fee. Crude oil storage tanks, maintenance facilities and warehouse space are also located on this property. Our Bakersfield office and maintenance facility is located in a 15,000 square foot combination office space/warehouse building, occupied pursuant to a long-term lease. To support our Rocky Mountain operations, we have crude oil storage tanks and maintenance and warehouse facilities on land we own in fee in Casper, Wyoming. Our Evanston, Wyoming office and maintenance facility is occupied pursuant to a long-term lease.

We believe we have satisfactory title or other right to all of our material assets. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, and minor easements, restrictions, and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us. However, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties or will materially interfere with their use in the operation of our business.

Employees and Labor Relations

We do not have any employees. Our General Partner employs approximately 260 employees who directly support our operations. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us. None of our General Partner's employees are subject to a collective bargaining agreement. Our General Partner considers its employee relations to be good.

Risks Inherent in Our Business

We may not have sufficient cash from operations to pay the minimum quarterly distribution following establishment of cash reserves and after payment of fees and expenses, including payments to our General Partner.

We may not have sufficient available cash each quarter to pay the minimum quarterly distribution on all units. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the volume of crude oil we transport through our pipelines;
- the tariff rates we charge on our pipelines;
- the percentage of storage capacity we have under lease;
- the lease rates we charge on our storage tanks;
- margins in our buying, gathering, blending and selling operations;
- the level of our operating costs, including payments to our General Partner;
- the level of competition from other pipelines; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, such as:

- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any;
- our ability to borrow under our working capital facility to make distributions; and
- the amount, if any, of cash reserves established by our General Partner, in its discretion.

The amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may not make cash distributions during periods when we record net income.

A material decline in the volume of crude oil processed by any of the refineries we serve could reduce our ability to make distributions to our unitholders.

Any significant reduction in the volume of crude oil processed at the refineries we serve could reduce the volume of crude oil we transport on our pipelines, or throughput, and result in our realizing materially lower levels of revenue and cash flow. This reduction could occur for a number of reasons, including:

- A sustained decrease in demand for refined products, which could result from:
  - a local or national recession or other adverse economic condition that results in lower spending by businesses and consumers on gasoline, diesel fuel and jet fuel;
  - an increase in the market price of crude oil that leads to higher refined product prices, resulting in lower demand;
  - higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products; or
  - a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or alternative fuel sources, or otherwise.
- Refineries we serve could partially or completely shut down their operations, temporarily or permanently, due to factors affecting their ability to produce refined products such as:
  - unscheduled maintenance or catastrophic events at a refinery, such as a fire, flood, explosion or power outage;
  - labor difficulties that result in a work stoppage or slowdown at a refinery;
  - environmental litigation or other proceedings that require the halting of all or a portion of the operations at a refinery;
  - increasingly stringent environmental regulations, such as the Environmental Protection Agency's gasoline and diesel sulfur control requirements that limit the concentration of sulfur in motor gasoline and diesel fuel;
  - a governmental ban or other limitation on the use of any important feedstock or product of a refinery; or
  - other legislation or regulation that adversely impacts the economics of refinery operations.
- The refineries we serve may be unsuccessful in competing against other existing or future sources of refined products in their markets, such as pipelines or marine barges or tankers that deliver refined products into the Los Angeles Basin or the Rocky Mountain region from refineries in other areas.

A material decrease in the production of crude oil from the oil fields served by our pipelines could materially reduce our ability to make distributions to our unitholders.

The throughput on our pipelines depends on the availability of attractively priced crude oil produced from the oil fields served by our pipelines, or through connections with pipelines owned by third parties. Crude oil production may decline for a number of reasons, including natural declines due to depleting wells, a material decrease in the price of crude oil or the inability of producers to obtain necessary drilling or other permits from applicable governmental authorities. If we do not replace volumes lost due to a temporary or permanent material decrease in production from the oil fields served by our pipelines, our throughput would decline, reducing our revenue and cash flow and adversely affecting our ability to make cash distributions to our unitholders.

Certain of the crude oil producing fields served by our pipelines are experiencing a decline in production. In addition, declining production may impact us in the future if shippers elect to replace ANS crude oil in San Francisco with crude oil produced in the San Joaquin Valley and California Outer Continental Shelf.

A decrease in the price of crude oil, on either a temporary or permanent basis, may also affect the total volume of crude oil produced from the fields served by our pipelines. If crude oil prices were to decline significantly, as they did in 1998 and other periods in the past, production from certain of the fields served by our pipelines may cease to be profitable and crude oil producers may decide to decrease or stop production. In addition, an increase in the price of natural gas or electricity, both of which are used in connection with an advanced recovery technique known as steam-flooding, could result in a decrease in steam-flood operations in certain of the fields served by our pipelines and therefore reduce production.

To maintain our throughput, new supplies of crude oil must be available to offset volumes lost because of declines in crude oil production. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is declining and competition to gather available production is intense. It is difficult to attract producers to a new gathering system if the producer is already connected to an existing system. As a result, we or third-party shippers on our pipeline systems may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil.

If the refineries we serve process crude oil from locations to which our pipelines do not directly or indirectly connect, throughput on our pipelines could materially decline.

Throughput on our West Coast pipelines serving the Los Angeles Basin decreases to the extent refineries in the Los Angeles Basin choose to process more ANS and foreign crude oil and less California crude oil. Refineries in the Los Angeles Basin currently process crude oil produced in California, Alaska and various foreign nations. Marine barges and tankers deliver ANS and foreign crude oil to the Ports of Los Angeles and Long Beach. This crude oil is then directed through third-party pipelines to the various refineries and terminal facilities serving the Los Angeles Basin. These waterborne deliveries compete with crude oil produced in the San Joaquin Valley and California Outer Continental Shelf that is transported to the Los Angeles Basin on Line 2000 and the Line 63 system. This decreases our West Coast operations' revenue and cash flow and could impair our ability to make distributions.

The refineries we serve may not be able to secure adequate supplies of crude oil from the crude oil producing areas served by our pipelines. For example, the refineries in the Los Angeles Basin that are served by our Line 2000 and Line 63 pipelines compete with refineries in the San Francisco Bay and central California areas for supplies of crude oil produced in the San Joaquin Valley and California Outer Continental Shelf; and to the extent this crude oil is directed to the San Francisco refiners, a decision over which we have no control, our throughput volumes and revenue would be adversely affected.

Shell Oil Company recently announced that it would close its Bakersfield, California refinery by October 1, 2004, an event that we have projected will result in a net increase in volume on our pipelines. There is no assurance that Shell's Bakersfield refinery will in fact be shut down or if there is such a shut down, when it will occur. Certain elected officials in California have recently expressed concern about the proposed shutdown and have stated that Shell should be required to try to find a buyer for the refinery that would keep it operating.

New competing pipeline systems could also be built or existing pipeline systems expanded that could deliver crude oil from other locations to the refineries that we serve. This could cause us to reduce our tariff rates or to experience reduced throughput.

Due to our lack of asset diversification, adverse developments in our transportation and storage businesses could reduce our ability to make distributions to our unitholders.

We rely primarily on the revenue generated from our transportation and storage businesses. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we operated more diverse assets.

Tariff rate regulation or a successful challenge to our tariff rates may reduce the tariff rates we charge and the amount of cash available for distribution to our unitholders.

Interstate Pipelines. The FERC regulates the tariff rates for our interstate common carrier operations. Shippers may protest our tariffs, and the FERC may investigate the lawfulness of new or changed tariff rates. The FERC may also investigate tariff rates that have become final and effective and require refunds of amounts collected under tariff rates ultimately found unlawful. The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of tariff rates that reflect increased costs.

In recent decisions involving unrelated oil pipeline limited partnerships, the FERC has ruled that these partnerships may not claim an income tax allowance for income allocable to non-corporate limited partners. A shipper could rely on these decisions and claim that, because of the creation of the partnership, the income tax allowance used to calculate our interstate tariff rates should be reduced. If the FERC were to disallow the inclusion of all or part of the income tax allowance, it may be more difficult to justify some of our tariff rates. Any reduction in our tariff rates would most likely result in lower revenue and cash flows and may reduce our ability to make cash distributions to our unitholders.

Intrastate Pipelines and Terminals. The majority of our intrastate pipeline and terminal operations are subject to regulation by state public utility commissions. A state commission may investigate our intrastate tariff rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our tariff rates were not justified, the state commission could order us to reduce our tariff rates. If a state commission were to withdraw or modify our authority or use certain non-cost based rates, such as market based rates or the authority to negotiate or enter into individual customer contracts, which we have for a significant portion of our facilities, our revenue and cash flows may be adversely affected, which could adversely affect our ability to make distributions to our unitholders.

We may be unsuccessful in competing against existing or future pipelines in the areas in which we currently operate or may operate in the future.

Our principal competitors for large volume shipments of crude oil are other pipelines. For example, we compete with Express pipeline in transporting Canadian crude oil to the Rocky Mountain region. New crude oil pipelines could also be constructed in the areas served by our pipelines. Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and customer demand for crude oil. We compete to a lesser extent with trucks that deliver crude oil in several areas in which we serve. Some of our competitors have greater financial and other resources than we have. If we are unsuccessful in competing against other pipelines or trucking operations, throughput in our pipelines could be reduced and we may be unable to make cash distributions to our unitholders. Please read "Items 1 and 2 Business and Properties West Coast Operations Competition" and " Rocky Mountain Operations Competition" for a further discussion of the competition we face.

We are exposed to the credit risk of our customers in the ordinary course of our business.

In our buying, gathering, blending and selling business, when we purchase crude oil at the wellhead, we sometimes pay all or a portion of the production proceeds to an operator, who distributes those proceeds to the various interest owners. This arrangement may expose us to operator credit risk, and we must determine whether the operators have sufficient financial resources to make these payments and distributions and to indemnify and defend us in case of a protest, action or complaint. Even if our credit review and analysis mechanisms work properly, we may experience losses in dealings with operators and other parties.

Our operations are subject to federal, state and local laws and regulations, including those relating to environmental protection, operations and safety, that could require us to make substantial expenditures.

Our operations are subject to federal, state and local laws and regulations relating to environmental protection, operations and safety. Many of these laws and regulations impose increasingly stringent permitting and operating requirements. In addition, these laws and regulations are subject to change, which change could result in an increase in our ongoing cost of compliance and have an adverse effect on our operations. We could, therefore, be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from compliance with future required operating permits. Failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties and, in some instances, the issuance of injunctions to limit or cease operations. In addition, there are risks of accidental releases associated with our operations, such as leaks or spills of crude oil from our pipelines or storage facilities, which could result in significant liabilities arising from environmental cleanup and restoration costs and claims for personal injury and property damage. If we were unable to recover such costs through insurance or increased tariff rates, cash distributions to our unitholders could be adversely affected.

We also own or lease a number of properties that have been used to store or distribute crude oil for many years. Crude oil and wastes associated with these historical activities may have been disposed of or released into the environment at these properties or at other locations where such materials may have been taken for disposal. In addition, most of these properties have been operated by third parties whose handling, disposal and release of crude oil and waste materials were not under our control. We could incur significant liabilities for cleanup and restoration costs and claims for personal injury and property damage related to these historical activities. Please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our operations are also subject to extensive operations and safety regulation. Many departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations binding on the crude oil industry and its individual participants. The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the crude oil industry increases our cost of doing business and, consequently, affects our profitability. Please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

Our operations are subject to operational hazards and unforeseen interruptions, such as natural disasters, accidents, fires, explosions, hazardous materials releases, acts of terrorism or other events beyond our control. A casualty might result in personal injury or loss of life, loss of equipment or loss of or extensive damage to property, as well as an interruption in our operations or the operations of the refineries to which we deliver. A significant portion of our assets are located in California, which has a high incidence of earthquakes. In addition, we may not be able to maintain our existing insurance coverage or obtain new coverage of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts.

We have not generally purchased business interruption insurance and our insurance does not cover acts of terrorism. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position.

Any reduction in the capability of, or the allocations to our shippers on, connecting, third-party pipelines could cause a reduction of throughput on our pipelines and could reduce the amount of cash available for distribution to our unitholders.

We depend upon connections to third-party pipelines to deliver crude oil to some of our customers. Any reduction of capabilities in these connecting pipelines due to testing, line repair, reduced operating pressures, a decline in production associated with the third-party system or other causes could result in reduced throughput on pipelines. Similarly, any reduction in the allocations to our shippers on these connecting pipelines because additional shippers begin transporting volumes over the pipelines could also result in reduced throughput on our pipelines. Any reduction in throughput on our pipelines could adversely affect our revenue and cash flow and our ability to make distributions to our unitholders.

We are dependent on a small number of customers for a substantial portion of our revenue.

In 2003, the following customers represented greater than 10% of net revenue for our West Coast operations: ChevronTexaco; ExxonMobil Refining and Supply Company; Shell Trading Company and Valero Marketing and Supply Company. In addition, the following customers represented greater than 10% of net revenue for our Rocky Mountain operations: ChevronTexaco and Tesoro. The loss of any of these customers, a decline in their credit worthiness or a substantial reduction in their shipments on our pipelines, could adversely affect our results of operations and cash flows and our ability to make distributions to our unitholders.

We are dependent on use of a third-party marine dock for delivery of waterborne products into our storage and distribution facilities.

A portion of our storage and distribution business conducted in the Los Angeles area is dependent on our ability to receive waterborne crude oil and other dark products, which are presently being received through dock facilities operated by Shell Oil Products US in the Port of Long Beach. The agreement that allows us to utilize these dock facilities expires in October 2005, and there is no guarantee that it will be renewed. If this agreement is not renewed and if other alternative dock access cannot be arranged, the volumes of crude oil and other dark products that we presently receive from our customers may be reduced, which could result in a reduction of storage and distribution revenue and cash flow, which could adversely affect our ability to make distributions to our unitholders.

Our ability to execute our acquisition or project development strategy may be impaired if we are unable to complete accretive acquisitions or projects on acceptable terms or access new capital.

Our ability to grow will depend principally on our ability to complete accretive acquisitions and development projects. We may be unable to identify attractive acquisition or project candidates or to complete acquisitions or projects on economically acceptable terms. Acquisition transactions can occur quickly and at any time and may be significant in size relative to the size of our existing asset base. We may need new capital to finance these acquisitions and development projects, and limitations on our ability to access new sources of capital may impair our ability to make acquisitions or undertake projects. If we are able to access new sources of capital, but only at more expensive rates, our ability to make accretive acquisitions or undertake projects will be limited. Our ability to maintain our capital structure may impact the market value of our common units.

The completion and successful operation of our Pier 400 Project remains subject to a number of unique risks, including: (1) an exhaustive permitting process that, even if successful, could result in the imposition of requirements and conditions that could adversely affect the feasibility and economic returns we expect from the project, (2) political and legal opposition from interest groups and constituencies that have interests in the Port of Los Angeles and the project that differ from our position, (3) our ability to obtain the financing necessary to construct the project, which may depend on our ability to obtain other long-term commitments from creditworthy customers, which cannot be assured, and

(4) the need to reach an agreement with Valero on a number of key issues related to our operation of the Pier 400 facilities on Valero's behalf, including such issues as Valero's Marketing and Supply Company volume and environmental cost commitments.

Our pending acquisition of the Rangeland Pipeline System from BP Canada Energy Company is subject to regulatory approvals and other conditions over which we have limited control.

Our obligation to consummate the pending Rangeland acquisition is not subject to a financing condition. If we are unable to obtain the capital necessary to consummate the acquisition, we may be required to forfeit our $13 million (Canadian) earnest money deposit.

Our debt levels or restrictions in our debt agreements may prevent us from engaging in some beneficial transactions or paying distributions if we are in default.

At December 31, 2003, our total outstanding long-term indebtedness was $298.0 million. Our payment of principal and interest on this indebtedness will reduce the cash available for distribution on our units. We are prohibited by our credit agreement from making cash distributions during an event of default or if the payment of a distribution would cause an event of default. Various limitations in our credit agreement may reduce our ability to incur additional debt or to engage in some transactions and therefore to make acquisitions or pursue other business opportunities. Any subsequent refinancing of our current debt or any new debt could have similar or greater restrictions.

Risks Inherent in an Investment in Us

Cost reimbursements to our General Partner, which are determined in our General Partner's sole discretion, may be substantial and reduce our cash available for distribution to you.

Our General Partner is entitled to be reimbursed for all expenses it incurs on our behalf and has sole discretion in determining the amount of these reimbursements. Our obligation to reimburse our General Partner for expenses may be substantial. These cost reimbursements to our General Partner reduce the amount of available cash for distribution to our unitholders. Our General Partner and its affiliates also may provide us other services for which we will be charged fees as determined by our General Partner.

Our General Partner's discretion in establishing cash reserves may reduce the amount of cash available for distribution to you.

Our partnership agreement requires our General Partner to deduct from operating surplus cash reserves that, in its reasonable discretion, are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to you.

Anschutz and its affiliates have conflicts of interest with, and limited fiduciary responsibilities to, our unitholders, which may permit them to favor their own interests to your detriment.

As of December 31, 2003, Anschutz and its affiliates owned an aggregate 43.2% interest in us, consisting of the 2% general partner interest and a 41.2% limited partner interest, and Anschutz owns and controls our General Partner. Conflicts of interest may arise between Anschutz and its affiliates, including our General Partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Anschutz to pursue a business strategy that favors us or utilizes our assets. The directors and officers of Anschutz have a fiduciary duty to make decisions in the best interests of the stockholder of Anschutz;

- Anschutz and its affiliates may engage in limited competition with us;

- our General Partner is allowed to take into account the interests of parties other than us, such as Anschutz, in resolving conflicts of interest;

- under Delaware law, our General Partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash, if any, that is distributed to our unitholders;

- our General Partner determines which costs incurred by it and its affiliates are reimbursable by us;

- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates; and

- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our General Partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates that reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its "sole discretion." This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our General Partner is entitled to make other decisions in its "reasonable discretion";

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the interests of all parties involved, including its own; and

- provides that our General Partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Even if unitholders are dissatisfied, they cannot easily remove our General Partner, which could lower the trading price of the common units.

Our General Partner manages and operates us. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our General Partner or its board of directors and have no right to elect our General Partner or its board of directors on an annual or other continuing basis.

The board of directors of our General Partner is chosen by Anschutz. The directors of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to Anschutz, the ultimate owner of our General Partner.

Furthermore, if unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. Our General Partner generally may not be removed except upon the vote of the holders of at least $66^2/_3$% of the outstanding units voting together as a single class. Because Anschutz controls approximately 42.0% of all the units representing limited partner interests, our General Partner currently cannot be removed without its consent. Also, if our General Partner is removed without cause during the subordination period and units held by our General Partner and its affiliates, including Anschutz, are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of the General Partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which preferences would otherwise have continued until we had met certain distribution and performance tests.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our General Partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our General Partner. Cause does not include most cases of charges of poor management of the business, so the removal of our General Partner because of our unitholders' dissatisfaction with our General Partner's performance in managing our partnership will most likely result in the early termination of the subordination period.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision which states that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

The control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on Anschutz's ability, as the ultimate owner of our General Partner, to transfer its ownership interest in our General Partner to a third party. The new owner of the general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions made and actions taken by the board of directors and officers.

We may issue additional units without your approval, which would dilute your ownership interests.

During the subordination period, our General Partner may cause us to issue up to 5,232,500 additional common units without unitholder approval. Our General Partner may also cause us to issue an unlimited number of additional common units or other partnership securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in connection with acquisitions or capital improvements that our General Partner determines would increase the amount of cash flow from operations per unit on a pro forma or estimated pro forma basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances;
- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal of our General Partner;
- issuances of common units pursuant to employee benefit plans; or
- issuances of common units to repay certain indebtedness.

Upon the expiration of the subordination period, we may issue an unlimited number of common units or other partnership securities without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of partnership securities ranking junior to the common units at any time.

The issuance of additional common units or other partnership securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our General Partner may cause us to borrow funds in order to make cash distributions, even if the purpose or effect of the borrowing benefits the general partner or its affiliates.

In some instances, our General Partner may cause us to borrow funds from affiliates of Anschutz or from third parties to make cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make a distribution on the subordinated units, to make incentive distributions or to hasten the expiration of the subordination period.

Our General Partner has a limited right to buy out minority unitholders if it owns more than 80% of the common units, which may require you to sell your common units against your will and at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, but not the obligation, to acquire all, but not less than all, of the remaining common units held by unaffiliated unitholders. As a result, you may be required to sell your common units against your will and at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units.

If our General Partner exercises its buy out right, the common units will be purchased at the greater of:

- the most recent 20-day average trading price ending on the date three days prior to the date the notice of purchase is mailed; or
- the highest price paid by our General Partner or its affiliates to acquire common units during the prior 90 days.

Our General Partner can assign its limited call right to an affiliate or to us.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Assignees who become substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the assignee at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks

The IRS could treat us as a corporation for tax purposes, which would substantially reduce any cash available for distribution to our unitholders.

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gain, loss, or deduction would flow through to our unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore would likely result in a substantial reduction in the value of our common units. Moreover, treating us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution would be reduced. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amount will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will reduce cash available for distribution to our unitholders and our General Partner.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may disagree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and our General Partner and thus will be borne indirectly by our unitholders and our General Partner.

Unitholders may be required to pay taxes on their share of our income from us even if they do not receive any cash distributions from us.

Unitholders will be required to pay any federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from the taxation of their share of our taxable income.

Tax gain or loss on disposition of our common units could be different than expected.

A unitholder who sells common units will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income allocated to that unitholder, which decreased the tax basis in that unitholder's common unit, will, in effect, become taxable income to that unitholder if the common unit is sold at a price greater than that unitholder's tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to that unitholder.

Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Very little of our income will be qualifying income to a regulated investment company. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to individuals, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We have registered as a tax shelter. This may increase the risk of an IRS audit of us or our unitholders.

We are registered as a tax shelter with the Secretary of the Treasury. Our tax shelter registration number is 02212000004. The IRS requires that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments to, and may lead to audits of, the tax returns of individual unitholders, including adjustments unrelated to us. You will bear the cost of any expense incurred in connection with the examination of your personal tax returns.

Recently issued Treasury Regulations require taxpayers to report certain information on Internal Revenue Service Form 8886 if they participate in a "reportable transaction." Unitholders may be required to file this form with the IRS if we participate in a "reportable transaction." A transaction may be a reportable transaction based upon any of several factors. Unitholders are urged to consult with their own tax advisor concerning the application of any of these factors to their investment in our common units. Congress is considering legislative proposals that, if enacted, would impose significant penalties for failure to comply with these disclosure requirements. The Treasury Regulations also impose obligation on "material advisors" that organize, manage or sell interests in registered "tax shelters." As stated above, we have registered as a tax shelter, and, as a result, one of our material advisors will be required to maintain a list with specific information, including unitholder names and tax identification numbers, and to furnish this information to the IRS upon request. Unitholders are urged to consult with their own tax advisor concerning any possible disclosure obligation with respect to their investment and should be aware that we and our material advisors intend to comply with the list and disclosure requirements.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in California, Montana, Wyoming, Colorado and Utah. Of these states, only Wyoming does not currently impose a personal income tax. It is the responsibility of each unitholder to file all United States federal, foreign, state and local tax returns that may be required of such unitholder.

ITEM 3. Legal Proceedings

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the WPSC alleging that RMPS's common stream rules and specifications and RMPS's refusal to prohibit certain types of crude oil diluents from the sour crude oil common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. A hearing on Sinclair's complaint was held by the

WPSC in October 2002, and on October 21, 2003, the WPSC issued its written order, directing RMPS to adopt tariff language prohibiting the blending of certain types of crude oil containing diluents with the Wyoming sour crude oil common stream on the Big Horn segment. The effect of this decision, if it stands, is that RMPS would not be allowed to continue its practice of commingling Bow River crude oil, a Canadian crude oil that contains diluent, with the Wyoming crude oil that Sinclair claims is being harmed by the presence of such diluent. As a consequence, RMPS would be required to transport the Wyoming sour crude oil common stream in segregated batches separate from the Bow River crude oil stream containing diluent. We have petitioned the WPSC for a rehearing, seeking clarification of the WPSC's order or, in the alternative, a reversal of the order. The full impact of the WPSC's order cannot be determined in the absence of further clarification from the WPSC, but if the order were to stand as issued, RMPS could be required to incur an estimated $1.7 million of additional capital investment as well as additional operating expense in order to segregate the Wyoming sour crude oils. On March 9, 2004, RMPS entered into a stipulation and agreement with Sinclair, Conoco Pipe Line Company and ConocoPhillips Company that will, if implemented, authorize the inclusion of Bow River crude oil in the Western Corridor common sour stream, as it has been included historically, but with certain Western Corridor gravity bank tariff changes designed to equitably compensate shippers for any associated disadvantage. This stipulation and agreement, which remains subject to various contingences such as shipper, WPSC and FERC approval of the agreed tariff changes, will, if implemented, eliminate the need for RMPS to segregate the Wyoming sour crude oil and will otherwise provide a resolution of Sinclair's complaint at no material cost to RMPS. Regardless of whether the conditions to the implementation of the stipulation and agreement are satisfied, we do not expect this matter to have a material adverse effect on our consolidated financial position or results of operations.

In 2001, Big West Oil Company and Chevron Products Company (the "Complainants") filed complaints against Frontier with the FERC challenging rates contained in joint tariffs in which Frontier was a participating carrier and rates contained in local tariffs filed by Frontier. The joint tariffs challenged by the Complainants were filed by Express Pipeline Partnership on behalf of four connecting carriers: Express, Frontier, AREPI, and Chevron. In January 2002, Frontier reached a partial settlement with the Complainants under which Frontier agreed, among other things, to publish reduced local rates and to pay the Complainants reparations for crude oil transported on Frontier's local rates prior to the January 2002 settlement. The claim for reparations relating to Frontier's portion of the pre-settlement joint tariffs was deferred for later decision by the FERC, with Frontier and the Complainants having stipulated to the rates to be used to calculate such reparations, if any were determined by the FERC to be owing. On February 18, 2004, a decision was issued by the FERC finding Frontier liable for reparations in the aggregate amount of approximately $4.2 million, plus interest which, as of February 29, 2004 would be approximately $1.1 million. Frontier has a right to seek rehearing by the FERC or to appeal the decision directly to the U.S. Court of Appeals. The Partnership does not have control over Frontier's decision whether to appeal, but we believe the FERC's decision is in error and that Frontier will seek a rehearing at the FERC or appeal. We will bear 22.22% of any amount ultimately found to be due. Although we believe Frontier has meritorious issues to assert on a motion for rehearing or appeal, we cannot predict the outcome of any such action; however, based on the initial judgment, Frontier has accrued $5.2 million in 2003 for this contingency. Accordingly, we have recorded a $1.1 million expense for our 22.22% share at December 31, 2003.

We are involved in various other regulatory disputes, litigation and claims arising out of our operations in the normal course of business. However, we are not currently a party to any legal or regulatory proceedings, the resolution of which we could expect to have a material adverse effect on our business, consolidated financial condition or results of operations.

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

There were no matters submitted to a vote of our unitholders during the fourth quarter of 2003.

Part II

ITEM 5. Market Price of and Distributions on the Registrant's Common Equity and Related Unitholder Matters

Our common units are listed on the New York Stock Exchange under the symbol "PPX." At the close of business on December 31, 2003, we had 63 holders of record of our common units, representing approximately 16,000 beneficial owners. The high and low sales price ranges per common unit, as reported on the New York Stock Exchange, and the amount of distributions declared by quarter since the close of our initial public offering on July 26, 2002 are as follows:

	Price Range			
	High	Low	Cash Distributions(2)	Payment Date
Year ended December 31, 2002				
Third Quarter 2002(1)	$ 20.28	$ 18.20	$ 0.3368	November 14, 2002

	Price Range			
Fourth Quarter 2002	20.10	18.65	0.4625	February 14, 2003
Year ended December 31, 2003				
First Quarter 2003	$ 21.47	$ 18.70	$ 0.4625	May 15, 2003
Second Quarter 2003	25.95	20.77	0.4625	August 14, 2003
Third Quarter 2003	28.30	23.60	0.4875	November 14, 2003
Fourth Quarter 2003	29.45	25.32	0.4875	February 13, 2004

(1) For the period from July 26, 2002 through September 30, 2002.

(2) Distributions declared associated with each respective quarter. The 2002 third quarter distribution of $0.3368 per common unit was pro-rated for the period from July 26, 2002, the date of the closing of our initial public offering of common units, through September 30, 2002, and is equivalent to a full quarterly distribution of $0.4625 per common unit.

For equity compensation plan information, see "Item 12 Security Ownership of Beneficial Owners and Management."

We are party to a credit agreement, which contains certain financial covenants that may restrict our ability to make distributions to our unitholders. For a discussion regarding this credit agreement and our obligations under this credit agreement, see "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation Credit Facilities."

Distributions of Available Cash

General. Within approximately 45 days after the end of each quarter, we will distribute all of our available cash, if any, to unitholders of record on the applicable record date.

Definition of Available Cash. Available cash generally means, for each fiscal quarter:

- all cash on hand at the end of the quarter; less
- the amount of cash reserves that our General Partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; and
  - provide funds for distributions to our unitholders and to our General Partner for any one or more of the next four quarters; plus
- all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Intent to Distribute Minimum Quarterly Distribution. We intend to distribute to holders of common units and subordinated units on a quarterly basis at least a minimum quarterly distribution of $0.4625 per quarter, or $1.85 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the common units in any quarter and we are prohibited from making any distribution to unitholders if it would cause an event of default, or if an event of default is existing, under our revolving credit facility or our term loan.

Operating Surplus, Capital Surplus and Adjusted Operating Surplus

General. All cash distributed to unitholders will be characterized as either operating surplus or capital surplus. We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. For any period, operating surplus generally means:

- our cash balance on July 26, 2002, the closing date of our initial public offering; plus
- $15.0 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for that quarter; less
- all of our operating expenses since the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

Definition of Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Adjusted operating surplus for any period generally means:

- operating surplus generated with respect to that period; less
- any net increase in working capital borrowings with respect to that period; less
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Definition of Capital Surplus. Capital surplus will generally be generated only by:

- borrowings other than working capital borrowings;

sales of debt and equity securities; and

sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterizations of Cash Distributions. We will treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes $15.0 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our unitholders. Rather this amount permits us, if we choose, to make limited distributions of cash from non-operating sources, such as asset sales, issuances of securities and long-term borrowings, which would otherwise be considered distributions of capital surplus. Any distributions of capital surplus would trigger certain adjustment provisions in our partnership agreement. We do not anticipate making any distributions from capital surplus.

Subordination Period

General. During the subordination period, the common units are entitled to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.4625 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, to the extent we have sufficient cash from our operations after payment of fees and expenses, including payments to our General Partner and establishment of cash reserves before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Definition of Subordination Period. The subordination period will generally expire on the first day of any quarter beginning after June 30, 2007, that each of the following tests are met:

distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis plus the related distribution on the 2% general partner interest during those periods; and

there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Conversion of Subordination Units. Prior to the end of the subordination period, 50% of the subordinated units, or up to 5,232,500 subordinated units, may convert into common units on a one-for-one basis immediately after the distribution of available cash to partners in respect of any quarter ending on or after:

June 30, 2005, with respect to 25% of the subordinated units; and

June 30, 2006, with respect to 25% of the subordinated units.

The early conversions will occur if, at the end of the applicable quarter, each of the following three tests are met:

distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis plus the related distribution on the 2% general partner interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

However, the second early conversion of the subordinated units may not occur until at least one year following the first early conversion of the subordinated units.

Effect of Expiration of the Subordination Period. Upon expiration of the subordination period, each outstanding subordinated unit will automatically convert into one common unit and will then participate, pro rata, with the other common units in any distributions of available cash. In addition, if the unitholders remove our General Partner other than for cause and units held by our General Partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into one common unit;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our General Partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Distributions of Available Cash from Operating Surplus During the Subordination Period

We will make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *First*, 98% to the common unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

- *Second*, 98% to the common unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

- *Third*, 98% to the subordinated unitholders, pro rata, and 2% to our General Partner, until we have distributed for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- *Thereafter*, in the manner described in " Incentive Distribution Rights" below.

Distributions of Available Cash from Operating Surplus After the Subordination Period

We will make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *First*, 98% to all unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

- *Thereafter*, in the manner described in " Incentive Distribution Rights" below.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus, up to 48%, after the minimum quarterly distribution and the target distribution levels have been achieved. Our General Partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

If for any quarter:

- we have distributed available cash from operating surplus on each common unit and subordinated unit in an amount equal to the minimum quarterly distribution; and

- we have distributed available cash from operating surplus on each outstanding common unit in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders, our General Partner and the holders of the incentive distribution rights (if other than our General Partner) in the following manner:

- *First*, 98% to all unitholders, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.5125 per unit for that quarter (the "first target distribution");

- *Second*, 85% to all unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.5875 per unit for that quarter (the "second target distribution");

- *Third*, 75% to all unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.7000 per unit for that quarter (the "third target distribution"); and

- *Thereafter*, 50% to all unitholders, pro rata, 48% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of the additional available cash from operating surplus between the unitholders and our General Partner up to the various target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Target Amount," until available cash we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests shown for our General Partner include its 2% general partner interest and assume that our General Partner has not transferred the incentive distribution rights.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.4625	98%	2%
First Target Distribution	up to $0.5125	98%	2%
Second Target Distribution	above $0.5125 up to $0.5875	85%	15%

		Marginal Percentage Interest in Distributions	
Third Target Distribution	above $0.5875 up to $0.7000	75%	25%
Thereafter	above $0.7000	50%	50%

ITEM 6. Selected Financial and Operating Data

General

The following table shows selected financial and operating data of Pacific Energy Partners, L.P., the successor to Pacific Energy and Subsidiaries (Predecessor) (as defined below) for the periods and as of the dates indicated. The data consists of the consolidated financial and operating data of the Partnership and its 100% ownership interest in PEG, whose subsidiaries consist of (i) PPS, owner of Line 2000 and the Line 63 system, (ii) PMT, owner of the PMT gathering and blending system, (iii) PT, owner of the Pacific Terminals storage and distribution system acquired on July 31, 2003, (iv) RMPS, owner of the Western Corridor and the Salt Lake City Core systems and the AREPI pipeline, and (v) RPL, the owner of a 22.22% partnership interest in Frontier. Prior to July 26, 2002, the financial and operating data for PPS, PMT, RMPS and RPL, are presented on a combined basis and constitute the Predecessor. Subsequent to July 26, 2002, the financial and operating data of PEG, PPS, PMT, RMPS and RPL are presented on a consolidated basis as successor to the Predecessor. The financial data for 2000 and 2001 are derived from the audited combined financial statements of Pacific Energy (Predecessor).

The financial data for 2000 does not include the financial position or results of operations associated with the PMT gathering and blending system purchased from EOTT Energy Partners on July 1, 2001. The financial data for 2001 includes the financial position and results of operations associated with six months of ownership of the PMT gathering and blending system. The financial data for 2002 includes the financial position and results of operations associated with a full year of ownership of the PMT gathering and blending system.

The financial and operating data for 2000 and 2001 does not include the financial position or results of operations associated with the Western Corridor or the Salt Lake City Core systems, which were purchased on March 1, 2002. The financial and operating data for 2002 includes the financial position and results of operations associated with the ten months of ownership of the Western Corridor and the Salt Lake City Core systems. Accordingly, for 2000 and 2001, references to our Rocky Mountain operations in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in the consolidated financial statements include only AREPI pipeline and Frontier pipeline (under the equity method) and do not include the Western Corridor or the Salt Lake City Core systems.

The financial data for 2000, 2001, and 2002 does not include the financial position or results of operations associated with the Pacific Terminals storage and distribution system, which was purchased on July 31, 2003. The financial data for 2003 includes the financial position and results of operations associated with five months of ownership of the Pacific Terminals storage and distribution system.

Sustaining capital expenditures are capital expenditures made 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 are made to integrate acquired assets into our existing operations. Expansion capital expenditures are made to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses and expense them as incurred.

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.

Non-GAAP Financial Measures

EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (i) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (iii) our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing and capital structure; and (iv) the viability of projects and the overall rates of return on alternative investment opportunities. We define EBITDA as net income less interest income, plus interest expense, depreciation and amortization expense and the non-cash portion of our long-term incentive plan. The Partnership is not a taxable entity. EBITDA should not be considered an alternative to net income, income before taxes, cash flows from operations, or any other measure of financial performance presented in accordance with GAAP. EBITDA is not intended to represent cash flow. Our EBITDA may not be comparable to EBITDA or similarly titled measures of other companies.

Distributable cash flow for 2003 is presented in the selected financial data. On July 26, 2002, we completed our initial public offering of common units. Accordingly, distributable cash flow is not presented for 2002, 2001 and 2000. We believe that investors benefit from having access to the same financial measures being utilized by management. Distributable cash flow is a significant financial measure used by our management to compare cash flows generated by the partnership to the cash distributions we make to our partners. This is an important financial measure for our limited partners since it is an indicator of our success in providing a cash return on their investment. Specifically, this financial measure tells investors whether or not the partnership is generating cash flows at a level that can sustain or support an increase in our quarterly cash distributions paid to partners. Lastly, distributable cash flow is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships. However, distributable cash flow is a non-generally accepted accounting principle financial measure and should not be considered as an alternative to net income, cash flow from operations, or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States. In addition, our distributable cash flow may not be comparable to distributable cash flow or similarly titled measures of other companies.

Several adjustments to net income are required to calculate distributable cash flow. These adjustments include: (i) the addition of depreciation and amortization expense; (ii) the addition of amortization of debt issue costs, which are included in interest expense; (iii) the addition of non-cash employee compensation under the long-term incentive plan, which is included in general and administrative expense; and (iv) the subtraction of sustaining capital expenditures.

The following table should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K. The table should also be read together with "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Pacific Energy Partners, L.P.			
	Years Ended December 31,			
	2003	2002(1)	2001	2000
	(in thousands)			
Consolidated Statements of Income:				
Revenue:				
Pipeline transportation	$ 101,811	$ 103,090	$ 66,331	$ 71,419
Storage and distribution revenue(2)	12,711			
Crude oil sales, net of purchases(3)	21,293	21,104	7,236	
Net revenue before operating expenses	135,815	124,194	73,567	71,419
Expenses:				
Operating	60,649	55,184	34,032	26,988
Transition costs	397	2,633	220	
General and administrative	13,705	7,515	2,787	2,672
Rate case litigation expense(4)			1,853	
Depreciation and amortization	18,865	15,919	11,368	11,873
Total expenses	93,616	81,251	50,260	41,533
Share of net income (loss) of Frontier:				
Income before rate case and litigation expense	1,459	1,904	1,569	1,738
Rate case and litigation expense	(1,621)	(557)		
Share of net income (loss) of Frontier(5)	(162)	1,347	1,569	1,738
Operating income	42,037	44,290	24,876	31,624
Other income	323	533	467	357
Interest income	156	385	320	474

	Pacific Energy Partners, L.P.			
Interest expense	(17,487)	(11,634)	(10,056)	(18,115)
Net income	$ 25,029	$ 33,574	$ 15,607	$ 14,340
Other Financial Data:				
EBITDA(6)	$ 63,424	$ 60,814	$ 36,711	$ 43,854
Distributable Cash Flow(7)	44,973			
Net cash provided by operating activities	42,382	45,793	26,406	26,319
Net cash used in investing activities	(180,332)	(101,311)	(37,203)	(3,487)
Net cash provided by (used in) financing activities	123,776	69,880	8,044	(17,571)
Capital expenditures:				
Sustaining	$ 2,149	$ 2,797	$ 3,381	$ 1,662
Transitional	351	2,039		
Expansion	8,392	806	2,433	1,825
Total capital expenditures	$ 10,892	$ 5,642	$ 5,814	$ 3,487
Balance Sheet Data (at period end):				
Net property, plant and equipment	$ 567,954	$ 404,842	$ 309,675	$ 340,889
Total assets	650,203	487,038	372,179	366,011
Total debt, including current portion	298,000	225,000	181,333	240,000
Net partners' capital (net parent investment)	295,067	215,267	157,361	117,528

Operating Data:				
West Coast Operations:				
Pipeline throughput (mbpd)(8)	151.0	162.8	158.0	166.3
Rocky Mountain Operations:				
Salt Lake City Core system throughput (mbpd)(8)(9)	65.7	70.0		
Western Corridor system throughput (mbpd)(8)(9)	16.7	15.0		
AREPI pipeline throughput (mbpd)(8)	41.8	45.6	41.1	39.4
Frontier pipeline throughput (mbpd)(8)(10)	41.7	44.4	40.5	37.4

(1) Includes our ownership of the Western Corridor and Salt Lake City Core systems from March 1, 2002.

(2) Includes our ownership of the Pacific Terminals storage and distribution system from July 31, 2003 to December 31, 2003.

(3) The above amounts are net of purchases of $358,454, $316,283 and $160,085 for 2003, 2002 and 2001, respectively. The results for 2001 include six months of gathering and blending operations from June 30, 2001.

(4) Provision for settlement expenses related to the AREPI pipeline rate case litigation.

(5)

2000 includes 12.5% of the net income of Frontier Pipeline Company. On December 17, 2001, Pacific Energy (Predecessor) acquired an additional 9.72% partnership interest in Frontier Pipeline Company. Therefore, 2001 includes 12.5% of the net income of Frontier Pipeline Company for the period January 1, 2001 through December 16, 2001 and 22.22% for the balance of the year. The data for 2002 and 2003 includes 22.22% of the net income of Frontier Pipeline Company.

(6)

A reconciliation from reported net income to EBITDA is as follows:

	Years Ended December 31,			
	2003(*)	2002(*)	2001	2000
	(in thousands)			
Net income	$ 25,029	$ 33,574	$ 15,607	$ 14,340
Interest income	(156)	(385)	(320)	(474)
Interest expense	17,487	11,634	10,056	18,115
Depreciation and amortization	18,865	15,919	11,368	11,873
Non-cash portion of our long-term incentive plan	2,199	72		
EBITDA	$ 63,424	$ 60,814	$ 36,711	$ 43,854

(*) Includes our ownership of Pacific Terminals storage and distribution system from July 31, 2003 and our ownership of the Western Corridor and Salt Lake City Core systems from March 1, 2002.

(7)

On July 26, 2002, we completed our initial public offering of common units. Accordingly, distributable cash flow is not presented for 2002, 2001, and 2000. A reconciliation from reported net income to distributable cash flow for the year ended December 31, 2003 is as follows:

	Year Ended December 31, 2003
	(in thousands)
Net income	$ 25,029
Depreciation and amortization	18,865
Amortization of debt issue costs	1,028
Non-cash employee compensation under long-term incentive plan	2,199
Sustaining capital expenditures	(2,149)
Distributable cash flow	$ 44,973

(8)

Throughput is the total number of barrels per day transported on a pipeline system. We recognize throughput at the time a barrel of crude oil is delivered to its ultimate delivery point.

(9)
This amount represents throughput for the ten months ended December 31, 2002, as this system was acquired on March 1, 2002.

(10)
This figure represents 100% of the throughput on Frontier pipeline.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

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 consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the consolidated financial position, statements of income and statements of cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system acquired on July 31, 2003, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and Salt Lake City Core systems, and AREPI pipeline, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company, a Wyoming general partnership ("Frontier").

Prior to July 26, 2002, the date of the Partnership's initial public offering, the financial data and results of operations for PPS, PMT, RMPS and RPL, are presented on a combined basis and constitute the Predecessor.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing and distributing crude oil in California and the Rocky Mountain region. We completed our initial public offering of common units on July 22, 2002.

We operate primarily in California, Colorado, Montana, Wyoming and Utah and conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations. We generate revenue principally through three crude oil and other dark products related activities: pipeline transportation services, storage and distribution services, and buying, gathering, blending and selling activities.

Our West Coast operations consist of Line 2000, the Line 63 system, the Pacific Terminals storage and distribution system and the PMT gathering and blending system. We transport crude oil produced in California's San Joaquin Valley and the California Outer Continental Shelf to third party refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. We also provide crude oil and other dark products storage and distribution services to third party refineries and terminal facilities in the Los Angeles Basin. We have recently announced that we are proceeding with the next phase of development of our Pier 400 marine import terminal project in the Port of Los Angeles, as described below. In addition, in our West Coast operations, we purchase, gather, blend and resell crude oil, in large measure as a means of generating additional volumes on our pipelines.

Our Rocky Mountain operations consist of the Western Corridor system, the Salt Lake City Core system, the AREPI pipeline and RPL's interest in Frontier pipeline. We transport crude oil produced in Canada and the Rocky Mountain region for delivery to refineries in Montana, Wyoming, Colorado and Utah. Our pipelines deliver crude oil to refineries by direct connection or indirectly through connections with third party pipelines. We recently announced that we have entered into an acquisition agreement and a non-binding letter of intent to extend our Rocky Mountain pipeline network into Alberta, Canada as described below.

Cash distributions

Our principal business objective is to generate stable and increasing cash flows by being a leading provider of pipeline transportation and other midstream services to the North American energy industry. We seek to achieve our objective by executing the following strategies:

- Use our strategic position in our core market areas to maximize throughput on our pipelines and utilization of our storage facilities.

- Control our operating and capital costs while maintaining the safety and operational integrity of our assets.

Minimize our exposure to commodity price volatility.

Pursue strategic and accretive acquisitions and new projects that enhance and expand our core business.

Our ability to execute this acquisition and development strategy successfully is dependent on the price we pay for the acquisitions or the cost of development relative to the assets' future cash flows.

Our cash distributions to unitholders may vary over time with the cash flow from our operating activities, which are impacted by the revenue and cost variables described below. Our cash distributions may also vary over time with the level of sustaining capital expenditures. These expenditures are required 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.

During the subordination period, the common units are entitled to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.4625 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, to the extent we have sufficient cash from our operations after payment of fees and expenses, including payments to our General Partner and establishment of cash reserves, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. See "Item 5 Market Price of and Distributions on the Registrant's Common Equity and Related Unitholder Matters" regarding subordinated units and the subordination period.

Key Events in 2003 and Recent Developments

The key events in 2003 were the closing of the $173 million EPTC acquisition by PT on July 31, 2003 and the related equity offering which raised $93 million of net proceeds. The financial data for 2003 includes the financial position and results of operations associated with five months of ownership of the Pacific Terminals storage and distribution system. This acquisition supported a $0.10 per unit, or 5.4%, increase to a $1.95 per unit annual distribution rate.

In February 2004, we entered into a definitive share purchase and sale agreement to acquire the Rangeland Pipeline System from BP Canada Energy Company, and we entered into a non-binding letter of intent to purchase the Mid Alberta Pipeline ("MAPL") assets, also in Alberta, from Imperial Oil Resources. The acquisition price for the Rangeland Pipeline System is $130 million (Canadian) plus an estimated $26 million (Canadian) for line fill, working capital, transaction costs and transition capital expenditures. At an exchange rate of $1 U.S. = $1.3187 Canadian, as of March 8, 2004, the total purchase price would be approximately U.S. $118 million. Closing of the transaction is expected in the second quarter of 2004, following receipt of regulatory approvals and fulfillment of other customary closing conditions. The MAPL transaction is subject to completion of a definitive purchase and sale agreement, receipt of regulatory approvals and fulfillment of such other closing conditions as are included in the definitive agreement. See "Items 1 and 2 Business and Properties Rocky Mountain Operations".

We expect to fund the Canadian acquisitions with borrowings under a new revolving credit facility being negotiated and with the proceeds from the issuance of additional common units so as to maintain an approximate 50 percent debt to total capitalization ratio.

The final key event was completion of the feasibility study for Pier 400 marine import terminal project in the Port of Los Angeles, and, in early 2004, the entering into a project development agreement with subsidiaries of Valero Energy Corporation and the commencement of environmental review for permitting purposes. See "Items 1 and 2 Business and Properties West Coast Operations" for more information.

Business Fundamentals

Pipeline Transportation

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

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

The availability of crude oil for transportation on our pipelines is dependent in part on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain systems. With the passage of time, production of crude oil in an individual well naturally declines, which can in the short term be offset in whole or in part by additional drilling or the implementation of recovery enhancement measures. In the San Joaquin Valley, California and in the California Outer Continental Shelf ("OCS"), production is generally declining. The expected development of the Rocky Point field in the OCS and, if it occurs, the closure of the Shell Bakersfield refinery, will, we believe, provide an increase in the supply of crude oil available to be transported by us to the Los Angeles Basin, offsetting some or all of the effects of production decline in the short term. In addition, we acquired the Pacific Terminals storage and distribution assets and are developing the Pier 400 project to participate in the marine import business, which is growing as a result of local production decline. In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and we recently announced an agreement and a non-binding letter of intent to acquire two pipeline systems to access significant supplies of Canadian crude oil and synthetic crude oil which we expect will replace any Rocky Mountain production decline and meet growing demand in the Rocky Mountain region. See "Items 1 and 2 Business and Properties Rocky Mountain Operations".

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (the "CPUC"). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual restraints. Tariffs on Line 63, which are cost-of-service based tariffs, are based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our Rocky Mountain pipelines are regulated by either the FERC or the Wyoming Public Service Commission generally under a cost-of-service approach.

Storage and Distribution

We provide storage and distribution services to refineries in the Los Angeles Basin. The fundamental items impacting our storage and distribution revenue are the amount of storage capacity we have under lease, the lease rates for that capacity and the length of each lease. Demand for crude oil storage capacity tends to be more stable over time and leases for crude oil storage capacity are usually long term (more than one year). Demand for other dark products storage capacity is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for other dark products storage capacity are usually short term (less that one year). One of our business goals is to convert a number of other dark products tanks to more flexible crude oil service (which can also accommodate other dark products).

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

Gathering and Blending

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

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

Acquisitions and New Projects

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

Operating Expense

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to run the various pump stations along our pipelines. Major maintenance costs can vary with age and also with regulation requiring inspections at defined intervals. Unanticipated costs can include the costs of cleanup of any oil spills to the extent not covered by insurance.

Employees

The Partnership does not have any employees. All our personnel are employed by our General Partner. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us. Please read "Item 13 Certain Relationships and Related Transactions" below.

Critical Accounting Policies and Estimates

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

We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired and liabilities assumed. The valuation of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilize in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment.

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

We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated it is probable that cleanup costs are or will be required and may be reasonably estimated. In making these estimates, we consider information that is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions. We use outside environmental consultants to assist us in making these estimates. In addition, generally accepted accounting principles in the United States of America require us to establish liabilities for the costs of asset retirement obligations

when the retirement date is determinable. We will record such liabilities only when such date is determinable.

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

Our inventory of displacement oil, pipeline linefill and minimum tank volumes is carried in our accounts at the lower of cost and market value. This inventory is held for our long-term use and for the operation of our pipelines and storage facilities and as such is recorded in our property and equipment balance. As oil prices tend to be cyclical, we are exposed to the potential for a write-down to market value. Such a write-down would be a non-cash expense but would not be realized, if at all, until we were to sell such inventory for a price less than our cost.

Results of Operations

Year ended December 31, 2003 Compared to Year Ended December 31, 2002

Summary

	Year ended December 31,			
	2003	2002	Change	Percent

	Year ended December 31,			
	(In thousands)			
Net income	$ 25,029	$ 33,574	$ (8,545)	-25%

Basic and diluted net income per limited partner unit for 2003 was $1.10 and $1.09 per limited partner unit, respectively. We completed our initial public offering in July 2002, so there is no comparable per unit calculation for 2002.

Net income for 2003 includes five months of operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003. Net income for 2002 includes the results of the Western Corridor and Salt Lake City Core system assets for the ten months following the acquisition of these assets on March 1, 2002.

The additional income generated by the Pacific Terminals storage and distribution system assets and the Western Corridor and Salt Lake City Core systems was more than offset by a combination of lower West Coast pipeline volumes and increased expenses. The increased expenses include increased general and administrative expense associated with our growth and becoming a public company in July 2002, and increased interest expense associated with our post-IPO capital structure.

Segment Information

	Year ended December 31,			
West Coast	**2003**	**2002**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 42,664	$ 38,323	$ 4,341	11%
Operating data:				
Pipeline throughput (bpd)	151.0	162.8	(11.8)	-7%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system. This increase was partially offset by a reduction in pipeline transportation revenue as average daily pipeline throughput decreased to 151,000 barrels per day for the year ended December 31, 2003, compared to 162,800 barrels per day for the prior year. California OCS throughput to the Los Angeles Basin was lower during 2003, compared to 2002, primarily due to maintenance downtime at both on-shore processing and off-shore production facilities. Refinery maintenance activities and increased mid-barrel crude oil ("MBCO") demand in San Francisco reduced throughput to the Los Angeles Basin. Increased demand for light crude oil at refineries in Bakersfield also reduced throughput to the Los Angeles Basin. In addition, the natural decline of OCS and San Joaquin Valley production reduced available crude supplies.

	Year ended December 31,			
Rocky Mountains	**2003**	**2002**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 13,078	$ 13,482	$ (404)	-3%
Operating data (bpd):				
Salt Lake City Core system	65.7	70.0	(4.3)	-6%
Western Corridor system	16.7	15.0	1.7	11%
AREPI pipeline	41.8	45.6	(3.8)	-8%
Frontier pipeline	41.7	44.4	(2.7)	-6%

Operating income for the 2002 period included only ten months of results for the Western Corridor and Salt Lake City Core systems. The Partnership incurred significant transition costs in the 2002 period, but those costs were largely eliminated in the 2003 period. The reduction in transition costs in 2003 was offset, however, by increased maintenance expense. Refinery maintenance in the first half of 2003 resulted in reduced throughput to Salt Lake City through our various pipeline systems.

Statement of Income Discussion and Analysis

Year ended December 31,

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Pipeline transportation revenue	$ 101,811	$ 103,090	$ (1,279)	-1%

Rocky Mountain pipeline transportation revenue increased by $3.3 million compared to the corresponding period in 2002 due to revenue generated by the Western Corridor and Salt Lake City Core systems for twelve months in 2003 compared to ten months in 2002. The increase in Rocky Mountain pipeline transportation revenue for 2003 was more than offset by a decrease in West Coast pipeline transportation revenue due to lower throughput.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Storage and distribution revenue	$ 12,711	$	$ 12,711	

The acquisition of the Pacific Terminals storage and distribution system resulted in storage and distribution revenue of $12.7 million for the period ended December 31, 2003.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Crude oil sales	$ 379,747	$ 337,387	$ 42,360	13%
Crude oil purchases	(358,454)	(316,283)	42,171	13%
Crude oil sales, net of purchases	$ 21,293	$ 21,104	$ 189	1%

The increase in crude oil sales and purchases for 2003 was primarily the result of higher crude oil prices. We consider this activity to be complementary to our pipeline transportation operations.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Operating expenses	$ 60,649	$ 55,184	$ 5,465	10%

The increase in operating expense was related primarily to the acquisitions of the Pacific Terminals storage and distribution system and a full year of operations of the Western Corridor and Salt Lake City Core systems. We are also experiencing higher operating costs as a result of increased requirements for pipeline and storage tank inspections, and increased costs for property taxes and insurance.

Operating expense for our Rocky Mountain operations increased by $3.2 million due to a full year of operations of the Western Corridor and Salt Lake City Core systems compared to ten months of operations for the corresponding period in 2002 and a return to a normal level of maintenance activity. These increases were partially offset by a reduction of $2.1 million in transition cost savings. Operating expense for our West Coast operations increased by $3.8 million. For 2003, we incurred five months of operating expense relating to the Pacific Terminals storage and distribution system. Operating expense for our West Coast pipeline and gathering and blending operations decreased due to lower field operating expenses and reduced right-of-way expense resulting from the relinquishment of certain unused rights-of-way on Line 2000.

Year ended
December 31,

	2003	2002	Change	Percent
	(In thousands)			
Transition costs	$ 397	$ 2,633	$ (2,236)	-85%

Transition costs in 2003 consisted only of employee transition bonus payments, whereas transition costs in 2002 consisted of payments to the seller of the Western Corridor and Salt Lake City Core systems for certain interim operations support, financial systems services and employee transition bonuses.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
General and administrative expense	$ 13,705	$ 7,515	$ 6,190	82%

This increase includes $3.2 million of expense for long-term incentive awards made in December 2002 and in 2003. The balance of the increase is attributable to additional costs incurred as a result of the acquisition of the Western Corridor and Salt Lake City Core systems and higher costs of being a public company, including costs incurred as a result of new stock exchange and SEC rules.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Depreciation and amortization	$ 18,865	$ 15,919	$ 2,946	19%

The increase in depreciation and amortization includes $1.2 million for a full year of depreciation on the Western Corridor and Salt Lake City Core systems in 2003, compared to ten months in 2002, and $1.4 million for five months of depreciation on the Pacific Terminals storage and distribution system.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Share of net income (loss) of Frontier:				
Income before rate case and litigation expense	$ 1,459	$ 1,904	$ (445)	-23%
Rate case and litigation expense	(1,621)	(557)	1,064	191%
Share of net income (loss) of Frontier	$ (162)	$ 1,347	$ (1,509)	-112%

Our decreased share of Frontier net income was attributable to expenses for a contract dispute and two tariff rate related matters. These matters relate to early 2002 and prior years, so there is no impact on Frontier's current rates or revenues.

	Year ended December 31,			
	2003	2002	Change	Percent
	(In thousands)			
Interest expense	$ 17,487	$ 11,634	$ 5,853	50%

$1.2 million of the increase in interest expense was attributable to an increase in borrowings during the 2003 period to finance the acquisition of the Pacific Terminals storage and distribution system. The remaining increase was primarily due to an increase in the interest rate on outstanding borrowings during 2003. Our interest rate on outstanding borrowings averaged 6.7% for 2003, as compared to 5.0% during 2002, reflecting our interest rate swap agreements, in which we fixed the interest rates on $170.0 million of our post initial public offering debt.

Year ended December 31, 2002 Compared to Year Ended December 31, 2001

Summary

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
Net income	$ 33,574	$ 15,607	$ 17,967	115%

This increase was due to the acquisition of the Western Corridor and Salt Lake City Core systems, higher volumes and tariffs on Line 2000 and the Line 63 system, and a full year of operation and improved results from our PMT gathering and blending system.

Segment information

	Year ended December 31,			
West Coast	2002	2001	Change	Percent
	(In thousands)			
Operating income	$ 38,323	$ 25,191	$ 13,132	52%
Operating data:				
Pipeline throughput (bpd)	162.8	158.0	4.8	3%

This increase was primarily due to a full year of operation and improved results of the PMT gathering and blending system and improved West Coast pipeline revenues as a result of increased long-haul throughput volumes and higher average tariff rates in 2002. The strong refinery demand in the Los Angeles Basin, coupled with the absence of any significant production or refinery outages, accounted for the increased volumes in 2002.

	Year ended December 31,			
Rocky Mountains	2002	2001	Change	Percent
	(In thousands)			
Operating income	$ 13,482	$ 2,472	$ 11,010	445%
Operating data (bpd):				
Salt Lake City Core system	70.0		70.0	
Western Corridor system	15.0		15.0	
AREPI pipeline	45.6	41.1	4.5	11%
Frontier pipeline	44.4	40.5	3.9	10%

The increase in operating income was primarily due to the acquisition of the Western Corridor and Salt Lake City Core systems. Additionally, operating income was higher due to reduced rate case and litigation expense in 2002.

Statement of Income Discussion and Analysis

	Year ended December 31,			
	2002	2001	Change	Percent

	Year ended December 31,			
	(In thousands)			
Pipeline transportation revenue	$ 103,090	$ 66,331	$ 36,759	55%

This increase was primarily due to our Rocky Mountain operations, where revenue increased by $32.8 million due to revenue generated by the Western Corridor and Salt Lake City Core systems. In addition, pipeline transportation revenue from our West Coast operations increased by $6.8 million. The West Coast pipeline transportation revenue increase was due to the increase in long-haul throughput volumes of approximately 4,800 bpd, or 3%, and an increase in average tariff rates. The strong refinery demand for crude oil by the Los Angeles Basin refiners and the absence of any significant refinery or production outages in our delivery market account for the increased volumes compared to 2001. This increase in West Coast revenue was partially offset by $3.1 million attributable to the elimination of pipeline transportation revenue that was previously charged to the seller of the PMT gathering and blending system as a third party during the first six months of 2001.

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
Crude oil sales	$ 337,387	$ 167,321	$ 170,466	102%
Crude oil purchases	(316,283)	(160,085)	156,198	98%
Crude oil sales, net of purchases	$ 21,104	$ 7,236	$ 13,868	192%

On July 1, 2001, we acquired the PMT gathering and blending system. We consider this activity to be complementary to our pipeline transportation operations. The increase in crude oil sales net of purchases is attributed to a full year of operations in 2002 as compared to six months in 2001.

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
Operating expense	$ 55,184	$ 34,032	$ 21,152	62%

The increase in operating expense related primarily to our Rocky Mountain operations, where operating expenses increased by $16.7 million, principally as a result of the acquisition in 2002 of the Western Corridor and Salt Lake City Core systems. Operating expenses for our West Coast operations increased $4.4 million due primarily to field operating, blending and trucking expenses related to our PMT gathering and blending system acquired in mid-2001.

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
General and administrative expense	$ 7,515	$ 2,787	$ 4,728	170%

The general and administrative expense increase was due in part to the acquisition of the Western Corridor and Salt Lake City Core systems, and a full year of PMT reflected in operations. In addition, we incurred an additional $1 million, approximately, in G&A expenses in 2002 as a result of the transition from a private company to a publicly traded company and to comply with new SEC and stock exchange regulations.

	Year ended December 31,			
	2002	2001	Change	Percent

	Year ended December 31,			
	(In thousands)			
Depreciation and amortization expense	$ 15,919	$ 11,368	$ 4,551	40%

The increase in depreciation and amortization is primarily attributed to $4.2 million of depreciation expense related to the acquisition of the Western Corridor and Salt Lake City Core systems on March 1, 2002.

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
Share of net income of Frontier:				
Income before rate case and litigation expense	$ 1,904	$ 1,569	$ 335	21%
Rate case and litigation expense	(557)		(557)	
Share of net income of Frontier	$ 1,347	$ 1,569	$ (222)	-14%

This decrease was due to lower tariff revenue, which was partially offset by the increase in our ownership interest from 12.5% to 22.22% in December 2001, and rate case and litigation expense.

	Year ended December 31,			
	2002	2001	Change	Percent
	(In thousands)			
Interest expense	$ 11,634	$ 10,056	$ 1,578	16%

Increased interest expense of $1.6 million was due to an increase in the average daily debt balances, which were $235.5 million in 2002 as compared to $203.9 million in 2001. The interest rate on outstanding borrowings in 2002 averaged 5.0% compared to 4.7% in 2001.

Liquidity and Capital Resources

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

We intend to finance the recently announced Canadian acquisitions through a combination of borrowings under a new $100 million (Canadian) revolving credit facility (equivalent to approximately U.S. $76 million based on the exchange rate on March 8, 2004) that is currently being negotiated and the proposed issuance of additional common units. The final structure of the acquisition financing will depend on market conditions existing prior to the completion of the acquisitions.

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

We expect to fund future acquisitions and new projects with the proceeds of borrowings under our existing and planned revolving credit facilities and the issuance of additional units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The SEC declared the registration statement effective on August 8, 2003. At December 31, 2003, we have approximately $412 million of remaining availability under this registration statement.

We intend to draw down on this shelf registration statement to finance a portion of our future acquisitions and development projects, including the Canadian acquisitions and the Pier 400 Project.

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

Operating, Investing and Financing Activities

	Year ended December 31,		
	2003	2002	Change
		(In thousands)	
Net cash provided by operating activities	$ 42,382	$ 45,793	$ (3,411)
Net cash used in investing activities	(180,332)	(101,311)	(79,021)
Net cash provided by financing activities	123,776	69,880	53,896

Net cash provided by operating activities

The decrease in the net cash from operating activities of $3.4 million, or 7%, was the net result of higher operating income, offset by increased interest expense relating to our post initial public offering capital structure and an increase in cash used for working capital.

Net cash used in investing activities

The amounts in 2003 and 2002 related primarily to our acquisition activities. On July 31, 2003, we acquired PT's storage and distribution system for $173.0 million, including a net cash outlay of $169.7 million. In 2002, we acquired the Western Corridor and Salt Lake City Core systems for approximately $107.0 million with a cash outlay of $95.7 million in 2002 (the balance was paid in 2001). Capital expenditures were $10.9 million in 2003, of which $2.1 million related to sustaining capital projects, $0.3 million related to the transition of RMPS and the Pacific Terminals storage and distribution system, and $8.4 million related to expansion (see "Capital requirements" below). In 2002, capital expenditures were $5.6 million, of which $2.8 million related to sustaining capital projects, $2.0 million related to the transition of RMPS assets, and $0.8 million related to expansion.

Net cash provided by financing activities

The amount in 2003 of $123.8 million includes proceeds of $73.0 million under our revolving credit facility and net proceeds of $92.9 million, after deducting the related redemption of common units, from an equity offering completed on August 25, 2003, which were used to fund the acquisition of the Pacific Terminals storage and distribution system. The cash provided from financing activities in 2003 is net of $42.1 million in distributions to our limited partners and our General Partner. The 2002 amount of $69.9 million includes capital contributed by members to PEG prior to our initial public offering of $8.8 million and distributions to members by PEG of $16.0 million prior to our initial public offering. In March 2002, net proceeds of $87.0 million from notes payable were used to fund the acquisition of the Western Corridor and Salt Lake City Core systems. In connection with our initial public offering, net proceeds of $151.1 million from the issuance of common units were used to repay a similar amount of debt. Proceeds of $225.0 million from the term loan were used to pay debt issuance costs of $5.3 million, repay $114.6 million in debt and fund distributions of $105.1 million to our General Partner. Distributions to the limited and general partner interests subsequent to our initial public offering were $7.2 million in 2002.

Year ended December 31,		
2002	2001	Change
	(In thousands)	

	Year ended December 31,		
Net cash provided by operating activities	$ 45,793	$ 26,406	$ 19,387
Net cash used in investing activities	(101,311)	(37,203)	(64,108)
Net cash provided by financing activities	69,880	8,044	61,836

Net cash provided by operating activities

The increase in the net cash from operating activities of $19.4 million, or 73%, was primarily associated with the increase in net income related to the acquisition of the PMT gathering and blending system and the Western Corridor and Salt Lake City Core systems.

Net cash used in investing activities

The increase in net cash used in investing activities of $61.9 million was primarily associated with the acquisition of the Western Corridor and Salt Lake City Core systems. Capital expenditures were $5.6 million in 2002, of which $2.8 million related to maintenance projects, $2.0 million related to the transition of RMPS assets, and $0.8 million related to expansion. Capital expenditures were $5.8 million in 2001, of which $3.4 million related to maintenance and $2.4 million related to expansion.

Net cash provided by financing activities

Prior to our initial public offering in July 2002, distributions to members by PEG were $16.0 million and $22.8 million in 2002 and 2001, respectively. Capital contributed by members to PEG prior to our initial public offering was $8.8 million and $90.6 million in 2002 and 2001, respectively. In March 2002, net proceeds of $87.0 million from notes payable were used to fund the acquisition of the Western Corridor and Salt Lake City Core systems and in 2001 we repaid $63.6 million in long-term debt. In connection with our initial public offering, net proceeds of $151.1 million from the issuance of common units were used to repay a like amount of debt. Proceeds of $225.0 million from the term loan were used to pay debt issuance costs of $5.3 million, repay $114.6 million in debt, and fund distributions of $105.1 million to our General Partner. Distributions to the limited and general partner interests subsequent to our initial public offering were $7.2 million in 2002.

Capital Requirements

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

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

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

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

The following table summarizes sustaining, transitional and expansion capital expenditures for the periods presented:

	Year Ended December 31,		
	2003	2002	2001
	(in thousands)		
Sustaining capital expenditures	$ 2,149	$ 2,725	$ 3,381
Transitional capital expenditures	351	2,039	
Expansion capital expenditures	8,392	878	2,433

	Year Ended December 31,		
Total	$ 10,892	$ 5,642	$ 5,814

We have forecasted total capital expenditures of $16 million in 2004, including up to $5 million for the Pier 400 Project, $7 million for other expansion projects, $1 million for transition capital projects and $3 million for sustaining capital projects. In order to maintain sufficient availability under our credit facility, we expect to issue additional common units in 2004 to finance some or all of the expansion projects we undertook in late 2003 and plan to undertake in 2004.

Credit Facilities

Our long-term debt obligations at December 31, 2003 and 2002 are shown below:

	December 31, 2003	December 31, 2002
	(in thousands)	
Senior secured revolving credit facility	$ 73,000	$
Senior secured term loan	225,000	225,000
Total	298,000	225,000
Less current portion		
Long-term debt	$ 298,000	$ 225,000

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

The revolving credit facility is a $200.0 million facility that is available for general partnership purposes, including working capital, letters of credit, distributions to unitholders and to finance future acquisitions. The revolving credit facility also has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders. Borrowings under the revolving credit facility are limited by various financial covenants that are set forth in the credit agreement. As of December 31, 2003, we were in compliance with all covenants under the credit agreement. At December 31, 2003, PEG had borrowed $73.0 million under its revolving credit facility; no letters of credit were outstanding as of that date.

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

We may prepay all loans under the revolving credit facility and the term loan. 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 assets sold other than in the ordinary course of business and the net proceeds of new senior secured debt offerings, subject to certain exceptions.

Effective December 12, 2003, PEG amended its credit agreement to reduce the interest rates and other fees. Subject to certain limited exceptions, indebtedness under the revolving credit facility and the term loan now 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 0.25% for the term loan) or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00% for the revolving credit facility and ranging from 2.00% to 2.25% for the term loan. 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.

PEG incurs a commitment fee which ranges from 0.125% to 0.375% per annum on the unused portion of the revolving credit facility. Under the credit agreement, as amended, 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, as amended, contains other 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;
- repurchase or redeem units;
- make certain negative pledges and grant certain liens;
- sell, transfer, assign or convey assets;
- make certain loans and investments;
- enter into a new line of business;
- transact business with affiliates;
- enter into agreements restricting loans or distributions made by PEG's subsidiaries to us or PEG; or
- participate in certain hedging and derivative activities.

The credit agreement, as amended, also contains covenants requiring PEG, including certain of its subsidiaries, to maintain:

- a ratio of maximum total funded debt to consolidated EBITDA (each as defined in the credit agreement) of up to 4.25:1. This ratio will be tested quarterly on a rolling four-quarter basis and upon each incurrence of debt;
- a maximum of debt to total capital of 70%; and
- a minimum interest coverage ratio (as defined in the credit agreement) of 3.00:1 to be tested quarterly on a trailing four-quarter basis.

Each of the following is an event of default under the facilities:

- failure to pay any principal, interest, fees, expenses or other amounts;
- failure to observe any agreement, security instrument, obligation or covenant included in the credit agreement or in any guaranty, subject to various cure provisions;
- judgments against us, our General Partner or any of our subsidiaries in excess of certain allowances;
- default under other indebtedness of PEG and the guarantors of the facilities' indebtedness in excess of a threshold amount;

certain ERISA events involving us or our subsidiaries;

bankruptcy or insolvency events involving us, our General Partner or our subsidiaries;

failure of any representation or warranty to be materially true and correct; and

a change of control (as defined in the credit agreement).

As of December 31, 2003, we were in compliance with all covenants under the credit agreement.

As of December 31, 2003, we had available but undrawn credit of $30 million under the revolving credit facility, together with an additional $77 million available for acquisitions for up to 270 days. These amounts could be increased based on an acquired business's earnings before interest, taxes, depreciation and amortization ("EBITDA") with the acceptance of the administrative agent for our credit facilities.

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. 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 6.50%. These interest rate swap agreements are described further in "Note 1 Summary of Significant Accounting Policies" in the accompanying consolidated financial statements and "Item 7A Quantitative and Qualitative Disclosures about Market Risk."

Contractual Obligations

In the performance of our operations, we are bound by certain contractual obligations. Following is a summary of our monetary contractual obligations as of December 31, 2003.

	Payments due by period (in thousands)				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt principal repayments	$ 298,000	$	$ 3,375	$ 77,500	$ 217,125
Right of way obligations(1)	69,407	3,378	7,020	7,623	51,386
Operating lease obligations	3,731	1,113	1,870	748	
Total	$ 371,138	$ 4,491	$ 12,265	$ 85,871	$ 268,511

(1) Right-of-way obligations reflect our commitment for the next 15 years assuming the current right-of-way agreements will be renewed during the period.

Long-term Debt Principal Repayments

We expect to refinance the debt maturities in the "3-5 year" and "more than 5 year" categories above through an extension of existing credit facilities, new credit facilities and/or through the issuance of bonds or long term notes.

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. The 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 $2.9 million, $3.3 million and $5.2 million in 2003, 2002 and 2001, respectively.

Off-Balance Sheet Arrangements

The Partnership has no off-balance sheet arrangements. For a description of certain operating leases please see "Note 5 Leases" to the accompanying consolidated financial statements.

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2003, 2002 or 2001.

Environmental Matters

Our transportation and storage operations are subject to extensive regulation under federal, state and local environmental laws concerning, among other things, the generation, handling, transportation and disposal of hazardous materials, and we may be, from time to time, subject to environmental cleanup and enforcement actions.

The accompanying balance sheet includes reserves for environmental costs that relate to existing conditions caused by past operations. Estimates of ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation at most locations, the number of remediation alternatives available, the uncertainty of potential recoveries from third parties and the evolving nature of environmental laws and regulations.

Based on the information presently available, it is the opinion of management that our environmental costs, to the extent they exceed recorded liabilities, will not have a material adverse effect on our financial condition.

Recent Accounting Pronouncements

In May 2003, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 150 ("SFAS No. 150"), *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*. This statement establishes standards for the measurement and classification of certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise effective the first interim period beginning after June 15, 2003. The adoption of this standard did not have any impact on our consolidated financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and should be applied prospectively. However, provisions related to SFAS No. 133 Implementation Issues effective for fiscal quarters beginning prior to June 15, 2003 should continue to be applied in accordance with their respective dates. The adoption of this standard did not have any impact on our consolidated financial position or results of operations.

In July 2002, the FASB issued 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 our consolidated financial position or results of operations.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN46R).* FIN46R requires companies to evaluate variable interest entities for specific characteristics to determine whether additional consolidation and disclosure requirements apply. The transition guidance requires the application of either FIN 46 or FIN 46R to all special-purpose entities (SPEs) no later than the end of the first reporting period ending after December 15, 2003 and immediately to all entities created after January 31, 2003. The adoption of FIN 46 and FIN 46R has not and is not expected to have a material impact on our consolidated financial statements.

In December 2003, the SEC issued Staff Accounting Bulletin (SAB) No. 104, Revenue Recognition (SAB No. 104), which codifies, revises and rescinds certain sections of SAB No. 101, Revenue Recognition, in order to make this interpretive guidance consistent with current authoritative accounting and auditing guidance and SEC rules and regulations. The changes noted in SAB No. 104 did not have a material effect on our consolidated results of operations, consolidated financial position or consolidated cash flows.

ITEM 7A. 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.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our minimal exposure to market price volatility related to our inventory or future sales of crude oil. We do not enter into speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying consolidated balance sheets. Although we generally do not own the crude oil that we transport in our pipelines, in our PMT operations we purchase crude oil for subsequent blending, transportation and resale primarily in the Los Angeles Basin. Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. In 2003 and 2002, "crude oil sales, net of purchases" were net of $0 and $0.2 million respectively, reflecting changes in the fair value of PMT's derivative instruments for its marketing activities. In addition, changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital, until the related revenue is reflected in the consolidated statements of income. As of December 31, 2003, $0.2 million relating to the changes in the fair value of derivative instruments was included in "accumulated other comprehensive income."

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. 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 6.50% (including the current applicable margin of 2.25%).

As of December 31, 2003, interest rates, as measured by current 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 $5.4 million on the aggregate interest rate hedge, which is recorded as a liability at December 31, 2003. The $5.4 million liability is shown on the consolidated balance sheet in two components, a current liability of $4.8 million, and a long term liability of $0.6 million. The unrealized loss reflecting the decline in interest rates from the inception of the swaps, is shown in "accumulated other comprehensive income," a component of partners' capital, and not in the consolidated income statement. Should interest rates remain unchanged from the December 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 6.50%.

We are subject to risks resulting from interest rate fluctuations as the interest cost on the remaining $55.0 million outstanding under our term loan and $73.0 million outstanding under our revolving credit facility is based on variable rates. If the LIBOR rate were to increase 1.0% in 2004 as compared to the rate at December 31, 2003, our interest expense for 2004 would increase $1.3 million based on the outstanding debt at December 31, 2003, which has not been hedged.

ITEM 8. Financial Statements and Supplementary Data

The information required here is included in the report as set forth in the "Index to Financial Statements" on page F-1.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures

As of the year ended December 31, 2003, Irvin Toole, Jr., Chief Executive Officer of our General Partner, and Gerald A. Tywoniuk, Chief Financial Officer of our General Partner, evaluated the effectiveness of our disclosure controls and procedures. Based on their evaluation, they believe that:

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

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

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during the year ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part III

ITEM 10. Directors and Executive Officers of Pacific Energy Partners, L.P.

The following table shows information for the directors and executive officers of Pacific Energy GP, Inc. Executive officers and directors are elected for one-year terms.

Name	Age	Position with the General Partner
Douglas L. Polson	62	Chairman of the Board of Directors
Philip F. Anschutz	64	Director
Clifford P. Hickey	44	Director
David L. Lemmon	61	Director
Jim E. Shamas	69	Director
Irvin Toole, Jr.	62	President, Chief Executive Officer and Director
David E. Wright	59	Executive Vice President, Corporate Development and Marketing
Gerald A. Tywoniuk	42	Senior Vice President, Chief Financial Officer and Treasurer
Lynn T. Wood	52	Vice President, General Counsel and Secretary
Lyle B. Boarts	60	Vice President, Human Resources
Arthur G. Diefenbach	53	Vice President, Operations and Technical Services West Coast
Jesse G. Metcalf	53	Vice President, Operations and Technical Services Rocky Mountains
John Tsouvalas	45	Vice President, Marketing and Business Development West Coast
Gary L. Zollinger	55	Vice President, Marketing and Business Development Rocky Mountains
Harsha M. Tank	41	Controller

Douglas L. Polson was elected Chairman of the Board of Directors in December 2001. He has been Chairman of the Board of Directors of Pacific Energy Group LLC since August 2001 and Chairman of the Members Committee of Pacific Pipeline System LLC from July 1999 to April 2002. Mr. Polson served as Vice President and a director of The Anschutz Corporation and Anschutz Company for more than five years until October 2002. Mr. Polson served on the boards of directors of Southern Pacific Rail Corporation from 1988 to 1996 and Qwest Communications International, Inc. from February 1997 to 2000.

Philip F. Anschutz was elected to the Board of Directors in December 2001. Mr. Anschutz has served as the Chairman of the Board of Directors of The Anschutz Corporation, which he founded in 1965, and Anschutz Company, its parent, for more than five years. Through their subsidiaries and affiliates, Anschutz Company and The Anschutz Corporation are engaged principally in telecommunications and media, natural resources, transportation, real estate, farming and ranching, and sports and entertainment. He has been the non-executive Chairman of the Board of Directors of Regal Entertainment Group since May 2002 and a director of Qwest Communications International, Inc. since February 1997. He has been Non-Executive Vice Chairman of Union Pacific Corporation since 1996.

Clifford P. Hickey was elected to the Board of Directors in March 2002. He has served as Managing Director of Anschutz Investment Company since June 2002. From July 1999 to May 2002 he served as Vice President of Anschutz Investment Company. From July 1998 to June 1999 he served as a Director in the Energy Group of Prudential Securities.

David L. Lemmon was elected to the Board of Directors in April 2002. Mr. Lemmon has served as President and Chief Executive Officer of Colonial Pipeline Company since November 1997 and as a director from 1990 to November 1997. He served as President of Amoco Pipeline Company from 1990 to 1997, as Manager for Corporate Planning for Amoco Corporation from 1989 to 1990 and Vice President and General Manager Operations for Amoco Pipeline Company from 1987 to 1989. Mr. Lemmon joined Amoco in 1965.

Jim E. Shamas was elected to the Board of Directors in December 2001. He served as a director of Pacific Energy Group LLC from August 2001 to March 2002 and as a representative on the Pacific Pipeline System LLC Members Committee from May 1999 to April 2002. From September 1994 until his retirement in December 1998, Mr. Shamas was President of Rooney Engineering, Inc. and Interwest Group, Inc. Mr. Shamas has served as a director of Rooney Engineering, Inc. since September 1994. Prior to that, he served as President and Chief Executive Officer of Texaco Trading and Transportation Inc. from August 1984 to August 1994. From May 1982 until August 1984, Mr. Shamas served as President and Chief Executive Officer of Getty Trading and Transportation and Vice President of Getty Oil Company.

Irvin Toole, Jr. was elected President, Chief Executive Officer and director in December 2001. He has been President, Chief Executive Officer and director of Pacific Energy Group LLC since August 2001 and has been President and Chief Executive Officer of Pacific Pipeline System LLC since July 1999 and served as a representative to its Members Committee from July 1999 to April 2002. Mr. Toole served as President and Chief Executive Officer of the predecessor of Pacific Pipeline System LLC in June 1998 after having served as Chairman, President and Chief Executive Officer of Santa Fe Pacific Pipelines, Inc., the general partner of Santa Fe Pacific Pipeline Partners, L.P., from September 1991 to April 1998.

David E. Wright was elected Executive Vice President, Corporate Development and Marketing in December 2001 and served as director of Pacific Energy GP, Inc. from December 2001 to June 2002. He has been Executive Vice President, Corporate Development and Marketing and director of Pacific Energy Group LLC since August 2001 and Executive Vice President Corporate Development and Marketing of Pacific Pipeline System LLC since June 2001. Mr. Wright joined Pacific Energy Group LLC in June 2001 after having served as Vice President, Distribution West of Tosco Refining Company from March 1997 to June 2001. From October 1995 to March 1997, Mr. Wright served as Vice President, Pipelines for GATX Terminals Corporation.

Gerald A. Tywoniuk was elected Senior Vice President, Chief Financial Officer and Treasurer in December 2002. Previously, he was Senior Vice President, Chief Financial Officer and a member of the Board of Directors of the general partner of MarkWest Energy Partners, L.P. from its initial public offering in May 2002 to November 2002. He also served as Senior Vice President and Chief Financial Officer with MarkWest Hydrocarbon, Inc. from December 2001, and as a director from March 2002, to November 2002. Prior to that, Mr. Tywoniuk was MarkWest Hydrocarbon's Vice President of Finance and Chief Financial Officer since April 1997.

Lynn T. Wood was elected Vice President, General Counsel and Secretary in March 2002. He has been Vice President of Pacific Energy Group LLC since August 2001, Vice President of Pacific Pipeline System LLC and its predecessor since October 1998 and Secretary since October 1996. Mr. Wood was the Secretary and Assistant General Counsel of Anschutz Company and The Anschutz Corporation from October 1996 to October 2002, during which time he had the responsibility for providing ongoing legal services to Pacific Pipeline System LLC and, after their formation, Pacific Energy Group LLC and the Partnership.

Lyle B. Boarts was elected Vice President, Human Resources in January 2004. Before joining Pacific Energy GP, Inc., he was Vice President, Human Resources, GTran Inc. since March 2000 and was Vice President, Human Resources with Ortel Corporation from March 1998. Mr. Boarts also served as Vice President, Human Resources with Santa Fe Pacific Pipelines, Inc., general partner of Santa Fe Pacific Pipeline Partners, L.P., from June 1986 to March 1998.

Arthur G. Diefenbach was elected Vice President, Operations and Technical Services West Coast in March 2002. He has been Vice President, Operations & Technical Services of Pacific Energy Group LLC since August 2001 and Vice President, Operations & Technical Services of Pacific Pipeline Systems LLC since July 1999. Mr. Diefenbach joined Pacific Energy Group LLC in July 1999 after having served as Manager, Western Region of ARCO Pipeline Company from August 1998 to July 1999 and as Superintendent, Operations of ARCO Pipeline Company from January 1990 to August 1998.

Jesse G. Metcalf was elected Vice President, Operations and Technical Services Rocky Mountains in March 2002. From 2000 to March 2002, Mr. Metcalf served as Vice President, Anschutz Ranch East Pipeline, Anschutz Marketing and Transportation and Anschutz Wahsatch Gathering System. Prior to that, he served as Manager, Operations from 1987 to 2000. From 1982 to 1987, Mr. Metcalf served as Field Supervisor, Exploration and Production for The Anschutz Corporation.

John Tsouvalas was elected Vice President, Marketing and Business Development West Coast in October 2003. He has been the Director, Marketing and Business Development for Pacific Energy Group LLC's West Coast Operations since August 2001 and Director of Marketing and

Business Development of Pacific Pipeline System LLC since July 1999. Mr. Tsouvalas joined Pacific Energy Group LLC in July 1999 after having served as West Coast Crude Asset Manager for ARCO Pipe Line Company from January 1996 to July 1999 and as Marketing and Scheduling Manager of ARCO Pipe Line Company West Coast from January 1990 to January 1996.

Gary L. Zollinger was elected Vice President, Marketing and Business Development Rocky Mountains in March 2002. Mr. Zollinger joined Pacific Energy Group LLC in January 2002 after having served as President of Crossing Associates LLC from 2001 to January 2002. From 1998 to 2001, he served as Vice President of North American Consulting Group LLC. Crossing Associates LLC and North American Consulting Group LLC are privately held consulting firms specializing in the mid-stream energy business. From 1997 to 1998 Mr. Zollinger did private consulting work in the mid-stream energy business.

Harsha M. Tank was elected Controller in April 2003. She joined Pacific Energy GP, Inc. as Manager, Internal Audit and Performance Analysis in September 2002. Prior to joining Pacific Energy GP, Inc., Ms. Tank served as Controller for James Hardie Building Products, Inc. in 2002 and as Regional Controller for Qwest Digital Media LLC from 2000 to 2002. Ms. Tank also served as Regional Controller for Mail-Well, Inc. for their Southwest Region from 1996 to 2000.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, requires directors, officers and persons who beneficially own 10% or more of a class of our equity securities that is registered under Section 12 of the Exchange Act to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such securities. These persons are also required to furnish us copies of all Section 16(a) reports they filed. Based solely upon a review of the copies of reports on Forms 3, 4 and 5 furnished to us, or written representations that no reports on Form 5 were required, we believe the directors and officers of our General Partner, and our General Partner in its capacity as a beneficial owner complied with all filing requirements with respect to transactions in our equity securities in 2003.

Audit Committee Financial Expert

The board of directors of our General Partner has determined that David L. Lemmon, a member of the audit committee, is an "audit committee financial expert," as that term is defined under the Securities Act and the Exchange Act, and that Mr. Lemmon is "independent," as that term is used in the Exchange Act.

Code of Ethics

Our General Partner has adopted a code of ethics that applies to all employees, including its principal executive officers, principal financial officer, principal accounting officer and its Board of Directors. A copy of the code of ethics is available on our Internet website at www.PacificEnergyPartners.com. Our General Partner intends to satisfy the disclosure requirement under Item 10 of the current report on Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics by posting such information on our website at the Internet website address set forth above.

Reimbursement of Expenses of the General Partner

Our General Partner does not receive any management fee or other compensation for its management of the Partnership. However, our General Partner and its affiliates are reimbursed for all expenses incurred by them on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us and all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our General Partner may determine the expenses that are allocable to us in any reasonable manner determined by our General Partner in its sole discretion.

ITEM 11. Executive Compensation

We and our General Partner were formed in 2002. Accordingly, our General Partner paid no compensation to its directors and officers with respect to the 2001 fiscal year. We have not accrued obligations with respect to management incentives or benefits for the directors and officers with respect to the 2001 fiscal year. Officers and employees of our General Partner may participate in employee benefit plans and arrangements sponsored by our General Partner, including plans that may be established by the General Partner in the future.

The following table sets forth certain information at December 31, 2003 and 2002 and for the fiscal years then ended with respect to compensation of our General Partner's chief executive officer and certain other executive officers.

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long-term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary	Bonus	Other Annual Compensation(4)	Restricted Unit Grants(5)	Unit Option Grants	LTIP Payouts(6)	All Other Compensation(7)
Douglas L. Polson(1) Chairman of the Board of Directors	2003	$ 280,000	$ 112,042	$	$		$ 1,962,000	$ 24,033
	2002	243,883	200,760			50,000		22,823
Irvin Toole, Jr. President, Chief Executive Officer and Director	2003	260,000	104,657				678,500	12,050
	2002	260,000	191,158					12,305
David E. Wright Executive Vice President, Corporate Development and Marketing	2003	206,500	57,903				203,625	5,679
	2002	204,875	122,585					6,306
Gerald A. Tywoniuk(2) Senior Vice President, Chief Financial Officer and Treasurer	2003	200,000	44,725	88,171			54,300	9,000
	2002	16,667	6,639					51,000
Lynn T. Wood(3) Vice President, General Counsel and Secretary	2003	170,000	35,721	167,322			135,750	8,075
	2002	156,278	62,864					13,379

(1) Prior to October 1, 2002, Douglas L. Polson was employed by Anschutz and acted as an executive officer of our General Partner. The salary and other compensation amounts shown include $194,748 and $20,400, respectively, paid by Anschutz to Mr. Polson for time spent on Partnership related matters, which is estimated at 85% of Mr. Polson's services for the period of January 1 through October 1, 2002.

(2) Gerald A. Tywoniuk became an employee of our General Partner on Dec. 2, 2002.

(3) Prior to September 16, 2002, Lynn T. Wood was employed by Anschutz and acted as an executive officer of our General Partner. The salary and other compensation amounts shown include $107,348 and $10,157, respectively, paid by Anschutz to Mr. Wood for time spent on Partnership related matters.

(4) Includes for Mr. Tywoniuk and Mr. Wood reimbursement of relocation expenses, including reimbursement of associated income taxes of $33,027 and $64,612, respectively.

(5) Amounts reported in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2002 as restricted stock grants are now shown in the Long-Term Incentive Plan table below.

(6) Calculated as follows: common units issued upon vesting (pursuant to the Partnership's Long-Term Incentive Plan), multiplied by the closing market price on the day prior to issuance.

(7) Reflects employer contribution to the General Partner's 401(k) plan and in the case of Mr. Tywoniuk, a one-time payment of $50,000 in 2002 upon commencement of employment with our General Partner.

Unit Option Awards

No common unit options were granted during 2003.

Long-Term Incentive Plan Awards

The following table sets forth certain information at December 31, 2003 and for the fiscal year then ended with respect to common units which were awarded during 2003 to the individuals named in the Summary Compensation Table above. Information with respect to 2002 is also being reported since it was previously reported in the Summary Compensation Table above. Vesting of common units occurs over the indicated periods.

LONG-TERM INCENTIVE PLANS AWARDS IN LAST FISCAL YEAR (2003)

			Estimated Future Payouts under Non-Unit Price-Based Plans
Name	**Number of Units**	**Performance or Other Period until Maturation or Payment**	**Maximum Number (units)**
Gerald A. Tywoniuk	15,000	(1)	15,000

(1) 2,000 units vest in each of 2003 through 2006 inclusive and 7,000 units vest in 2007.

LONG-TERM INCENTIVE PLANS AWARDS IN 2002

			Estimated Future Payouts under Non-Unit Price-Based Plans
Name	**Number of Units**	**Performance or Other Period until Maturation or Payment**	**Maximum Number (units)**
Douglas L. Polson	150,000	(1)	150,000
Irvin Toole, Jr.	75,000	(2)	75,000
David E. Wright.	37,500	(3)	37,500
Gerald A. Tywoniuk.			
Lynn T. Wood.	25,000	(3)	25,000

(1) 75,000 units vest each year in 2003 and 2004.

(2) 25,000 units vest each year beginning in 2003 and ending in 2005.

(3) 20% of the units vest each year beginning in 2003 and ending in 2007.

For a discussion of our General Partner's long-term incentive plan, please read "Long-Term Incentive Plan" below.

Committees, Meetings and Director Compensation

Our General Partner's Board of Directors has the responsibility for establishing broad policies and for our overall direction and management. Our General Partner's Board of Directors held five meetings during 2003. Each director attended all of the Board meetings held during 2003. The Board has established standing committees to consider designated matters. The standing committees of the Board are Audit, Compensation, Conflicts, and Nominating and Governance.

Audit Committee

The members of the Audit Committee are: David L. Lemmon, Chairman and Jim E. Shamas. Robert F. Starzel served on the Audit Committee until his resignation from the Board of Directors on February 25, 2004. The Board of Directors is currently in the process of finding a replacement for Mr. Starzel. The members of the Audit Committee are not officers or employees of our General Partner. Among other things, the Audit Committee is responsible for reviewing our external financial reporting, including reports filed with the SEC, engaging and reviewing our independent auditors, and reviewing procedures for internal auditing and the adequacy of our internal accounting controls. The Committee held five meetings during 2003, and all members of the Committee attended each such meeting.

Compensation Committee

The members of the Compensation Committee are: Jim E. Shamas, Chairman and David L. Lemmon. Robert F. Starzel served on the Compensation Committee until his resignation from the Board of Directors on February 25, 2004. The Compensation Committee is responsible for overseeing compensation related decisions for the officers and directors of our General Partner. The Committee held two meetings during 2003, and all members of the Committee attended each such meeting.

Conflicts Committee

The members of the Conflicts Committee are: Jim E. Shamas, Chairman, and David L. Lemmon. The Conflicts Committee is responsible for reviewing specific matters, including those that the Board of Directors believes may involve conflicts of interest between our General Partner or its affiliates and the Partnership. The General Partner is authorized, but not required, to seek approval of the Conflicts Committee whether the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not officers or employees of our General Partner or its affiliates. The Committee held two meetings during 2003, which were attended by both members of the Committee.

Nominating and Governance Committee

The members of the Nominating and Governance Committee are: Douglas L. Polson, David L. Lemmon and Jim E. Shamas. Robert F. Starzel served as Chairman of the Nominating and Governance Committee until his resignation from the Board of Directors on February 25, 2004. The Nominating and Governance Committee is responsible for assisting the Board of Directors in identifying individuals qualified to become Board members, recommending nominees to Board committees, formulating and recommending guidelines for corporate governance, and leading the Board in its annual review of the Board's performance. The Committee held two meetings in 2003, which were attended by all members.

Compensation of Directors

Beginning May 2003, our General Partner increased the annual rate of compensation for outside directors to $40,000, which covers attendance at meetings of the Board of Directors as well as committee meetings and serving as committee chairman. The previous annual compensation was $30,000. Our General Partner pays no director's fee to directors who are also officers or employees of Anschutz or our General Partner. In 2003, outside directors also each received a grant of 3,000 restricted units under our long-term incentive plan, which vests over three years. In addition, each director is reimbursed for his out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Employment Agreements

Douglas L. Polson

Mr. Polson entered into an employment agreement with our General Partner effective on October 1, 2002. The employment agreement may be terminated by either Mr. Polson or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Polson is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Chairman of the Board of Directors.

Under his employment agreement, our General Partner may terminate Mr. Polson's employment for cause or without cause. If Mr. Polson's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment as well as continuation of certain benefits for up to two years. If Mr. Polson is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase.

Mr. Polson's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Irvin Toole, Jr.

Mr. Toole entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Toole or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Toole is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as President and Chief Executive Officer and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Toole's employment for cause or without cause. If Mr. Toole's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment as well as continuation of certain benefits for up to two years. If Mr. Toole is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase.

Mr. Toole's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

David E. Wright

Mr. Wright entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Wright or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Wright is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Executive Vice President, Corporate Development and Marketing and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Wright's employment for cause or without cause. If Mr. Wright's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Wright is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to two years and he will be entitled to receive six months of executive outplacement services.

Mr. Wright's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Gerald A. Tywoniuk

Mr. Tywoniuk entered into an employment agreement with our General Partner effective on November 1, 2002. The employment agreement may be terminated by either Mr. Tywoniuk or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Tywoniuk is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Chief Financial Officer and will be provided with a vehicle. Upon commencement of his employment, Mr. Tywoniuk received a one-time payment.

Under his employment agreement, our General Partner may terminate Mr. Tywoniuk's employment for cause or without cause. If Mr. Tywoniuk's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Tywoniuk is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Tywoniuk's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Lynn T. Wood

Mr. Wood entered into an employment agreement with our General Partner effective on September 5, 2002. The employment agreement may be terminated by either Mr. Wood or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Wood is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Vice President, General Counsel and Secretary and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Wood's employment for cause or without cause. If Mr. Wood's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Wood is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Wood's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Gary L. Zollinger

Mr. Zollinger entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Zollinger or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Zollinger is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Vice President, Marketing and Business Development Rocky Mountain Operations.

Under his employment agreement, our General Partner may terminate Mr. Zollinger's employment for cause or without cause. If Mr. Zollinger's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Zollinger is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Zollinger's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Long-Term Incentive Plan

General

Our General Partner has adopted a long-term incentive plan for employees and directors of the General Partner and employees of its affiliates who perform services for us.

The plan consists of two components: restricted units and unit options. The aggregate number of units permitted to be granted under the long-term incentive plan is 1,750,000. The long-term incentive plan is administered by the compensation committee of our General Partner's Board of Directors, subject to the approval of compensation committee recommendations by the Board of Directors. Grant levels, the type of award and the frequency of grants for designated employees will be recommended by the chairman and by the chief executive officer of our General Partner, subject to the review and approval of the compensation committee. The compensation committee will determine the grant level, the type of award and the frequency of grants for directors. Our General Partner's Board of Directors may terminate or amend the plan at any time with respect to units for which a grant has not yet been made. However, no change may be made that would materially impair the rights of a participant with respect to an outstanding grant without the consent of the participant.

Upon vesting of restricted units or the exercise of unit options, the Partnership has the option of paying the holder of the restricted units or the options in cash equal to the fair market value, by issuing common units acquired by our General Partner in the open market, common units already owned by our General Partner, common units acquired by our General Partner directly from us or any other person, new common units issued by us, or any combination of the foregoing. We intend to deliver common units rather than pay cash, as restricted units vest. Our General Partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, or the exercise of a unit option, the total number of common units outstanding will increase.

Restricted Units

A restricted unit is a "phantom" unit. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. In 2002, we granted 381,250 restricted units of which 12,500 were subsequently forfeited. In 2003, our General Partner granted 25,000 and 9,000 restricted units to its employees and three outside directors, respectively. Of the units granted in 2003, 3,000 units were subsequently forfeited. In January 2004, our General Partner granted an additional 7,500 restricted units to an employee. In the future, the compensation committee may determine to make additional grants under the plan to employees and directors containing such terms as the compensation committee shall determine under the plan. The compensation committee will determine the period over which restricted units granted to employees and directors will vest. The committee may base its determination upon the achievement of specified financial objectives. If a grantee's employment or membership on the Board of Directors terminates for any reason other than death, disability or upon the occurrence of certain other specified events that cause immediate full vesting, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. In addition, the restricted units will vest upon a change of control of Pacific Energy Partners or our General Partner. The compensation committee, in its discretion, may grant tandem distribution equivalent rights, i.e. the right to receive cash equal to cash distributions made on a common unit, with respect to restricted units; however, none have been granted.

We intend the issuance of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for such units.

In July 2003, 75,000 of the restricted units granted to an employee of our General Partner vested with 51,690 of those restricted units converted to common units and 23,310 of those restricted units surrendered to the Partnership to satisfy tax withholding obligations upon vesting. In December 2003, 55,750 of the restricted units granted to employees of our General Partner vested with 40,073 of those restricted units converted to common units and 15,677 of those restricted units surrendered to the Partnership to satisfy tax withholding obligations upon vesting. Certain individuals satisfied their withholding tax obligations through the payment of cash to our General Partner.

Unit Options

The compensation committee may determine to grant unit options under the plan to employees and directors containing such terms as the committee shall determine. Unit options will have an exercise price that may not be less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, the unit options will become exercisable upon a change in control of Pacific Energy Partners or our General Partner. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders. No unit options were granted in 2003. In December 2002, we granted 50,000 unit options.

Annual Incentive Plan

Our General Partner has an annual incentive compensation plan that is designed to enhance the performance of eligible employees of our General Partner by rewarding them with cash awards for certain individual achievements and the Partnership achieving certain annual financial and operational performance objectives. The compensation committee may in its discretion determine individual participants and payments, if any, for each fiscal year. The Board of Directors of our General Partner may amend or change the annual incentive plan at any time. We will reimburse our General Partner for payments and costs incurred under the plan.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of units of Pacific Energy Partners as of February 28, 2004, held by beneficial owners of more than 5% of the units, by directors of our General Partner, by each named executive officer and by all directors and executive officers of our General Partner as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units	Subordinated Units Beneficially	Percentage of Subordinated Units	Percentage of Total Units Beneficially	Restricted Units(4)

		Beneficially Owned(3)	Owned	Beneficially Owned	Owned(3)	
The Anschutz Corporation(1)			10,465,000	100%	42.0%	
Pacific Energy GP, Inc.(1)(2)					*	
Douglas L. Polson	52,690	*			*	75,000
Philip F. Anschutz(1)	1	*	10,465,000	100%	42.0%	
Clifford P. Hickey	2,000	*			*	
David L. Lemmon	100	*			*	3,000
Jim E. Shamas	1,000	*			*	3,000
Irvin Toole, Jr.	22,062	*			*	50,000
David E. Wright	9,300	*			*	30,000
Gerald A. Tywoniuk	3,787	*			*	13,000
Lynn T. Wood	4,212	*			*	20,000
All directors and executive officers as a group (16 persons)	108,587	0.8%	10,465,000	100%	42.0%	266,500

(1) The subordinated units previously owned by Pacific Energy GP, Inc., are now owned by The Anschutz Corporation. The Anschutz Corporation is a wholly owned subsidiary of Anschutz Company, which is entirely owned by Mr. Philip F. Anschutz. In addition, Mr. Anschutz owns one common unit in us. Pacific Energy GP, Inc., an indirect wholly-owned subsidiary of The Anschutz Corporation, owns no common or subordinated units; however, it holds a 2% general partner interest and incentive distribution rights in us.

(2) The address of Pacific Energy GP, Inc. is 5900 Cherry Avenue, Long Beach, California, 90805-4408.

(3) In each instance a "*" indicates that the individual owns less than 0.1% of the common and total units outstanding.

(4) A restricted unit is a "phantom" unit which entitles the grantee to receive a common unit upon vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. At the date of each grant, the compensation committee determines the period over which restricted units granted to employees and directors will vest and may base its determination upon the achievement of specified financial objectives. The amounts shown in the table above have not vested. If a grantee's employment or membership on the Board of Directors terminates for any reason other than death, disability or upon the occurrence of certain other specified events that cause immediate full vesting, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. In addition, the restricted units will vest upon a change of control of Pacific Energy Partners or our General Partner. Please read "Item 11 Long-Term Incentive Plan Restricted Units" above.

Equity Compensation Plan Information

The following table sets forth certain information at January 31, 2004 with respect to the number of units issuable under our equity compensation plans:

Plan Category	(a) Number Of Securities to be Issued Upon Exercise of Outstanding Options	(b) Weighted Average Exercise Price of Outstanding Options	(c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (excluding in column a) securities reflected
Equity Compensation Plans Approved By Unitholders			
Equity Compensation Plans Not Approved By Unitholders	50,000	$ 19.50	1,289,750

ITEM 13. Certain Relationships and Related Transactions

Distributions and Payments to the General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with the formation, ongoing operation and any liquidation of Pacific Energy Partners. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage
(July 26, 2002)

The consideration received by our General Partner and its affiliates for the contribution of assets and liabilities to us	1,865,000 common units(1);
	10,465,000 subordinated units (2);
	2% general partner interest in Pacific Energy Partners;
	the incentive distribution rights; and
	$105.1 million from the proceeds of the term loan.

(1) The 1,865,000 common units received by our General Partner were subsequently disposed of in the following transactions:

On August 25, 2003, we issued and sold 5,000,000 common units in an underwritten public offering at a price of $24.66 per common unit before underwriting fees and offering expenses. In addition, we granted the underwriters an option to purchase up to an additional 750,000 common units to cover over-allotments, if any. We used a portion of the net proceeds from this offering to redeem 1,115,000 common units owned by our General Partner for $26.3 million, or $23.612 per common unit, which is equal to the net proceeds per common unit we received in the offering, before offering expenses. Following redemption, the 1,115,000 redeemed common units were cancelled.

On August 29, 2003 and September 3, 2003, the underwriters exercised a portion of the over-allotment option and purchased an additional 500,000 common units and 112,100 common units, respectively, from us at a price of $24.66 per common unit to cover over-allotments before underwriting fees and offering expenses. The net proceeds were used to redeem 612,100 common units owned by our General Partner for $14.5 million, or $23.612 per common unit, which is equal to the net proceeds per common unit we received in the offering, before offering expenses. Following redemption, the 612,100 redeemed common units were cancelled.

On November 19, 2003 our General Partner sold its remaining 137,900 common units to unrelated third parties.

(2) On November 25, 2003, our General Partner transferred all of its subordinated units to Anschutz.

Operational Stage
(Subsequent to July 26, 2002)

Distributions of available cash to our General Partner	We will generally make cash distributions 98% to the unitholders, including Anschutz as holder of all of the subordinated units, and 2% to our General Partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner, as the holder of the incentive distribution rights, will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level.
	Assuming we have sufficient available cash to pay

	the full minimum quarterly distribution on all of our outstanding units for four quarters, our General Partner would receive aggregate distributions for the four quarters of approximately $0.9 million on the General Partner's 2% general partner interest and Anschutz would receive approximately $19.4 million on its subordinated units.
Reimbursements to our General Partner and its affiliates	Our General Partner will be entitled to reimbursement for all expenses it incurs on our behalf, including salaries and employee benefit costs for its employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our General Partner in connection with operating our business. Our General Partner has sole discretion in determining the amount of these expenses.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Omnibus Agreement

In connection with the completion of our initial public offering in July 2002, we entered into an omnibus agreement with Anschutz and our General Partner that addresses the following matters:

- Anschutz's and its affiliates' agreement not to compete with us under certain circumstances; and
- an indemnity by Anschutz for certain environmental liabilities and income tax liabilities.

Noncompetition

Anschutz agreed, and caused its affiliates to agree, for so long as Anschutz controls our General Partner, not to engage in, whether by acquisition or otherwise, the business of transportation of crude oil by pipeline in the United States for any third parties or crude oil storage and terminalling activities in the United States for any third parties. This restriction does not apply to:

- any other businesses of Anschutz or its subsidiaries, including without limitation gathering or marketing activities;
- any activities performed by Anschutz or its subsidiaries primarily in connection with oil and gas properties owned jointly by Anschutz or its subsidiaries with other parties;
- the business activities of certain public and private companies in which Anschutz or its subsidiaries hold an ownership interest;

any business owned by Anschutz or its subsidiaries on July 26, 2002, the completion date of our initial public offering, including any capital improvements, replacements or direct expansions of these businesses;

any business that Anschutz or any of its subsidiaries acquires or constructs that has a fair market value of less than $10.0 million for any particular transaction and less than $50.0 million on an aggregate basis within the preceding 12-month period;

any business that Anschutz or any of its subsidiaries acquires or constructs that has a fair market value of $10.0 million or greater for any particular transaction or $50.0 million or greater on an aggregate basis within the preceding 12-month period, in each case if we have been offered the opportunity to purchase the business for fair market value and we decline to do so with the approval of our conflicts committee; and

any business that Anschutz or any of its subsidiaries acquires or constructs if we have agreed with Anschutz or any of its subsidiaries in advance, with the approval of our conflicts committee, on the amount and nature of consideration, closing date and other terms upon which we will

acquire the business from Anschutz or its subsidiaries after the acquisition or construction of the business by Anschutz or its subsidiaries.

In addition, the limitations on the ability of Anschutz and its affiliates to compete with us may terminate upon a change of control of Anschutz.

Indemnification

Pursuant to the omnibus agreement, Anschutz agreed to indemnify us for three years following the completion of our initial public offering against unknown environmental liabilities associated with the operation of the assets contributed to us by Anschutz and occurring before July 26, 2002. This indemnity is limited to a maximum of $10.0 million and is subject to a $1.0 million aggregate deductible.

Anschutz also agreed to indemnify us for certain income tax liabilities attributable to the operation of the assets contributed to us prior to the time that they were contributed.

Other Related Party Transactions

In the ordinary course of our operations, we engage in various transactions with Anschutz and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the year ended December 31, 2003, 2002 and 2001:

	For the Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Pipeline transportation revenue:			
Anschutz and affiliates	$ 1,120	$ 2,682	$
Operating expenses:			
Anschutz and affiliates		496	419
General and administrative expense:			
Anschutz and affiliates	169	205	166

Related party balances at December 31, 2003 and 2002 are reflected on the consolidated balance sheets included in the section entitled "Item 8 Financial Statements and Supplementary Data" as follows:

	December 31, 2003	December 31, 2002

	December 31, 2003	December 31, 2002
	(in thousands)	
Amounts included in accounts receivable:		
Anschutz and affiliates	$ 155	$ 521
Amounts included in due to related parties:		
Anschutz and affiliates	$	$ 672
Pacific Energy GP, Inc.	580	280
Total	$ 580	$ 952
Amounts included in undistributed long-term incentive compensation:		
Pacific Energy GP, Inc.	$ 738	$ 72

Revenue from Related Parties

A subsidiary of Anschutz was a shipper on Line 2000 and was charged the published tariff rates applicable to "participating shippers" until March 31, 2003, when an agreement between the Anschutz subsidiary and a third party, the performance of which required the Anschutz subsidiary to ship on Line 2000, was assigned to PMT for consideration equal to the value of inventory that was transferred to PMT. In addition, a subsidiary of Anschutz is a shipper on RMPS's pipeline systems and the AREPI pipeline and is charged published tariff rates.

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

Expenses Paid to Related Parties

Operating Expense. 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.

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

In 2002, Anschutz provided office space to several of our employees at no cost to us. Beginning January 2003, we 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.

Cost Reimbursements. We have no employees. Our General Partner, which is a wholly owned indirect subsidiary of Anschutz, employed approximately 260 individuals at December 31, 2003 who directly supported our operations. All expenses incurred by our General Partner on our behalf are charged to us.

The operating and general and administrative cost reimbursement amounts above exclude reimbursements for property, casualty and directors and officers insurance premiums paid by Anschutz on our behalf. We reimbursed insurance costs of $2.0 million in 2002. Reimbursement for insurance costs was minimal in 2003 and 2001. Beginning with the 2003-2004 insurance policy period, we incurred these costs directly. In addition, we reimbursed Anschutz for out-of-pocket costs incurred by Anschutz for our benefit for computer consultants and surety bonds.

Prior to our initial public offering in July 2002, Anschutz was providing letters of credit for PMT activities. PMT reimbursed Anschutz for its cost of providing these letters of credit. Following our 2002 initial public offering, such letters of credit were replaced by letters of credit under our $200.0 million revolving credit facility.

Transactions Related to Partners' Capital

On July 23, 2003 and December 16, 2003, to satisfy vesting requirements under the terms of our General Partner's Long-Term Incentive Plan, the General Partner acquired from us 51,690 and 40,073 newly issued common units respectively, for delivery to plan participants.

Subsequent to our 2002 initial public offering, cash distributions paid to our General Partner, an indirect wholly owned subsidiary of Anschutz, on its common units, subordinated units and 2% general partner interest in us for 2003 and 2002 were $23.1 million and $4.3 million, respectively.

During 2002, prior to the initial public offering in July 2002, PEG received a capital contribution from Anschutz of $8.8 million and paid distributions to Anschutz of $16.0 million. Concurrent with the initial public offering, PEG paid a distribution of $105.1 million to Anschutz. On December 31, 2001, AREPI declared and effected dividends to Anschutz of $2.9 million. These dividends represented the amount of receivables due from Anschutz and its subsidiaries immediately prior to the payment of the dividends.

Other Matters

ARCO owned a 26.5% ownership interest in PPS from May 1, 1999 through June 7, 2001 and was therefore a related party of ours during this period. During this period, PPS entered into various agreements with ARCO under which ARCO provided operating services to us and leased facility space from us. We also shared with ARCO certain facilities that supported our operations and ARCO's operations. The cost of operating the shared facilities was allocated based on the percentage benefit obtained by both parties. We paid ARCO $0.2 million and received $0.2 million during 2001.

ITEM 14. Principal Accountant Fees and Services

The following table presents fees for professional audit services rendered by KPMG LLP for the audit of our annual financial statements for the years ended December 31, 2003 and 2002 and fees billed for other services rendered by KPMG during those periods.

For the Year Ended December 31,	2003	2002(2)
	(in thousands)	
Audit fees	$ 215	$ 195
Audit related fees(1)	210	725
Tax fees		
All other fees		
Total	$ 425	$ 920

(1) Audit related fees consist of assurance and related services that are reasonably related to the performance of the audit or review of our financial statements. This category includes fees related to the review of our quarterly and other SEC filings and accounting consultations regarding the application of GAAP to proposed transactions.

(2) Includes the period prior to our initial public offering in July 2002.

The Audit Committee reviewed and approved, in advance, audit and non-audit services provided by KPMG LLP.

Part IV

ITEM 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a)(1) and (2) Financial Statements and Financial Statement Schedules

Please see "Index to Consolidated Financial Statements" on page F-1.

(a)(3) Exhibits

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

Exhibit Number	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated July 26, 2002 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 3.2)
3.2	Second Amended and Restated Limited Liability Company Agreement of Pacific Energy Group LLC, dated July 26, 2002 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 3.7)
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated August 1, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 3.3)
*3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated January 27, 2004.
4.1	Form of Indenture of Pacific Energy Partners, L.P. (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 4.1)
4.2	Form of Indenture of Pacific Energy Group LLC (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 4.2)
10.1	Credit Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.1)
*10.2	Amendment No. 1 to Credit Agreement, dated July 18, 2003
*10.3	Amendment No. 2 to Credit Agreement, dated December 12, 2003
10.4	Contribution and Conveyance Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.3)
10.5	Employment Agreement between Pacific Energy GP, Inc. and Irvin Toole, Jr. (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-1 filed on July 19, 2002, Exhibit 10.4)
10.6	Employment Agreement between Pacific Energy GP, Inc. and David E. Wright (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1 filed on July 2, 2002, Exhibit 10.5)
10.7	Employment Agreement between Pacific Energy GP, Inc. and Gary L. Zollinger (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1 filed on July 2, 2002, Exhibit 10.6)
10.8	Omnibus Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.10)

10.9	Form of Pacific Energy GP, Inc. Long-Term Incentive Plan (incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1 filed on July 19, 2002, Exhibit 10.8(b))
10.10	Employment Agreement between Pacific Energy GP, Inc. and Douglas L. Polson (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.12)
10.11	Employment Agreement between Pacific Energy GP, Inc. and Gerald A. Tywoniuk (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.13)
10.12	Employment Agreement between Pacific Energy GP, Inc. and Lynn T. Wood (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.14)
10.13	Form of Pacific Energy GP, Inc. Annual Incentive Plan (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1 filed on July 19, 2002, Exhibit 10.8(b))
*21.1	List of Subsidiaries of Pacific Energy Partners, L.P.
*23.1	Consent of KPMG LLP
*31.1	Certification of Principal Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
*31.2	Certification of Principal Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1	Certification of Chief Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
32.2	Certification of Chief Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

* Filed herewith.

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

(b) Reports on Form 8-K:

Date of Event Reported	Item(s) Reported	Description
October 29, 2003	7, 9 & 12	Filed in connection with the Partnership's third quarter 2003 earnings release on October 29, 2003.
November 20, 2003	7 & 9	Filed in connection with the Partnership's press release on November 20, 2003 commenting on the announced Shell Oil Co. refinery closure in Bakersfield, California.
January 28, 2004	7, 9 & 12	Filed in connection with the Partnership's fourth quarter 2003 earnings release on January 27, 2004.
March 2, 2004	7 & 9	Filed in connection with the Partnership's press release on February 24, 2004 announcing Pacific Energy Partners, L.P. agreements to purchase Canadian pipelines.
March 12, 2004	9 & 12	Filed in connection with the Partnership's press release on March 10,

Date of Event Reported	Item(s) Reported	Description
		2004 announcing adjustment to 2003 net income.

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

March 12, 2004

By: /s/ IRVIN TOOLE, JR.

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

March 12, 2004

By: /s/ GERALD A. TYWONIUK

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

Pursuant to the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons in the capacities and on the dates indicated.

Date	Signature	Title
March 12, 2004	/s/ DOUGLAS L. POLSON Douglas L. Polson	Chairman of the Board of Directors
March 12, 2004	/s/ PHILIP F. ANSCHUTZ Philip F. Anschutz	Director
March 12, 2004	/s/ CLIFFORD P. HICKEY Clifford P. Hickey	Director
March 12, 2004	/s/ DAVID L. LEMMON David L. Lemmon	Director
March 12, 2004	/s/ JIM E. SHAMAS Jim E. Shamas	Director

INDEX TO FINANCIAL STATEMENTS

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

The Board of Directors of the General Partner and Unitholders of
Pacific Energy Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Pacific Energy Partners, L.P. and subsidiaries, as of December 31, 2003 and 2002, and the related consolidated statements of income, partners' capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of Pacific Energy Partners, L.P.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pacific Energy Partners, L.P. and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ KPMG LLP

KPMG LLP

Los Angeles, California
January 26, 2004, except note 15,
which is as of February 24, 2004

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

Successor to Pacific Energy (Predecessor)

CONSOLIDATED BALANCE SHEETS

December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,699	$ 23,873
Crude oil sales receivable	33,766	24,157
Transportation and storage accounts receivable	16,828	10,568
Crude oil inventory (note 1)	2,272	3,887
Spare parts inventory	1,644	445
Prepaid expenses	4,182	2,720
Other	405	421
Total current assets	68,796	66,071
Property and equipment, net (note 3)	567,954	404,842
Investment in Frontier (note 4)	6,886	9,175
Other assets	6,567	6,950
	$ 650,203	$ 487,038
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 11,506	$ 10,965
Accrued crude oil purchases	31,602	24,385
Due to related parties (note 8)	580	952
Derivatives liability current portion (note 1)	4,986	4,775
Other	1,317	494
Total current liabilities	49,991	41,571
Long-term debt (note 7)	298,000	225,000
Derivatives liability (note 1)	622	2,600
Other liabilities (note 14)	6,523	2,600
Total liabilities	355,136	271,771
Commitments and contingencies (note 14)		
Partners' capital (note 6):		
Common unitholders (14,441,763 and 10,465,000 units outstanding at December 31, 2003 and December 31, 2002, respectively)	246,952	163,172
Subordinated unitholders (10,465,000 units outstanding at December 31, 2003 and 2002)	49,010	57,069
General Partner interest	3,975	2,329
Undistributed employee long-term incentive compensation (note 1)	738	72
Accumulated other comprehensive loss (note 1)	(5,608)	(7,375)
Net partners' capital	295,067	215,267

	2003	2002
	$ 650,203	$ 487,038

See accompanying notes to consolidated financial statements.