SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported) - March 14, 2002

PLAINS ALL AMERICAN PIPELINE, L.P.
(Name of Registrant as specified in its charter)

DELAWARE	0-9808	76-0582150
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

333 CLAY STREET, SUITE 2900
HOUSTON, TEXAS 77002
(713) 646-4100
(Address, including zip code, and telephone number, including area code, of Registrant's principal executive offices)

N/A
(Former name or former address, if changed since last report.)

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS

(c) Exhibits

23.1 Consent of PricewaterhouseCoopers LLP

99.1 Plains All American Pipeline, L.P.'s Audited 2001 Consolidated Financial Statements

SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

Date: March 14, 2002

By: Plains AAP, L.P., its general partner

By: Plains All American GP LLC, its general partner

By: /s/ Phil Kramer

Name: Phil Kramer
Title: Executive Vice President and Chief Financial Officer

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-91141, 333-54118, 333-74920) and Form S-3 (Nos. 333-59224, 333-68446) of Plains All American Pipeline, L.P. of our report dated March 6, 2002, relating to the consolidated financial statements, which appears in this Current Report on Form 8-K.

Houston, Texas
March 14, 2002

EXHIBIT 99.1

PLAINS ALL AMERICAN PIPELINE, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors of the General Partner and the Unitholders of
Plains All American Pipeline, L.P.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in partners' capital and of cash flows present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries (the "Partnership") at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting for derivatives and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2002

PAGE>

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	December 31, 2001	December 31, 2000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,511	$ 3,426
Accounts receivable and other	365,697	347,698
Inventory	188,874	46,780
Total current assets	558,082	397,904
PROPERTY AND EQUIPMENT	653,050	467,619
Less allowance for depreciation and amortization	(48,131)	(26,974)
	604,919	440,645
OTHER ASSETS		
Pipeline linefill	57,367	34,312
Other, net	40,883	12,940
	$ 1,261,251	$ 885,801
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and other current liabilities	$ 386,993	$ 328,542
Due to related party	13,685	20,951
Short-term debt and current portion of long-term debt	104,482	1,300
Total current liabilities	505,160	350,793
LONG-TERM LIABILITIES		
Bank debt	351,677	320,000
Other long-term liabilities and deferred credits	1,617	1,009
Total liabilities	858,454	671,802
COMMITMENTS AND CONTINGENCIES (Note 14)		
PARTNERS' CAPITAL		
Common unitholders (31,915,939 and 23,049,239 units outstanding at December 31, 2001 and 2000, respectively)	408,562	217,073
Class B Common unitholders (1,307,190 units outstanding at each date)	19,534	21,042
Subordinated unitholders (10,029,619 units outstanding at each date)	(38,891)	(27,316)
General partner	13,592	3,200
	402,797	213,999
	$ 1,261,251	$ 885,801

See notes to consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Year Ended December 31, 2001	2000	1999
REVENUES	$ 6,868,215	$ 6,641,187	$ 10,910,423
COST OF SALES AND OPERATIONS	6,720,970	6,506,504	10,800,109
UNAUTHORIZED TRADING LOSSES AND RELATED EXPENSES (Note 3)	-	6,963	166,440
INVENTORY VALUATION ADJUSTMENT (Note 2)	4,984	-	-
Gross Margin	142,261	127,720	(56,126)
EXPENSES			
General and administrative	46,586	40,821	23,211
Depreciation and amortization	24,307	24,523	17,344
Restructuring expense	-	-	1,410
Total expenses	70,893	65,344	41,965
OPERATING INCOME (LOSS)	71,368	62,376	(98,091)
Interest expense	(29,082)	(28,691)	(21,139)
Gain on sale of assets (Note 5)	984	48,188	16,457
Interest and other income (expense)	401	10,776	958
Income (loss) before extraordinary item and cumulative effect of accounting change	43,671	92,649	(101,815)
Extraordinary item (Note 10)	-	(15,147)	(1,545)
Cumulative effect of accounting change (Note 9)	508	-	-
NET INCOME (LOSS)	$ 44,179	$ 77,502	$ (103,360)
NET INCOME (LOSS) - LIMITED PARTNERS	$ 42,239	$ 75,754	$ (101,517)
NET INCOME (LOSS) - GENERAL PARTNER	$ 1,940	$ 1,748	$ (1,843)
BASIC AND DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT			
Income (loss) before extraordinary item and cumulative effect of accounting change	$ 1.12	$ 2.64	$ (3.16)
Extraordinary item	-	(0.44)	(0.05)
Cumulative effect of accounting change	0.01	-	-
Net income (loss)	$ 1.13	$ 2.20	$ (3.21)
WEIGHTED AVERAGE UNITS OUTSTANDING	37,528	34,386	31,633

See notes to consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 44,179	$ 77,502	$ (103,360)
Items not affecting cash flows from operating activities:			
Depreciation and amortization	24,307	24,523	17,344
(Gain) loss on sale of assets (Note 5)	(984)	(48,188)	(16,457)
Cumulative effect of accounting change	(508)	-	-
Noncash compensation expense	5,741	3,089	1,013
Allowance for doubtful accounts	3,000	5,000	-
Inventory valuation adjustment	4,984	-	-
Other non cash items	(207)	4,574	1,047
Change in assets and liabilities, net of acquisition:			
Accounts receivable and other	(18,856)	120,497	(224,181)
Inventory	(117,878)	(11,954)	34,772
Accounts payable and other current liabilities	46,671	(161,543)	164,783
Pipeline linefill	(13,736)	(16,679)	(3)
Other long-term liabilities and deferred credits	600	(8,591)	18,873
Due (to) from related party	(7,266)	(21,741)	34,924
Net cash provided by (used in) operating activities	(29,953)	(33,511)	(71,245)
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions (Note 4)	(229,162)	-	(176,918)
Additions to property and equipment	(21,069)	(12,603)	(12,801)
Disposals of property and equipment and other (Note 5)	740	223,604	3,626
Net cash provided by (used in) investing activities	(249,491)	211,001	(186,093)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of units (Note 7)	227,549	-	76,450
Costs incurred in connection with financing arrangements	(6,351)	(6,748)	(17,243)
Subordinated notes - general partner	-	(114,000)	114,000
Proceeds from long-term debt	1,837,750	1,433,750	403,721
Proceeds from short-term debt	492,005	51,300	131,119
Principal payments of long-term debt	(1,803,073)	(1,423,850)	(268,621)
Principal payments of short-term debt	(392,422)	(108,719)	(82,150)
Distributions to unitholders	(75,929)	(59,565)	(51,673)
Net cash provided by (used in) financing activities	279,529	(227,832)	305,603
Net increase (decrease) in cash and cash equivalents	85	(50,342)	48,265
Cash and cash equivalents, beginning of period	3,426	53,768	5,503
Cash and cash equivalents, end of period	$ 3,511	$ 3,426	$ 53,768

See notes to consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL
(in thousands)

	Common Units		Class B Common Units		Subordinated Units		General Partner	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Amount
Balance at December 31, 1998	20,059	$253,568	-	$ -	10,030	$ 15,995	$ 980	$ 270,543
Issuance of Class B Common Units	-	-	1,307	25,000	-	-	252	25,252
Noncash compensation expense	-	-	-	-	-	-	1,013	1,013
Issuance of units to public	2,990	50,654	-	-	-	-	544	51,198
Net loss	-	(62,598)	-	(3,218)	-	(35,701)	(1,843)	(103,360)
Distributions	-	(33,265)	-	(1,234)	-	(15,915)	(1,259)	(51,673)
Balance at December 31, 1999	23,049	208,359	1,307	20,548	10,030	(35,621)	(313)	192,973
Noncash compensation expense	-	-	-	-	-	-	3,089	3,089
Net income	-	50,780	-	2,878	-	22,096	1,748	77,502
Distributions	-	(42,066)	-	(2,384)	-	(13,791)	(1,324)	(59,565)
Balance at December 31, 2000	23,049	217,073	1,307	21,042	10,030	(27,316)	3,200	213,999
Issuance of units	8,867	222,032	-	-	-	-	5,517	227,549
Noncash compensation expense	-	-	-	-	-	-	5,741	5,741
Net income	-	29,436	-	1,476	-	11,327	1,940	44,179
Distributions	-	(51,271)	-	(2,549)	-	(19,558)	(2,551)	(75,929)
Other comprehensive income	-	(8,708)	-	(435)	-	(3,344)	(255)	(12,742)
Balance at December 31, 2001	31,916	$ 408,562	1,307	$ 19,534	10,030	$ (38,891)	$ 13,592	$ 402,797

See notes to consolidated financial statements.

Note 1 -- Organization and Basis of Presentation

Organization

We are a publicly traded Delaware limited partnership engaged in interstate and intrastate marketing, transportation and terminalling of crude oil and liquefied petroleum gas (LPG). We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly owned affiliates ("Plains Resources") as a separate, publicly traded master limited partnership.

We completed our initial public offering (IPO) in November 1998, issuing 13.1 million common units at $20.00 per unit and received net proceeds of $244.7 million. Concurrently with the offering, Plains Resources sold certain assets to us and contributed other assets in exchange for cash, common and subordinated units, an aggregate 2% general partner interest, the right to receive incentive distributions as defined in the partnership agreement and the assumption of related indebtedness. Immediately after our initial public offering, Plains Resources owned 100% of our general partner interest and an overall effective ownership in the Partnership of 57% (including the 2% general partner interest and common and subordinated units owned by it).

In May 2001, senior management of our general partner and a group of financial investors entered into a transaction with Plains Resources to acquire control of the general partner interest and a majority of the outstanding subordinated units. The transaction closed in June 2001, and for purposes of this report is referred to as the "General Partner Transition." As a result of this transaction, Plains Resources' ownership in the general partner was reduced from 100% to 44%. Additionally, as a result of this transaction and various equity offerings conducted since the IPO, Plains Resources' overall effective ownership has been reduced to approximately 29%.

The general partner interest is now held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Our operations and activities are managed by, and our officers and personnel are employed by, Plains All American GP LLC. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. We use the phrase "former general partner" to refer to the subsidiary of Plains Resources that formerly held the general partner interest.

We conduct our operations through our wholly owned operating limited partnerships Plains Marketing, L.P., All American Pipeline, L.P., and Plains Marketing Canada, L.P. Our operations are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta, Saskatchewan and Manitoba.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2001 and 2000, and the results of our operations, cash flows and changes in partners' capital for the years ended December 31, 2001, 2000 and 1999. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior period amounts to conform with the current period presentation.

Note 2 -- Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include (1) estimated useful lives of assets, which impacts depreciation and amortization, (2) allowance for doubtful accounts receivable, (3) accruals related to revenues and expenses and (4) liability and contingency accruals. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Gathering and marketing revenues are accrued at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Terminalling and storage revenues are recognized at the time service is performed. Revenues for the transportation of crude oil are recognized either at the point of delivery or at the point of receipt pursuant to regulated and non-regulated tariffs.

Cost of Sales and Operations

Cost of sales and operations consists of the cost of crude oil, transportation and storage fees, field and pipeline operating expenses and letter of credit expenses. Field and pipeline operating expenses consist primarily of fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance, utilities, insurance and property taxes.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided in the form of standby letters of credit.

We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. At December 31, 2001, approximately 93% of accounts receivable were less than 60 days past scheduled invoice date. At December 31, 2001, our allowance for doubtful accounts receivable totaled $3.0 million for receivables included in current assets and $5.0 million for receivables classified as long-term, representing 11% and 33%, respectively, of all balances greater than 60 days past scheduled invoice date. There was no allowance for doubtful accounts at December 31, 1999. We consider these reserves adequate. Amounts due from affiliated entities at December 31, 2001, totaled less than $0.6 million and represented amounts due under current contracts in the ordinary course of business or billings for reimbursing expenses that were collected subsequent to year end. None of the accounts receivables are related to any equity investments in the Partnership.

Inventory

Inventory consists of liquefied petroleum gas and crude oil in pipelines, storage tanks and rail cars which is valued at the lower of cost or market, with cost determined using an average cost method. In the fourth quarter of 2001, the Partnership recorded a $5.0 million noncash writedown of operating crude oil inventory to reflect prices at December 31, 2001. During 2001, the price of crude oil traded on the NYMEX averaged $25.98 per barrel. At December 31, 2001, the NYMEX crude oil price was approximately 24% lower, or $19.84 per barrel.

Property and Equipment and Pipeline Linefill

Property and equipment is stated at cost and consists of (in thousands):

	December 31, 2001	December 31, 2000
Crude oil pipelines	$ 470,671	$ 359,826
Crude oil pipeline facilities	87,446	39,358
Crude oil storage and terminal facilities	62,974	45,989
Trucking equipment, injection stations and other	25,599	19,435
Office property and equipment	6,360	3,011
	653,050	467,619
Less accumulated depreciation and amortization	(48,131)	(26,974)
	$ 604,919	$ 440,645

Depreciation is computed using the straight-line method over estimated useful lives as follows:

- crude oil pipelines - 30 years;
- crude oil pipeline facilities - 30 years;
- crude oil storage and terminal facilities - 30 to 40 years;
- trucking equipment, injection stations and other - 5 to 15 years; and
- office property and equipment - 5 years

Acquisitions and improvements are capitalized; maintenance and repairs are expensed as incurred.

Pipeline linefill is recorded at cost and consists of liquefied petroleum gas and crude oil linefill used to pack a pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location as well as minimum crude oil necessary to operate our storage and terminalling facilities. At December 31, 2001, we had approximately 2.6 million barrels of crude oil and 6.4 million gallons of liquefied petroleum gas used to maintain our minimum operating linefill requirements. Proceeds from the sale and repurchase of pipeline linefill are reflected as cash flows from operating activities in the accompanying consolidated statements of cash flows.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value. Fair value is generally determined from estimated discounted future net cash flows.

Other Assets

Other assets consist of the following (in thousands):

	December 31, 2001	December 31, 2000
Debt issue costs	$ 17,293	$ 8,918
Long term receivable, net	10,000	5,000
Goodwill	9,419	601
Intangible assets (contracts)	980	-
Other	7,649	169
	45,341	14,688
Less accumulated amortization	(4,458)	(1,748)
	$ 40,883	$ 12,940

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Goodwill is recorded as the amount of the purchase price in excess of the fair value of certain assets purchased. In accordance with Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets", which we will adopt in its entirety January 1, 2002, we will test goodwill and other intangible assets periodically to determine whether an impairment has occurred. An impairment occurs when the carrying amount of an asset exceeds the fair value of the recognized goodwill or intangible asset. If impairment occurs, the loss is recorded in the period.

Income and Other Taxes

No provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax bases cannot be readily determined. Accordingly, we do not believe that in our circumstances, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital-based tax at federal and provincial levels. For 2001, the income tax was not material and the capital-based tax was approximately $0.4 million (U.S.). In addition, interest payments made by Plains Marketing Canada, L.P. on its intercompany loan from Plains Marketing, L.P. are subject to a 10% Canadian withholding tax, which for 2001 totaled $0.3 million and is recorded in other expense.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes and to file state income tax returns and to pay taxes in various states.

Hedging

We utilize various derivative instruments, for purposes other than trading, to hedge our exposure to price fluctuations on crude oil and liquefied petroleum gas in storage and expected purchases, sales and transportation of those commodities. The derivative instruments consist primarily of futures and option contracts traded on the New York Mercantile Exchange and over-the-counter transactions including crude oil swap contracts entered into with financial institutions. We also utilize interest rate and foreign exchange swaps and collars to manage the interest rate exposure on our long-term debt and foreign exchange exposure arising from our Canadian operations.

Beginning January 1, 2001, we record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities". Generally for our domestic U.S. operations, these derivative instruments qualify for hedge accounting as they reduce the price risk of the underlying hedged item and are designated as a hedge at inception. These derivative hedges result in financial impacts that are inversely correlated to those of the items being hedged. This correlation, generally in excess of 80% (a measure of hedge effectiveness), is measured both at the inception of the hedge and on an ongoing basis. To qualify for hedge accounting treatment, companies must formally document, designate and assess the effectiveness of these transactions. If the necessary correlation ceases to exist or if physical delivery of the hedged item becomes improbable, we would discontinue hedge accounting and apply mark to market accounting. Gains and losses on the termination of hedging instruments are deferred and recognized in income as the impact of the hedged item is recorded.

SFAS 133 requires that changes in derivative contracts' fair value be recognized currently in earnings unless specific hedge accounting criteria are met. We have some derivative contracts, primarily related to our LPG activities, that do not receive hedge treatment, as the correlation is not consistently at the necessary level between prices for those markets or commodities and the hedging instrument. As a result, gains and losses on those derivative contracts impact earnings directly. The intent of entering into these transactions, however, is to mitigate price exposure arising from those operations.

Aside from the exceptions noted above, unrealized changes in the market value of crude oil or LPG hedge contracts are not generally recognized in our consolidated statement of operations until the underlying hedged transaction occurs. The financial impacts of these hedge contracts are included in our consolidated statements of operations as a component of revenues. Such financial impacts are offset by gains or losses realized in the physical market. Cash flows from these hedging activities are included in operating activities in the accompanying consolidated statements of cash flows. Net deferred gains and losses on futures contracts (including closed futures contracts) entered into to hedge anticipated crude oil and LPG purchases and sales, are included in current assets or current liabilities in the accompanying consolidated balance sheets. Deferred gains or losses from inventory hedges are included as part of the inventory costs and recognized when the related inventory is sold.

Amounts paid or received from interest rate swaps and collars are charged or credited to interest expense and matched with the cash flows and interest expense of the debt being hedged, resulting in an adjustment to the effective interest rate.

Net Income Per Unit

Basic and diluted net income (loss) per unit is determined by dividing net income (loss) after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding common units and subordinated units. Partnership income (loss) is first allocated according to percentage ownership in the Partnership and then reallocated between the limited partners and general partner based on the amount of incentive distributions. Basic and diluted net income (loss) per unit for 2001, 2000 and 1999 is as follows (in thousands, except per unit data):

	Year Ended December 31, 2001	2000	1999
Net income (loss)	$ 44,179	$ 77,502	$ (103,360)
Less:			
General partner incentive distributions	(1,056)	(198)	(224)
General partner 2% ownership	(884)	(1,550)	2,067
Net income (loss) attributable to limited partners	$ 42,239	$ 75,754	$ (101,517)
Weighted average units outstanding	37,528	34,386	31,633
Basic and diluted net income (loss) per limited partner unit	$ 1.13	$ 2.20	$ (3.21)

Foreign Currency Translation

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U. S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues and expenses are translated using the average exchange rate during the reporting period.

Recent Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 141 "Business Combinations" and SFAS 142 "Goodwill and Other Intangible Assets". SFAS 141 requires all business combinations initiated after June 30, 2001 (see Note 4), to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, this Standard also establishes specific criteria for the recognition of intangible assets separately from goodwill. We have adopted SFAS 142 effective January 1, 2002. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to forty years. In conjunction with the adoption of SFAS 142, amortization on the unamortized portion of the goodwill arising from previous acquisitions will cease in 2002. The adoption of SFAS 142 will not have a material effect on either our financial position, results of operations, or cash flows.

In June 2001, the FASB also issued SFAS 143, "Asset Retirement Obligations". SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. We will adopt the statement effective January 1, 2003, as required. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. At this time, we cannot reasonably estimate the effect of the adoption of this statement on either our financial position, results of operations, or cash flows.

In August 2001, the FASB approved SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets". SFAS 144 establishes a single accounting model for long-lived assets to be disposed of by sale and provides additional implementation guidance for assets to be held and used and assets to be disposed of other than by sale. Upon adoption of this Statement effective January 1, 2002, there was no effect on either our financial position, results of operations or cash flows.

In June 1998, the FASB issued SFAS 133, which was subsequently amended (i) in June 1999 by SFAS 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133", which deferred the effective date of SFAS 133 to fiscal years beginning after June 15, 2000; and (ii) in June 2000 by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedge Activities," which amended certain provisions, inclusive of the definition of the normal purchase and sale exclusion. We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion.

SFAS 133 requires that all derivative instruments be recorded on the balance sheet as either assets or liabilities measured at their fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if so, the type of hedge transaction. For fair value hedge transactions in which we are hedging changes in the fair value of an asset, liability, or firm commitment, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the fair value of the hedged item. For cash flow hedge transactions, in which we are hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income, a component of partners' capital. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are affected by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in earnings in the current period. Hedge effectiveness is measured at least quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time.

We adopted SFAS 133, as amended, effective January 1, 2001. Our implementation procedures identified all instruments in place at the adoption date that are subject to the requirements of SFAS 133. Upon adoption, we recorded a cumulative effect charge of $8.3 million in accumulated other comprehensive income to recognize at fair value all derivative instruments that are designated as cash flow hedging instruments and a cumulative effect gain of $0.5 million to earnings. Correspondingly, an asset of $2.8 million and a liability of $10.6 million were established. Hedge losses/gains included in accumulated other comprehensive income are transferred to earnings as the forecasted transactions actually occur. Implementation issues continue to be addressed by the FASB and any change to existing guidance might impact our implementation. Adoption of this standard will most likely increase volatility in earnings and partners' capital through comprehensive income.

Note 3 -- Unauthorized Trading Losses

In November 1999, we discovered that a former employee had engaged in unauthorized trading activity, resulting in losses of approximately $162.0 million ($174.0 million, including estimated associated costs and legal expenses). A full investigation into the unauthorized trading activities by outside legal counsel and independent accountants and consultants determined that the vast majority of the losses occurred from March through November 1999. Approximately $7.1 million of the unauthorized trading losses was recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $7.0 million charge for litigation related to the unauthorized trading losses (see Note 14).

Note 4 -- Acquisitions

Wapella Pipeline System

In December 2001, we acquired the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs. The system is located in southeastern Saskatchewan and southwestern Manitoba. In 2001, the Wapella Pipeline System delivered approximately 11,000 barrels per day of crude oil to the Enbridge Pipeline at Cromer, Manitoba. The acquisition also includes approximately 21,500 barrels of crude oil storage capacity located along the system as well as a truck terminal. Initial financing for the acquisition was provided through borrowings under our bank credit facility.

The Wapella acquisition has been accounted for using the purchase method of accounting and the purchase price was allocated in accordance with SFAS 141 (see Note 2). The purchase price allocation is as follows (in thousands):

Crude oil pipeline, gathering and terminal assets	$ 10,251
Other property and equipment	1,720
Total	$ 11,971

CANPET Energy Group Inc.

In July 2001, we acquired the assets of CANPET Energy Group Inc. ("CANPET"), a Calgary-based Canadian crude oil and liquefied petroleum gas marketing company, for approximately $42.0 million plus excess inventory at the closing date of approximately $25.0 million. Approximately $24.0 million of the purchase price plus $25.0 million for the additional inventory was paid in cash at closing, and the remainder, which is subject to certain performance standards, will be paid in common units in April 2004, if such standards are met. At the time of the acquisition, CANPET's activities consisted of gathering approximately 75,000 barrels per day of crude oil and marketing an average of approximately 26,000 barrels per day of natural gas liquids or LPG's. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and working capital of approximately $8.6 million. Initial financing for the acquisition was provided through borrowings under our bank credit facility.

The CANPET acquisition has been accounted for using the purchase method of accounting and the purchase price was allocated in accordance with SFAS 141 (see Note 2). The purchase price allocation is as follows (in thousands):

Inventory	$ 29,708
Goodwill	8,818
Intangible assets (contracts)	980
Other assets, including debt issue costs	1,661
Pipeline linefill	4,332
Crude oil gathering and terminal assets	4,243
Other property and equipment	502
Total	$ 50,244

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we closed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $161.0 million in cash ("the Murphy Acquisition"), including financing and transaction costs. Initial financing for the acquisition was provided through borrowings under our bank credit facilities. The purchase included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 450 miles of crude oil and condensate transmission mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, an inactive 108-mile mainline system and 121 trailers used primarily for crude oil transportation. We have reactivated the 108-mile mainline system and began shipping volumes in May of 2001.

Murphy agreed to continue to transport production from fields previously delivering crude oil to these pipeline systems, under a long-term contract. At the time of the acquisition, the volume under the contract was approximately 11,000 barrels per day. Total volumes transported on the pipeline system in 2001 were approximately 223,000 barrels per day of light, medium and heavy crudes, as well as condensate.

The Murphy Acquisition has been accounted for using the purchase method of accounting and the purchase price was allocated in accordance with Accounting Principles Board Opinion No. 16, Business Combinations ("APB 16"). The purchase price allocation, as adjusted pursuant to the provisions of the purchase and sale agreement upon resolution of an outstanding pipeline tariff dispute, is as follows (in thousands):

Crude oil pipeline, gathering and terminal assets	$145,106
Pipeline linefill	7,602
Net working capital items	1,953
Other property and equipment	487
Other assets, including debt issue costs	360
Total	$155,508

Pro Forma Results for the Murphy and CANPET Acquisitions

The following unaudited pro forma data is presented to show pro forma revenues, net income and basic and diluted net income per limited partner unit for the Partnership as if the Murphy and CANPET acquisitions had occurred on January 1, 2000 (in thousands):

	Year Ended December 31, 2001 (1)	Year Ended December 31, 2000 (1)
Revenues	$ 7,043,143	$ 7,330,621
Income before extraordinary item and cumulative effective of accounting change	$ 51,905	$ 98,821
Net income	$ 52,413	$ 83,674
Basic and diluted income before extraordinary item and cumulative effect of accounting change per limited partner unit	$ 1.32	$ 2.81
Basic and diluted net income per limited partner unit	$ 1.33	$ 2.38

(1) The pro forma information does not include the results of the Wapella acquisition as it would not differ materially from the reported results.

Scurlock Acquisition

On May 12, 1999, we completed the acquisition of Scurlock Permian LLC and certain other pipeline assets from Marathon Ashland Petroleum LLC. Including working capital adjustments and closing and financing costs, the cash purchase price was approximately $141.7 million.

Financing for the Scurlock acquisition was provided through:

- borrowings of approximately $92.0 million under a previous bank facility;
- the sale to our former general partner of 1.3 million of our Class B common units for a total cash consideration of $25.0 million, or $19.125 per unit, the price equal to the market value of our common units on May 12, 1999; and
- a $25.0 million draw under our revolving credit agreement.

The assets, liabilities and results of operations of Scurlock are included in our consolidated financial statements effective May 1, 1999. The Scurlock acquisition has been accounted for using the purchase method of accounting and the purchase price was allocated in accordance with APB 16 as follows (in thousands):

Crude oil pipeline, gathering and terminal assets	$ 125,120
Other property and equipment	1,546
Pipeline linefill	16,057
Other assets (debt issue costs)	3,100
Other long-term liabilities (environmental accrual)	(1,000)
Net working capital items	(3,090)
Cash paid	$ 141,733

The purchase accounting entries include a $1.0 million accrual for estimated environmental remediation costs. Under the agreement for the sale of Scurlock by Marathon Ashland Petroleum, Marathon Ashland Petroleum has agreed to indemnify us and hold us harmless for claims, liabilities and losses resulting from any act or omission attributable to Scurlock's business or properties occurring prior to the date of the closing of such sale to the extent the aggregate amount of such losses exceed $1.0 million; provided, however, that claims for such losses must individually exceed $25,000 and must be asserted by us against Marathon Ashland Petroleum on or before May 15, 2003.

West Texas Gathering System Acquisition

On July 15, 1999, we completed the acquisition of a West Texas crude oil pipeline and gathering system from Chevron Pipe Line Company for approximately $36.0 million, including transaction costs. Our total acquisition cost was approximately $38.9 million including costs to address certain issues identified in the due diligence process. The principal assets acquired include approximately 450 miles of crude oil transmission mainlines, approximately 400 miles of associated gathering and lateral lines and approximately 2.9 million barrels of crude oil storage and terminalling capacity in Crane,

Ector, Midland, Upton, Ward and Winkler Counties, Texas. Financing for the amounts paid at closing was provided by a draw under a previous credit facility.

Note 5 -- Asset Disposition

In December 2001, we sold excess communications equipment remaining from the sale of the All American Pipeline discussed below and recognized a gain of $1.0 million.

In March 2000, we sold to a unit of El Paso Corporation for $129.0 million the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas. Except for minor third-party volumes, one of our subsidiaries, Plains Marketing, L.P., was the sole shipper on this segment of the pipeline since the acquisition of the line from Goodyear in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We had suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized gains of approximately $28.1 million and $16.5 million in 2000 and 1999, respectively, in connection with the sale of the linefill.

Note 6 -- Debt

Short-term debt and current maturities of long-term debt consist of the following (in thousands):

	December 31, 2001	December 31, 2000
$200.0 million senior secured letter of credit and borrowing facility bearing interest at a weighted average interest rate of 3.8% at December 31, 2001, and 8.4% at December 31, 2000	$ 100,000	$ 1,300
Other	1,482	-
	101,482	1,300
Current portion of long-term debt	3,000	-
Total short-term debt and current maturities of long-term debt	$ 104,482	$ 1,300

Long-term debt consists of the following (in thousands):

	December 31, 2001	December 31, 2000
$450.0 million senior secured domestic revolving credit facility, bearing interest at a weighted average interest rate of 4.5% at December 31, 2001, and 9.2% at December 31, 2000	$ 27,450	$ 320,000
$200.0 million senior secured term B loan, bearing interest at a weighted average interest rate of 4.5% at December 31, 2001	200,000	-
$100.0 million senior secured term loan, bearing interest at a weighted average interest rate of 4.4% at December 31, 2001	100,000	-
$30.0 million Canadian senior secured revolving credit facility, bearing interest at a weighted average interest rate of 4.4% at December 31, 2001	27,227	-
	354,677	320,000
Less current maturities	(3,000)	-
Total long-term debt	$ 351,677	$ 320,000

In September 2001, we amended and expanded our credit facilities to include a six-year, $200.0 million term B loan. In connection with this amendment, we reduced the revolving portion of the facilities by $50.0 million. Our credit facilities currently consist of:

- a $780.0 million senior secured revolving credit and term loan facility, which is secured by substantially all of our assets. The facility consists of (i) a $450.0 million domestic revolving facility (reflecting the $50 million reduction in such facility in connection with the September amendment), with a $10.0 million letter of credit sublimit, (ii) a $30.0 million Canadian revolving facility (with a $5.0 million letter of credit sublimit), (iii) a $100.0 million term loan and (iv) a $200.0 million term B loan. The facility matures, (i) as to the aggregate $480.0 million domestic and Canadian revolver portions, in April 2005, (ii) as to the $100.0 million term portion, in May 2006, and, (iii) as to the $200.0 million term B loan portion, September 2007. On the revolver portions, no principal is scheduled for payment prior to maturity. The $100.0 million term loan portion of this facility has four scheduled annual payments of principal, commencing May 4, 2002, in the respective amounts of 1%, 7%, 8% and 8% of the original term principal amount, with the remaining principal balance scheduled for payment on the stated maturity date of May 5, 2006. If any part of the term portion is prepaid prior to its first anniversary, a 1% premium will be due on that portion. The $200.0 million term B loan has 1% payable yearly commencing on September 21, 2002, with the remaining principal balance scheduled for payment on the stated maturity date of September 26, 2007. The term B loan may be prepaid without penalty. The revolving credit and term loan facility bears interest at our option at either the base rate, as defined, plus an applicable margin, or LIBOR plus an applicable margin, and further, the Canadian revolver may effectively bear interest based upon bankers' acceptance rates. We incur a commitment fee on the unused portion of the revolver portion of this credit facility.

- a $200.0 million senior secured letter of credit and borrowing facility, the purpose of which is to provide standby letters of credit to support the purchase and exchange of crude oil and other specified petroleum products for resale and borrowings to finance crude oil inventory and other specified petroleum products that have been hedged against future price risk. The letter of credit facility is secured by substantially all of our assets and has a sublimit for cash borrowings of $100.0 million to purchase crude oil and other petroleum products that have been hedged against future price risk and to fund margin requirements under NYMEX contracts used to facilitate our hedging activities. The letter of credit facility expires in April 2004. Aggregate availability under the letter of credit facility for direct borrowings and letters of credit is limited to a borrowing base that is determined monthly based on certain of our current assets and current liabilities, primarily inventory and accounts receivable and accounts payable related to the purchase and sale of crude oil and other specified petroleum products. We incur a commitment fee on the unused portion of this facility.

Our credit facilities prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness;
- grant liens;
- sell assets;
- make investments;
- engage in transactions with affiliates;
- enter into certain contracts; and
- enter into a merger or consolidation.

Our credit facilities treat a change of control as an event of default and also require us to maintain:

- a current ratio (as defined) of 1.0 to 1.0;
- a debt coverage ratio which is not greater than 4.00 to 1;
- an interest coverage ratio which is not less than 2.75 to 1.0; and
- a debt to capital ratio of not greater than 0.70 to 1.0 prior to December 31, 2002, and 0.65 to 1.0 thereafter.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt and to foreclose on the assets securing the credit facilities. As long as we are in compliance with our commercial credit agreements, they do not restrict our ability to make distributions of "available cash" as defined in our partnership agreement. We are currently in compliance with the covenants contained in our credit agreements.

The credit facilities provide that the Partnership may issue up to $400.0 million of senior unsecured debt that has a maturity date extending beyond the maturity date of the credit facilities. If senior unsecured debt is issued, the aggregate amount available under the $450.0 million U.S. revolving credit facility will be reduced by an amount equal to (a) 40% of the face amount of the senior unsecured debt if the aggregate amount of new debt issued is less than $350.0 million, or (b) 50% of the face amount of the senior unsecured debt if the aggregate amount of new debt issued is equal to or greater than $350.0 million; provided, however, in both cases, the amount of the revolver reduction is decreased by $50.0 million.

In January 2002, we amended our credit facility to remove a condition requiring us to obtain lender approval before making any acquisition greater than $50.0 million to provide the Partnership with greater structuring flexibility to finance larger acquisitions.

Maturities

The aggregate amount of maturities of all long-term indebtedness at December 31, 2001, for the next five years is: 2002 - $3.0 million, 2003 - $9.0 million, 2004 - $10.0 million, 2005 - $64.7 million, 2006 and thereafter -$268.0 million.

Note 7 - Partners' Capital and Distributions

Partners' capital consists of (1) 33,223,129 common units, including 1,307,190 Class B common units, representing a 75.3% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), (2) 10,029,619 Subordinated units representing a 22.7% effective aggregate ownership interest in the Partnership and its subsidiaries limited partner interest (after giving affect to the general partner interest) and (3) a 2% general partner interest.

In May 2001, we completed a public offering of 3,966,700 common units. Total net cash proceeds from the offering, including our former general partner's proportionate contribution, were approximately $100.7 million. In addition, in October 2001, we completed a public offering of 4,900,000 common units. Net cash proceeds from the offering, including our general partner's proportionate contribution, were approximately $126.0 million. The net proceeds were used to repay borrowings under our revolving credit facility, a portion of which was used to finance our Canadian acquisitions.

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Distributions of available cash to holders of subordinated units are subject to the prior rights of holders of common units to receive the minimum quarterly distribution ("MQD") for each quarter during the subordination period and to receive any arrearages in the distribution of the MQD on the common units for the prior quarters during the subordination period. There were no arrearages on common units at December 31, 2001. The MQD is $0.45 per unit ($1.80 per unit on an annual basis). Common units will not accrue arrearages with respect to distributions for any quarter after the subordination period and subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The subordination period (as defined in the partnership agreement) will end if certain financial tests are met for three consecutive four-quarter periods (the "testing period"), but not sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units, and will participate pro rata with all other common units in future distributions. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003. We have determined that the first four-quarter period of the testing period was satisfied as of September 30, 2001. Although we cannot give assurance in that regard, if we continue to meet the requirements, 25% of the subordinated units will convert in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004.

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled to 15% of amounts we distribute in excess of $0.450 per unit, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit. Cash distributions for the first, second, third and fourth quarters of 2001 were $0.4750, $0.5000, $0.5125 and $0.5125, respectively, per unit on our outstanding common units, Class B units and subordinated units, representing an excess of $0.025, $0.050, $0.0625 and $0.0625 per unit, respectively, over the MQD. Cash distributions for the second, third and fourth quarters of 2000 were $0.4625 per unit on our outstanding common units, Class B units and subordinated units, representing an excess of $0.0125 per unit over the MQD. Cash distributions for the second and third quarters of 1999 were $0.4625 and $0.4812 per unit, respectively, on our outstanding common units, Class B units and subordinated units, representing an excess of $0.0125 per unit and $0.0312 per unit, respectively, over the MQD. Distributions were not paid on the subordinated units for the fourth quarter of 1999.

The Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. The Class B unitholders may request that we call a meeting of common unitholders to consider approval of the conversion of Class B units into common units. If the approval of a conversion by the common unitholders is not obtained within 120 days of a request, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

Note 8 -- Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to Partners' Capital and classified as Other Comprehensive Income (OCI). Such amounts are allocated in proportion to the limited partners and general partners interest. Following the adoption of SFAS 133, we recorded a charge to OCI of $8.3 million related to the change in fair value of certain derivative financial instruments that qualified for cash flow hedge accounting. The following table reflects comprehensive income for the year ended December 31, 2001 (in thousands):

Total comprehensive income at January 1, 2001	$ -
Cumulative effect of change in accounting principle	(8,337)
Reclassification adjustment for settled contracts	(2,526)
Changes in fair value of outstanding hedging positions	6,123
Currency translation adjustment	(8,002)
Other comprehensive income (loss)	(12,742)
Net income	44,179
Total comprehensive income at December 31, 2001	$ 31,437

Note 9 -- Financial Instruments

Derivatives

On January 1, 2001, we adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138. In accordance with the transition provisions of SFAS 133, we recorded a loss of $8.3 million in OCI, representing the cumulative effect of an accounting change to recognize, at fair value, all cash flow derivatives. We also recorded a noncash gain of $0.5 million in earnings as a cumulative effect adjustment.

At December 31, 2001, a $4.7 million unrealized loss was recorded to OCI together with related assets and liabilities of $4.2 million and $8.2 million, respectively. Earnings included a noncash gain of $0.2 million (excluding the $0.5 million gain related to the cumulative effect of accounting change upon adoption of SFAS 133) related to the ineffective portion of our cash flow hedges, as well as certain derivative contracts that did not qualify as hedges primarily relating to our LPG activities due to a low correlation between the futures contract and hedged item. Our hedge-related assets and liabilities are included in other current assets and other current liabilities in the consolidated balance sheet.

As of December 31, 2001, the total amount of deferred net losses on derivative instruments recorded in OCI are expected to be reclassified to earnings during 2002 and 2003. The following table sets forth our open crude oil hedge positions at December 31, 2001. These are futures hedges and have offsetting physical exposures to the extent they are effective.

	2002				2003			
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Volume (bbls)								
Short positions	1,228,000	-	200,000	-	-	200,000	-	1,800,000
Long positions	-	1,053,000	-	-	-	-	-	-
Average price ($/bbl)	$ 20.64	$ 22.73	$ 19.53	$ -	$ -	$ 21.26	$ -	$ 21.23

Interest rate swaps and collars are used to hedge underlying interest obligations. These instruments hedge interest rates on specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments. At December 31, 2001, we had interest rate swap and collar arrangements for an aggregate notional principal amount of $275.0 million for which we would pay approximately $5.3 million if such arrangements were terminated as of such date.

The table shown below summarizes the fair value of our interest rate swaps and collars by year of maturity (in thousands):

	Year of Maturity			
	2002	2003	2004	Total
Interest rate swaps	$ --	$ (810)	$ (689)	$ (1,499)
Interest rate collars	(3,777)	--	--	(3,777)
Total	$ (3,777)	$ (810)	$ (689)	$ (5,276)

The adjustment to interest expense resulting from interest rate swaps for the years ended December 31, 2001, 2000 and 1999 was a $2.4 million loss, a $0.1 million gain and a $0.1 million loss, respectively. These instruments are based on LIBOR rates. The collar provides for a floor of 6.1% and a ceiling of 8.0% with an expiration date of August 2002 for $125.0 million notional principal amount. The fixed rate interest rate swaps provide for a rate of 4.3% for $50.0 million notional principal amount expiring March 2004, and a rate of 3.6% for $100.0 million notional principal amount expiring September 2003.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. Hedge effectiveness is measured on a quarterly basis. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. No amounts were excluded from the computation of hedge effectiveness.

Since substantially all of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at December 31, 2001, $25.4 million ($40.5 million CAD) of our long-term debt was denominated in Canadian dollars. All of the financial instruments utilized are placed with large creditworthy financial institutions and meet the criteria under SFAS 133 for hedge accounting treatment.

At December 31, 2001, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U. S. (based on a Canadian-U.S. dollar exchange rate of 1.55) quarterly during 2002 and 2003. If these contracts were terminated on December 31, 2001, we would receive $0.5 million U.S. At December 31, 2001, we also had a cross currency swap contract for an aggregate notional principal amount of $25.0 million, effectively converting this amount of our $100.0 million senior secured term loan (25% of the total) from U.S. dollars to $38.7 million of Canadian dollar debt (based on a Canadian-U.S. dollar exchange rate of 1.55). The terms of this contract mirror the term loan, matching the amortization schedule and final maturity in May 2006. If this swap contract was terminated on December 31, 2001, we would receive $0.5 million U.S.

The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in thousands):

	Year of Maturity			
	2002	2003	2006(1)	Total
Forward exchange contracts	$ 123	$ 100	$ --	$ 223
Forward extra options	145	146	--	291
Cross currency swaps	--	--	497	497
Total	$ 268	$ 246	$ 497	$ 1,011

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(1) At December 31, 2001, we did not have foreign currency hedges expiring in 2004 or 2005.

Fair Value of Financial Instruments

The carrying values of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying value of bank debt approximates fair value as interest rates are variable, based on prevailing market rates. Crude oil futures contracts permit settlement by delivery of the crude oil and, therefore, are not

financial instruments, as defined. The fair value of crude oil swap and option contracts and interest rate swap and collar agreements are based on current termination values or quoted market prices of comparable contracts.

The carrying amounts and fair values of our financial instruments are as follows (in thousands):

	December 31,			
	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Unrealized gain (loss) on interest rate swaps and collars	$ (5,276)	$ (5,276)	$ -	$ (561)

Note 10 -- Early Extinguishment of Debt

During 2000, we recognized extraordinary losses, consisting primarily of unamortized debt issue costs, totaling $15.1 million related to the permanent reduction of the All American Pipeline, L.P. term loan facility and the refinancing of our credit facilities. In addition, interest and other income for the year ended December 31, 2000, included $9.7 million of previously deferred gains from terminated interest rate swaps as a result of debt extinguishments (see Note 3). The extraordinary loss of $1.5 million in 1999 relates to the write-off of certain debt issue costs and penalties associated with the prepayment of debt.

Note 11 -- Major Customers and Concentration of Credit Risk

Customers accounting for 10% or more of revenues were as follows for the periods indicated:

	Percentage Year Ended December 31,		
	2001	2000	1999
Marathon Ashland Petroleum	11%	12%	-
Sempra Energy Trading Corporation	-	-	22%
Koch Oil Company	-	-	19%

All of the customers above pertain to our marketing, gathering, terminalling and storage segment. We believe that the loss of the customer included above for 2001 would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced.

Note 12 -- Related Party Transactions

Reimbursement of Expense of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner. Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner in 2001 were approximately $31.3 million. Total costs reimbursed by us to our former general partner and Plains Resources were approximately $31.2 million, $63.8 million and $44.7 million for the years ended December 31, 2001, 2000 and 1999, respectively. Such costs include, (1) allocated personnel costs (such as salaries and employee benefits) of the personnel providing such services, (2) rent on office space allocated to our general partner in Plains Resources' offices in Houston, Texas, (3) property and casualty insurance premiums and (4) out-of-pocket expenses related to the provision of such services.

Crude Oil Marketing Agreement

We are the exclusive marketer/purchaser for all of Plains Resources' equity crude oil production. The marketing agreement with Plains Resources provides that we will purchase for resale at market prices all of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2001, 2000 and 1999, we paid Plains Resources approximately $223.2 million, $244.9 million and $131.5 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $1.8 million, $1.7 million and $1.5 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In November 2001, the marketing agreement automatically extended for an additional three-year period.

Separation Agreement

A separation agreement was entered into in connection with the General Partner Transition pursuant to which (i) Plains Resources has indemnified us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001 or (b) claims related to the upstream business, whenever arising, and (ii) we have indemnified Plains Resources for claims related to the midstream business, whenever arising. Plains Resources also has agreed to indemnify and maintain liability insurance for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.

Financing

In May 2000, we repaid to our former general partner $114.0 million of subordinated debt. Interest expense related to the notes was $3.3 million and $0.6 million for the years ended December 31, 2000 and 1999, respectively.

To finance a portion of the purchase price of the Scurlock acquisition, we sold to our former general partner 1.3 million Class B common units at $19.125 per unit, the market value of our common units on May 12, 1999 (see Note 4).

The balance of amounts due to related parties at December 31, 2001 and 2000 was $13.7 million and $21.0 million, respectively, and was related to crude oil purchased by us but not yet paid as of December 31 of each year.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates. Under these grants, the common units vested based on attaining a targeted operating surplus for a given year. Of the 400,000 units subject to the transaction grant agreements, 69,444 units vested in 2000 for 1999's operating results and 133,336 units vested in 2001 for 2000's operating results. The remainder (197,220 units) vested in connection with the consummation of the General Partner Transition. Distribution equivalent rights were paid in cash at the time of the vesting of the associated common units. The values of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001, 2000 and 1999 were $5.7 million, $3.1 million and $1.0 million, respectively. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Performance Option Plan

In connection with the General Partner Transition, all except one of the owners of the general partner contributed an aggregate of 450,000 subordinated units to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 332,500 units have been granted to officers and key employees of our general partner. Such options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The options will vest immediately upon a change in control (as defined in the grant agreements). The purchase price under the options is $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. The terms of future grants may differ from the existing grants. Because the subordinated units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options, but will have a noncash compensation charge offset by a deemed capital contribution.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units with a value equal to the discounted present value of the spread on the unvested options, with distribution equivalent rights from the date of grant. The subordinated units vest on the same schedule as the stock options would have vested. The general partner will administer the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants will be provided by Plains Resources, we will have no obligation to reimburse the general partner for the cost of such units.

Benefit Plan

A subsidiary of Plains Resources was, until June 8, 2001, our general partner. On that date, such entity transferred the general partner interest to Plains AAP, L.P. Effective July 1, 2001, Plains All American GP LLC (Plains AAP, L.P.'s general partner), now maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the period July 1 through December 31, 2001, defined contribution plan expense was approximately $1.1 million.

Prior to July 1, 2001, Plains Resources maintained a 401(k) defined contribution plan whereby it matched 100% of an employee's contribution (subject to certain limitations in the plan), with matching contributions being made 50% in cash and 50% in common stock (the number of shares for the stock match being based on the market value of the common stock at the time the shares were granted). For the period January 1 through June 30, 2001, defined contribution plan expense was $1.0 million. For the years ended December 31, 2000 and 1999, defined contribution plan expense was approximately $1.0 million and $0.7 million, respectively.

Note 13 -- Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan for employees and directors of our general partner and its affiliates who perform services for us. The Long-Term Incentive Plan consists of two components, a restricted unit plan and a unit option plan. The Long-Term Incentive Plan currently permits the grant of restricted units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the Long-Term Incentive Plan at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the Long-Term Incentive Plan or any part of the plan from time to time, including increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. As of March 5, 2002, aggregate outstanding grants of approximately 679,000 restricted units have been made to employees of our general partner. Grants made include 165,000 restricted units to executive officers as a group. Additional grants of approximately 288,000 restricted units have been approved, with vesting in 25% increments when the quarterly distribution reaches $0.525, $0.575 and $0.625 ($2.10, $2.30 and $2.50 annualized), and the criteria for the remaining 25% is yet to be determined. These grants include approximately 203,000 restricted units to executive officers of the general partner. The Compensation Committee of the general partner may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine. Restricted units granted to employees during the subordination period, although additional vesting criteria may sometimes apply, will vest only after, and in the same proportions as, the conversion of the subordinated units to common units. Grants made to non-employee directors of our general partner are eligible to vest prior to termination of the subordination period. In 2000, the three non-employee directors of our former general partner were each granted 5,000 restricted units. These units vested in connection with the consummation of the General Partner Transition.

If a grantee terminates employment or membership on the board for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. Whether we satisfy vested units with purchases or by new issuances, the vesting will result in a compensation charge to us. Following the subordination period, the Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units.

The subordination period (as defined in the partnership agreement) will end if certain financial tests are met for three consecutive four-quarter periods (the "testing period"), but no sooner than December 31, 2003 (see Note 7).

The issuance of the common units pursuant to the restricted unit plan is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration will be paid to us by the plan participants upon receipt of the common units.

Unit Option Plan. The Unit Option Plan currently permits the grant of options covering common units. No grants have been made under the Unit Option Plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant. Unit options granted during the subordination period will become exercisable automatically upon, and in the same proportions as, the conversion of the subordinated units to common units, unless a later vesting date is provided.

Upon exercise of a unit option, our general partner will deliver common units acquired by it in the open market, or in private transactions, or use common units already owned by our general partner, or any combination of the foregoing. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants less any common units issued upon vesting of restricted units under the plan. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring such common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will remit to us the proceeds received by it from the optionee upon exercise of the unit option.

Certain employees and officers of the general partner have received grants of equity not associated with the Long-Term Incentive Plan described above, and for which we have no cost or reimbursement obligations (see Note 12).

Note 14 -- Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2001, are summarized below (in thousands):

2002	$ 6,774
2003	6,245
2004	6,340
2005	6,216
2006	4,458
Thereafter	5,595

Total lease expense incurred for 2001, 2000 and 1999 was $7.4 million, $6.7 million and $8.9 million, respectively. As is common within the industry and in the ordinary course of business, we have also entered into various operational commitments and agreements related to pipeline operations and to marketing, transportation, terminalling and storage of crude oil and liquefied petroleum gas.

From 1994 to 1997 (prior to our acquisition in 1999), our Venice, Louisiana terminal experienced several releases of crude oil and jet fuel into the soil. The Louisiana Department of Environmental Quality has been notified of the releases. Marathon Ashland has performed some soil remediation related to the releases and retained liability for these conditions. The extent of the contamination at the sites is uncertain and there is a potential for groundwater contamination. We do not expect expenditures related to this terminal to be material, although we can provide no assurances in that regard.

During 1997, the All American Pipeline experienced a leak in a segment of its pipeline in California that resulted in an estimated 12,000 barrels of crude oil being released into the soil. Immediate action was taken to repair the pipeline leak, contain the spill and to recover the released crude oil. We have expended approximately $0.4 million to date in connection with this spill and do not expect any additional expenditures to be material to the financial statements, although we can provide no assurances in that regard.

Prior to being acquired by our predecessor in 1996, the Ingleside Terminal experienced releases of refined petroleum products into the soil and groundwater underlying the site due to activities on the property. We are undertaking a voluntary state-administered remediation of the contamination on the property to determine the extent of the contamination. We have proposed extending the scope of our study and are awaiting the state's response. We have spent approximately $0.1 million to date in investigating the contamination at this site. We do not anticipate the total additional cost related to this site to exceed $0.3 million, although no assurance can be given that the actual cost could not exceed such estimate.

Litigation

Texas Securities Litigation. On November 29, 1999, a class action lawsuit was filed in the United States District Court for the Southern District of Texas entitled Di Giacomo v. Plains All American Pipeline, L.P., et al. The suit alleged that Plains All American and certain of our former general partner's officers and directors violated federal securities laws, primarily in connection with unauthorized trading by a former employee. An additional nineteen cases were filed in the Southern District of Texas, some of which named our former general partner and Plains Resources as additional defendants. All of the federal securities claims were consolidated into two actions. The first consolidated action is that filed by purchasers of Plains Resources' common stock and options, and is captioned Koplovitz v. Plains Resources Inc., et al. The second consolidated action is that filed by purchasers of our common units, and is captioned Di Giacomo v. Plains All American Pipeline, L.P., et al. Plaintiffs alleged that the defendants were liable for securities fraud violations under Rule l0b-5 and Section 20(a) of the Securities Exchange Act of 1934 and for making false registration statements under Sections 11 and 15 of the Securities Act of 1933.

We and Plains Resources reached an agreement with representatives for the plaintiffs for the settlement of all of the class actions, and in January 2001, we deposited approximately $30.0 million under the terms of the settlement agreement. The total cost of the settlement to us and Plains Resources, including interest and expenses and after insurance reimbursements, was $14.9 million. Of that amount, $1.0 million was allocated to Plains Resources by agreement between special independent committees of the board of directors of our former general partner and the board of directors of Plains Resources. All such amounts were reflected in our financial statements at December 31, 2000. The settlement was approved by the court on December 19, 2001. The order became final on January 18, 2002. The settlement agreement does not affect the Texas Derivative Litigation and Delaware Derivative Litigation described below.

Delaware Derivative Litigation. On December 3, 1999, two derivative lawsuits were filed in the Delaware Chancery Court, New Castle County, entitled Susser v. Plains All American Inc., et al and Senderowitz v. Plains All American Inc., et al. These suits, and three others which were filed in Delaware subsequently, named our former general partner, its directors and certain of its officers as defendants, and allege that the defendants breached the fiduciary duties that they owed to Plains All American Pipeline, L.P. and its unitholders by failing to monitor properly the activities of its employees. The court consolidated all of the cases under the caption In Re Plains All American Inc. Shareholders Litigation, and has designated the complaint filed in Susser v. Plains All American Inc. as the complaint in the consolidated action.

The plaintiffs in the Delaware derivative litigation seek, among other things, to cause the defendants to account for all losses and damages allegedly sustained by Plains All American from the unauthorized trading losses; to establish and maintain effective internal controls ensuring that our affiliates and persons responsible for our affairs do not engage in wrongful practices detrimental to Plains All American; and to pay for the plaintiffs' costs and expenses in the litigation, including reasonable attorneys' fees, accountants' fees and experts' fees.

We have agreed with the plaintiffs to settle the Delaware litigation for approximately $1.1 million. On March 6, 2002, the Delaware court approved the settlement.

Texas Derivative Litigation. On July 11, 2000, a derivative lawsuit was filed in the United States District Court of the Southern District of Texas entitled Fernandes v. Plains All American Inc., et al, naming our former general partner, its directors and certain of its officers as defendants. This lawsuit contains the same claims and seeks the same relief as the Delaware derivative litigation, described above. We have reached an agreement in principle with the plaintiffs, subject to approval by the District Court, to settle the Texas litigation for approximately $112,500.

Other. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Note 15 -- Quarterly Financial Data (Unaudited) (in thousands, except per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2001					
Revenues	$ 1,520,124	$ 1,586,617	$ 2,191,310	$ 1,570,164	$ 6,868,215
Gross margin	32,730	36,387	39,644	33,500	142,261
Operating income	19,071	14,843	22,945	14,509	71,368
Income before extraordinary item and cumulative effect of accounting change	12,507	7,067	15,161	8,936	43,671
Cumulative effect of accounting change	508	-	-	-	508
Net income	13,015	7,067	15,161	8,936	44,179
Income per limited partner unit before extraordinary item and cumulative effect of accounting change (1)	0.36	0.19	0.38	0.20	1.12
Cumulative effect of accounting change	0.01	-	-	-	0.01
After extraordinary item (1)	0.37	0.19	0.38	0.20	1.13
Cash distributions per common unit (2)	$ 0.475	$ 0.500	$ 0.513	$ 0.513	$ 2.000
2000					
Revenues	$ 2,002,507	$ 1,481,834	$ 1,555,863	$ 1,600,983	$ 6,641,187
Gross margin	36.552	32.774	25.960	32.434	127.720
Operating income	17,788	20,164	10,700	13,724	62,376
Income before extraordinary item and cumulative effect of accounting change	64,300	17,063	4,516	6,770	92,649
Extraordinary item	(4,145)	(11,002)	-	-	(15,147)
Net income	60,155	6,061	4,516	6,770	77,502
Income per limited partner unit before extraordinary item and cumulative effect of accounting change	1.83	0.49	0.13	0.19	2.64
Extraordinary item	(0.12)	(0.32)	-	-	(0.44)
Net income per limited partner unit	1.71	0.17	0.13	0.19	2.20
Cash distributions per common unit (2)	$ 0.450	$ 0.463	$ 0.463	$ 0.463	$ 1.839

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(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Represents cash distributions declared per common unit for the period indicated. Distributions are paid in the following calendar quarter.

Note 16 -- Operating Segments

Our operations consist of two operating segments: (1) Pipeline Operations - engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; (2) Marketing, Gathering, Terminalling and Storage Operations - engages in purchases and resales of crude oil and liquified petroleum gas at various points along the distribution chain and the leasing of certain terminalling and storage assets. We evaluate segment performance based on gross margin, gross profit and income (loss) before extraordinary items and cumulative effect of accounting change.

The following table summarizes segment revenues, gross margin, gross profit and income (loss) before extraordinary items and cumulative effect of accounting change (in thousands):

	Pipeline	Marketing, Gathering, Terminalling & Storage	Total
Twelve Months Ended December 31, 2001			
Revenues:			
External Customers	$ 339,852	$ 6,528,363	$ 6,868,215
Intersegment (a)	17,528	2,046	19,574
Other revenue	53	348	401
Total revenues of reportable segments	$ 357,433	$ 6,530,757	$ 6,888,190
Gain on sale of assets	$ 984	$ -	$ 984
Segment gross margin (b)	71,322	70,939	142,261
Segment gross profit (c)	65,110	36,306	101,416
Income allocated to reportable segments (d)	39,494	9,918	49,412
Noncash compensation expense	n/a	n/a	5,741
Income before extraordinary item and cumulative effect of accounting change	$ n/a	$ n/a	$ 43,671
Interest expense	10,667	18,415	29,082
Depreciation and amortization	15,983	8,324	24,307

Capital expenditures	11,035	30,204	41,239
Total assets	472,324	788,927	1,261,251

Table continued on following page

	Pipeline	Marketing, Gathering, Terminalling & Storage	Total
Twelve Months Ended December 31, 2000			
Revenues:			
External Customers	$ 505,712	$ 6,135,475	$ 6,641,187
Intersegment (a)	68,745	-	68,745
Other revenue	9,045	1,731	10,776
Total revenues of reportable segments	$ 583,502	$ 6,137,206	$ 6,720,708
Gain on sale of assets	$ 48,188	$ -	$ 48,188
Segment gross margin (b)	51,787	75,933	127,720
Segment gross profit (c)	49,996	39,992	89,988
Income allocated to reportable segments (d)	94,461	1,277	95,738
Noncash compensation expense	n/a	n/a	3,089
Income before extraordinary item and cumulative effect of accounting change	$ n/a	$ n/a	$ 92,649
Interest expense	5,738	22,953	28,691
Depreciation and amortization	7,030	17,493	24,523
Capital expenditures	1,544	11,059	12,603
Total assets	324,751	561,050	885,801
Twelve Months Ended December 31, 1999			
Revenues:			
External Customers	$ 854,377	$ 10,056,046	$ 10,910,423
Intersegment (a)	131,445	-	131,445
Other revenue	195	763	958
Total revenues of reportable segments	$ 986,017	$ 10,056,809	$ 11,042,826
Segment gross margin (b)	$ 58,001	$ (114,127)	$ (56,126)
Segment gross profit (c)	55,384	(133,708)	(78,324)
Income (loss) allocated to reportable segments (d)	46,075	(146,877)	(100,802)
Noncash compensation expense	n/a	n/a	1,013
Income (loss) before extraordinary item and cumulative effect of accounting change	$ n/a	$ n/a	$ (101,815)
Interest expense	13,572	7,567	21,139
Depreciation and amortization	10,979	6,365	17,344
Capital expenditures	69,375	119,911	189,286
Total assets	524,438	698,599	1,223,037

(a) Intersegment sales were conducted on an arm's length basis.

(b) Gross margin is calculated as revenues less cost of sales and operations expense. The 2001 gross margin includes the impact of the $5.0 million inventory valuation adjustment.

(c) Gross profit is calculated as revenues less costs of sales and operations expenses and general and administrative expenses, excluding noncash compensation expense.

(d) Excludes noncash compensation expense, as it is not allocated to the reportable segments.

Prior to 2001, all of our revenues were derived from, and our assets located in, the United States. During 2001, we expanded into Canada (see Note 4). Set forth below is a table of 2001 revenues and long lived assets attributable to these geographic areas (in thousands):

Revenues	
United States	$ 6,149,788
Canada	$ 718,427
Long Lived Assets	
United States	$ 567,551
Canada	$ 188,207

Note 17 -- Subsequent Events

Acquisitions

In March 2002, we completed the acquisition of substantially all of the domestic crude oil pipeline, gathering, and marketing assets of Coast Energy Group and Lantern Petroleum, divisions of Cornerstone Propane Partners, L.P. for approximately $8.2 million in cash plus transaction costs. The principal assets acquired, which are located in West Texas, include several gathering lines, crude oil contracts and a small truck and trailer fleet.

In February 2002, we acquired an approximate 22% equity interest in Butte Pipe Line Company from Murphy Ventures, a subsidiary of Murphy Oil Corporation. The total cost of the acquisition, including various transaction and related expenses, was approximately $8.0 million. Butte Pipe Line Company owns the 373-mile Butte Pipeline System that runs from Baker, Montana, to Guernsey, Wyoming. The Butte Pipeline System, principally a mainline system, transported approximately 60,000 barrels per day of crude oil at the time of acquisition. The remaining 78% interest in the Butte Pipe Line Company is owned by Equilon Pipeline Company LLC.