PART II

Item 5. *Market For the Registrant's Common Units and Related Unitholder Matters*

The common units, excluding the Class B common units, are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 17, 2004, the closing market price for the common units was $32.12 per unit and there were approximately 30,000 record holders and beneficial owners (held in street name). As of February 17, 2004, there were 57,162,638 common units outstanding and 1,307,190 Class B common units outstanding. The number of common units outstanding on this date includes the 10,029,619 common units that converted from Subordinated Units in November 2003 and February 2004.

The following table sets forth high and low sales prices for the common units and the cash distributions paid per common unit for the periods indicated:

	Common Unit Price Range		
	High	**Low**	**Cash Distributions(1)**
2002			
1st Quarter	$ 26.79	$ 23.60	$ 0.5250
2nd Quarter	27.30	24.60	0.5375
3rd Quarter	26.38	19.54	0.5375
4th Quarter	24.44	22.04	0.5375
2003			
1st Quarter	$ 26.90	$ 24.20	$ 0.5500
2nd Quarter	31.48	24.65	0.5500
3rd Quarter	32.49	29.10	0.5500
4th Quarter	32.82	29.76	0.5625

(1) Cash distributions are paid in the following calendar quarter.

The Class B common units are pari passu with common units with respect to quarterly 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 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, the Class B units have the same voting rights as the common units. As of February 17, 2004, there was one Class B unitholder.

Cash Distribution Policy

We distribute on a quarterly basis all of our available cash. Available cash generally means, for any of our fiscal quarters, all cash on hand at the end of the quarter less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

In addition to distributions on its 2% general partner interest, 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, our general partner is entitled, without duplication, 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. We paid $4.4 million to the general partner in incentive distributions in 2003. Our most recent quarterly distribution was $0.5625 per unit. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-term Debt."

See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters" for equity compensation plan information.

Item 6. *Selected Financial and Operating Data*

The historical financial information below for Plains All American Pipeline, L.P. was derived from our audited consolidated financial statements as of December 31, 2003, 2002, 2001, 2000 and 1999 and for the years ended December 31, 2003, 2002, 2001, 2000 and 1999. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(in millions except per unit data)				
Statement of operations data:					
Revenues	$ 12,589.8	$ 8,384.2	$ 6,868.2	$ 6,641.2	$ 10,910.4
Cost of sales and operations (excluding LTIP charge)	12,366.6	8,209.9	6,720.9	6,506.5	10,800.1
Unauthorized trading losses and related expenses	—	—	—	7.0	166.4
Inventory valuation adjustment	—	—	5.0	—	—
LTIP charge—operations[1]	5.7	—	—	—	—
General and administrative expenses (excluding LTIP charge)	50.0	45.7	46.6	40.8	23.2
LTIP charge—general and administrative[1]	23.1	—	—	—	—
Depreciation and amortization	46.8	34.0	24.3	24.5	17.3
Restructuring expense	—	—	—	—	1.4
Total costs and expenses	12,492.3	8,289.6	6,796.8	6,578.8	11,008.4
Gain on sale of assets	0.6	—	1.0	48.2	16.4
Operating income	98.2	94.6	72.4	110.6	(81.6)
Interest expense	(35.2)	(29.1)	(29.1)	(28.7)	(21.1)
Interest income and other, net[2]	(3.6)	(0.2)	0.4	(4.4)	0.9
Income (loss) from continuing operations before cumulative effect of accounting change	$ 59.4	$ 65.3	$ 43.7	$ 77.5	$ (101.8)
Basic net income (loss) per limited partner unit before cumulative effect of accounting change	$ 1.01	$ 1.34	$ 1.12	$ 2.64	$ (3.16)
Diluted net income (loss) per limited partner unit before cumulative effect of accounting change	$ 1.00	$ 1.34	$ 1.12	$ 2.64	$ (3.16)
Basic weighted average number of limited partner units outstanding	52.7	45.5	37.5	34.4	31.6
Diluted weighted average number of limited partner units					

outstanding	53.4	45.5	37.5	34.4	31.6

Table continued on following page.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(in millions except per unit data)				
Balance sheet data (at end of period):					
Working capital surplus (deficit)	$ (68.9)	$ (34.3)	$ 52.9	$ 47.1	$ 101.5
Total assets	2,095.6	1,666.6	1,261.2	885.8	1,223.0
Total long-term debt[3][4]	519.0	509.7	354.7	320.0	424.1
Total debt[4]	646.2	609.0	456.2	321.3	482.8
Partners' capital	746.7	511.6	402.8	214.0	193.0

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Other data (in millions):					
Maintenance capital expenditures	$ 7.6	$ 6.0	$ 3.4	$ 1.8	$ 1.7
Net cash provided by (used in) operating activities	68.5	173.9	(30.0)	(33.5)	(71.2)
Net cash provided by (used in) investing activities	(225.3)	(363.8)	(249.5)	211.0	(186.1)
Net cash provided by (used in) financing activities	157.2	189.5	279.5	(227.8)	305.6
Operating Data:					
Volumes (thousands of barrels per day, unless otherwise noted)[5][6]:					
Pipeline segment:					
Tariff activities					
All American	59	65	69	74	103
Basin	263	93	N/A	N/A	N/A
Other domestic	299	219	144	130	61
Canada	203	187	132	N/A	N/A
Pipeline margin activities	78	73	61	60	54
Total	902	637	406	264	218
Gathering, marketing, terminalling and storage segment:					
Lease gathering	437	410	348	262	265
Bulk purchases	90	68	46	28	138
Total	527	478	394	290	403
Cushing Terminal throughput	208	110	94	59	72
Cushing Terminal storage leased to third parties (thousands of barrels per month)	1,165	1,067	2,136	1,437	1,743

(1)

Compensation expense related to our Long Term Incentive Plan ("LTIP"), see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Vesting of Restricted Units under Long-Term Incentive Plan."

(2)

The 2000 period includes $15.1 million related to a loss on early extinguishment of debt previously classified as an extraordinary item. Effective with the issuance of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in April 2002, such items should now be shown as impacting income from continuing operations.

(3) Includes current maturities of long-term debt of $9.0 million, $3.0 million, and $50.7 million at December 31, 2002, 2001 and 1999, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(4) The 1999 amount includes a $114.0 million note payable to our former general partner.

(5) Prior period volume amounts have been adjusted for consistency of comparison between years.

(6) Volume associated with acquisition represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

Items Impacting Comparability of Financial Results

In our internal evaluation of financial and operating results, we consider the effects of certain items that we believe impact the comparability of such results between reporting periods. In the table below, we have included a detailed listing of such items and we believe that this presentation, when considered in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations", provides additional information useful to a thorough analysis of our results of operations and financial condition.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(in millions)				
Noncash SFAS 133 adjustment	$ 0.4	$ 0.3	$ 0.2	$ —	$ —
LTIP charge	(28.8)	—	—	—	—
Loss on refinancing of debt	(3.3)	—	—	(15.1)	(1.5)
Write-off of deferred acquisition-related costs	—	(1.0)	—	—	—
Noncash reserve for potential environmental obligations	—	(1.2)	—	—	—
Noncash mark-to-market inventory charge	—	—	(5.0)	—	—
Noncash compensation expense	—	—	(5.7)	(3.1)	(1.0)
Noncash reserve for doubtful accounts	—	—	(3.0)	(5.0)	—
Gain on sales of assets	—	—	1.0	48.2	16.4
Noncash cumulative effect of accounting change	—	—	0.5	—	—
Unauthorized trading losses and related expenses	—	—	—	(7.0)	(166.4)
Gain on interest rate swap	—	—	—	9.7	—
Restructuring charge	—	—	—	—	(1.4)
Total of items impacting comparability	$ (31.7)	$ (1.9)	$ (12.0)	$ 27.7	$ (153.9)

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion of our financial condition and results of our operations should be read in conjunction with our historical consolidated financial statements and accompanying notes. For more detailed information regarding the basis of presentation for the following financial information, see the "Notes to the Consolidated Financial Statements."

Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership (the "Partnership") formed in September of 1998. See Items 1 and 2. "Business and Properties—Organizational History." Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquified petroleum gas and other petroleum products collectively as "LPG." We own an extensive network in the United States and Canada of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs.

In order to better understand the financial statements discussed herein, it is important to understand the basic nature of our two operating segments as well as the magnitude of the impact of our acquisition program from inception. Our operations are conducted primarily in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan and consist of two operating segments: (i) Pipeline Operations and (ii) Gathering, Marketing, Terminalling and Storage Operations ("G, M, T & S"). Our revenues from pipeline operations generally derive from the transportation of crude oil for a fee and leases of pipeline capacity to third parties, as well as from barrel exchanges and buy/sell arrangements. Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG plus the sale of additional barrels through buy/sell arrangements entered into to enhance the margins of the gathered and bulk-purchased volumes. We discuss the fundamental drivers of each of these operating segments in greater detail below under "—Analysis of Operating Segments." The significant impact of our acquisition program on our reported financial results is discussed under "—Acquisitions" immediately below.

Acquisitions

We completed a number of acquisitions in 2003, 2002 and 2001 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase price was allocated, in accordance with the purchase method of accounting. We adopted SFAS No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001. Our ongoing acquisition activity is discussed further in "Liquidity and Capital Resources" below.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration of approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. The acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with a portion of the proceeds from our equity issuances and the issuance of senior notes. See "—Liquidity and Capital Resources." The businesses acquired during 2003 impacted our results of operations subsequent to the effective date of each acquisition as indicated below. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. With the exception of $0.5 million that was allocated to goodwill and other intangible assets and $4.7 million associated with crude oil linefill and working inventory, the remaining aggregate purchase price was allocated to property and equipment. The following table details our 2003 acquisitions (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Red River Pipeline System	02/01/03	$ 19.4	Pipeline
Iatan Gathering System	03/01/03	24.3	Pipeline
Mesa Pipeline Facility	05/05/03	2.9	Pipeline
South Louisiana Assets[1]	06/01/03	13.4	Pipeline/G,M,T,&S
Alto Storage Facility	06/01/03	8.5	G,M,T&S
Iraan to Midland Pipeline System	06/30/03	17.6	Pipeline
ArkLaTex Pipeline System	10/01/03	21.3	Pipeline
South Saskatchewan Pipeline System	11/01/03	47.7	Pipeline
Atchafalaya Pipeline System[2]	12/01/03	4.4	Pipeline
Total 2003 Acquisitions		$ 159.5	

(1) Includes a 33.3% interest in Atchafalaya Pipeline L.L.C.

(2) Includes two acquisitions each for 33.3% interests in Atchafalaya Pipeline L.L.C.

2002 Acquisitions

Shell West Texas Assets. On August 1, 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition") for approximately $324 million. The primary assets included in the transaction are interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. The entire purchase price was allocated to property and equipment.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport the crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The Permian Basin has long been one of the most stable crude oil producing regions in the United States, dating back to the 1930s. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin Pipeline System is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial Sale of Rancho Pipeline System."

For more information on this transaction, as well as historical financial information on the businesses acquired and pro forma financial information reflecting the acquisition of the businesses, please refer to our Form 8-K dated August 9, 2002, which was filed with the Securities and Exchange Commission.

Other 2002 Acquisitions. During February and March of 2002, we completed two other acquisitions for aggregate consideration totaling $15.9 million, with effective dates of February 1, 2002 and March 31, 2002, respectively. These acquisitions include an equity interest in a crude oil pipeline company and crude oil gathering and marketing assets.

2001 Acquisitions

CANPET Energy Group. In July 2001, we acquired the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company (the "CANPET acquisition"), for approximately $24.6 million plus excess inventory at the closing date of approximately $25.0 million. A portion of the purchase price, payable in common units or cash, at our option, was deferred subject to various performance standards being met. As of December 31, 2003, we determined that it was beyond a reasonable doubt that the performance standards were met and we recorded additional consideration of $24.3 million, (see Note 7—"Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements"), resulting in aggregate consideration of approximately $73.9 million. The deferred consideration was recorded as goodwill.

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 LPGs. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States. The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Inventory	$	28.1
Goodwill		35.4
Intangible assets (contracts)		1.0
Pipeline linefill		4.3
Crude oil gathering, terminalling and other assets		5.1
Total	$	73.9

Murphy Oil Company Ltd. Midstream Operations. In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $158.4 million in cash after post-closing adjustments, including financing and transaction costs (the "Murphy acquisition"). Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase price included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate 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, and 121 trailers used primarily for crude oil transportation. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States.

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 acquisition, these volumes averaged 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 purchase price, as adjusted post-closing, was allocated as follows (in millions):

Crude oil pipeline, gathering and terminal assets	$	148.0
Pipeline linefill		7.6
Net working capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
Total	$	158.4

Other 2001 Acquisitions. In December 2001, we consummated the acquisition of the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs. The entire purchase price was allocated to property and equipment. The system further expands our market in Canada.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting policies that we have identified are discussed below.

Depreciation, Amortization and Impairment of Long-Lived Assets

We calculate our depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are put into service, we make estimates with respect to useful lives that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Additionally, we assess our long-lived assets for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in our business plans, a change in the extent or manner in which a long-lived asset is being used or in its physical condition, or a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge would be recorded for the excess of the carrying value of the asset over its fair value. Determination as to whether and how much an asset is impaired would necessarily involve numerous management estimates. Any impairment reviews and calculations would be based on assumptions that are consistent with our business plans and long-term investment decisions.

Allowance for Doubtful Trade Accounts Receivable

The majority of our trade accounts receivable relate to our gathering and marketing activities and can generally be described as high volume and low margin activities. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered, received 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. Based on these analyses, we have established an allowance for doubtful trade accounts receivable and consider the reserve adequate, however, there is no assurance that actual amounts will not vary significantly from estimated amounts.

Purchase and Sales Accruals

We routinely make accruals for both purchases and sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. In situations where we are required to make mark-to-market estimates pursuant to SFAS 133, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. A portion of the estimates we use are based on internal models or models of third parties because they are not quoted on a national market. Additionally, values may vary among different models and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total revenues are based on estimates derived from these models. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Liability and Contingency Accruals

We accrue reserves for contingent liabilities including, but not limited to, environmental remediation, insurance claims and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. These estimates will be increased or decreased as additional information is obtained or resolution is achieved. We also make accruals for potential payments under our Long-Term Incentive Plan ("LTIP") when we determine that vesting of the units is probable. The aggregate amount of the actual charge to expense will be determined by the unit price on the date vesting occurs (or, in some cases, the average unit price for a range of dates) multiplied by the number of units, plus our share of associated employment taxes. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Determination of Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets

In conjunction with each acquisition, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, in conjunction with the adoption of SFAS 141, we are required to recognize intangible assets separately from goodwill. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. The impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Intangible assets with finite lives are amortized over the estimated useful life determined by management. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

In June 2001, the FASB issued SFAS No. 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 the cost for asset retirement 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. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we can reasonably determine the settlement dates.

Results of Operations

Summary of Three Years Ended December 31, 2003

Our operations consist of two operating segments: (1) our Pipeline Operations, through which we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities; and (2) our Gathering, Marketing, Terminalling and Storage Operations, through which we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets.

For the year ended December 31, 2003, we reported consolidated net income of $59.4 million on total revenues of $12.6 billion compared to net income for the same period in 2002 and 2001 of $65.3 million and $44.2 million on total revenues of $8.4 billion and $6.9 billion, respectively. Included in the results of operations for 2003, 2002 and 2001 are certain items that impact the comparability between periods, which are discussed further below. Excluding these items, our operating results reflect year over year growth in both our Pipeline Operations segment and our Gathering, Marketing, Terminalling and Storage Operations segment. The growth reflects the impact on our operations of the acquisition and integration of the businesses discussed above, as well as, the successful completion of various capital expansion projects.

Items Impacting Comparability

During the first quarter of 2003, new Securities and Exchange Commission regulations regarding the use of non-GAAP financial measures became effective. As a result of our efforts to comply with these new regulations, we have made certain changes to the content and presentation of information in Management's Discussion and Analysis of Financial Condition and Results of Operations. Internally, we consider in our analysis of operating results the impact of items that we believe impact comparability between periods; however, to comply with the new regulations, we have omitted certain adjustments and reconciliations related to these items that have been presented in the past. We have also changed the format of certain tables presented in the discussion of our results of operations. In addition, certain reclassifications have been made to the prior period presentations to conform to current period presentation. Where appropriate, we have noted that reported results include the effects of items we consider to impact comparability between periods. Overall, we believe the discussion and presentation provides an accurate and thorough analysis of our results of operations and financial condition. Additionally, we maintain on our website (www.paalp.com) a reconciliation of all non-GAAP financial information in our earnings releases and other communications with security holders to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" header at the top of our home page and then click on the "Non-GAAP Reconciliation" section on the Investor Relations page.

The following is a summary of items that we believe impact comparability between periods and that we consider separately when we evaluate our results for performance against expectations, public guidance and trend analysis. Following that summary is a more detailed discussion of the results of operations of each segment. The items discussed below are included in net income in the period indicated and impact the comparability between periods as shown:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Items Impacting Comparability			
Noncash SFAS 133 adjustment	$ 0.4	$ 0.3	$ 0.2
LTIP charge	(28.8)	—	—
Loss on refinancing of debt	(3.3)	—	—
Write-off of deferred acquisition-related costs	—	(1.0)	—
Noncash reserve for potential environmental obligations	—	(1.2)	—
Noncash mark-to-market inventory charge	—	—	(5.0)
Noncash compensation expense	—	—	(5.7)

Noncash reserve for doubtful accounts	—	—	(3.0)
Gain on sales of assets	—	—	1.0
Noncash cumulative effect of accounting change	—	—	0.5
Total of items impacting comparability	$ (31.7)	$ (1.9)	$ (12.0)

The following is a discussion of each of the items that impacted our results of operations. Further discussion of each of the items impacting comparability for the three years ended December 31, 2003, is included in the applicable portion of the results of operations discussion.

- *Noncash Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" Adjustment*—SFAS 133 requires that changes in derivative instruments' fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to Other Comprehensive Income, or "OCI," and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. The majority of instruments we are required to mark-to-market at the end of each quarterly period pursuant to SFAS 133 nonetheless serve as economic hedges that offset future physical positions not reflected in current results. Therefore, we believe mark-to-market adjustments to net income required under SFAS 133 do not provide a complete depiction of the economic substance of the transaction, as it only represents the derivative side of these transactions and does not take into account the offsetting physical position. In addition, the impact will vary from quarter to quarter based on market prices at the end of the quarter, which are impossible for us to control or forecast, and the SFAS 133 adjustments will reverse in future periods. Accordingly, when we evaluate our results internally for performance against expectations, public guidance and trend analysis, we exclude the non-cash, mark-to-market impact of SFAS 133. We present the impact of the SFAS 133 adjustments because we believe such amounts affect the comparison of the fundamental operating results for the periods presented. We reported SFAS 133 gains of $0.4 million, $0.3 million and $0.2 million, for the three years ending December 31, 2003, respectively. Such annual amounts vary by only approximately $0.1 million per year between consecutive periods (2001 compared to 2002 and 2002 compared to 2003). However, in the eight quarterly comparisons within those three years (four quarters of 2001 compared to four quarters of 2002,
- then four quarters of 2002 compared to four quarters of 2003), variances were $0.9 million or higher in seven of the eight comparable quarterly periods and ranged as high as $3.8 million. (e.g., the first quarter of 2001 compared to 2002 and the first quarter of 2002 compared to 2003). Management believes such quarterly variances underscore the importance of highlighting the impact of these mark-to-market adjustments.
- *Long-Term Incentive Plan charge*—Under generally accepted accounting principles, we are required to recognize an expense when vesting of LTIP units becomes probable as determined by management at the end of the period. Our results of operations include a charge of $28.8 million in the year ended December 31, 2003. See "—Outlook—LTIP vesting" and Note 11—"Long-Term Incentive Plans" in the "Notes to the Consolidated Financial Statements."
- *Loss on refinancing of debt*—During the fourth quarter of 2003 we completed the refinancing of our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purchase of hedged crude oil (See "—Other Income and Expenses—Other"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.
- *Additional 2002 Items Impacting Comparability*—Our 2002 results of operations also include charges of $1.0 million related to the write-off of deferred acquisition-related costs (See "—Other Income and Expenses—Unallocated G&A Expenses") and a noncash charge of $1.2 million associated with the establishment of a reserve for environmental obligations (See "—Pipeline Operations—Segment Margin").

Additional 2001 Items Impacting Comparability—Our 2001 results of operations also include (i) a $5.0 million noncash writedown of operating crude oil inventory in the fourth quarter of 2001 (See Note 2 "Summary of Significant Accounting Policies" in the "Notes to Consolidated Financial Statements"), (ii) a $5.7 million noncash charge related to incentive compensation (See "—Other Expenses—Unallocated G&A Expenses"), (iii) a $3.0 million reserve for receivables, (iv) a $1.0 million gain on sale of assets and (v) a $0.5 noncash gain as a cumulative effect of accounting change resulting from the adoption of SFAS 133.

Analysis of Operating Segments

We evaluate segment performance based on (i) segment margin (revenues less purchases and operating expenses), (ii) segment profit (segment margin less General and Administrative ("G&A") expenses) and (iii) maintenance capital. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. The following table reflects our results of operations for each segment:

	Pipeline Operations	Gathering, Marketing, Terminalling & Storage Operations
	(in millions)	
Year Ended December 31, 2003[1]		
Revenues	$ 658.6	$ 11,985.6
Purchases	487.1	11,799.8
Operating expenses (excluding LTIP charge)	60.9	73.3
LTIP charge—operations	1.4	4.3
Segment margin	109.2	108.2
General and administrative expenses (excluding LTIP charge)[2]	18.3	31.6
LTIP charge—general and administrative	9.6	13.5
Segment profit	$ 81.3	$ 63.1
Noncash SFAS 133 impact[3]	$ —	$ 0.4
Maintenance capital	$ 6.4	$ 1.2
Year Ended December 31, 2002[1]		
Revenues	$ 486.2	$ 7,921.8
Purchases	362.2	7,765.1
Operating expenses	40.1	66.3
Segment margin	83.9	90.4
General and administrative expenses[2]	13.2	31.5
Segment profit	$ 70.7	$ 58.9
Noncash SFAS 133 impact[3]	$ —	$ 0.3
Maintenance capital	$ 3.4	$ 2.6

Table continued on following page.

Year Ended December 31, 2001[1]		
Revenues	$ 357.4	$ 6,528.3
Purchases	266.7	6,383.6
Operating expenses	19.4	73.7
Segment margin	71.3	71.0
General and administrative expenses[2]	12.4	28.5
Segment profit	$ 58.9	$ 42.5
Noncash SFAS 133 impact[3]	$ —	$ 0.2
Maintenance capital	$ 0.5	$ 2.9

(1)
Revenues and purchases include intersegment amounts.

(2)
G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.

(3)
Amounts related to SFAS 133 are included in revenues and impact segment margin and segment profit.

Pipeline Operations

As of December 31, 2003, we owned and operated approximately 7,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third-party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment margin generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable costs of operating the pipeline. Segment margin from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Year ended December 31,		
	2003	**2002**	**2001**
Operating Results[1] (in millions)			
Revenues			
Tariff activities	$ 153.3	$ 103.7	$ 69.4
Pipeline margin activities	505.3	382.5	288.0
Total pipeline operations revenues	658.6	486.2	357.4
Costs and Expenses			
Pipeline margin activities purchases	487.1	362.2	266.7
Operating expenses (excluding LTIP charge)	60.9	40.1	19.4
LTIP charge — operations	1.4	—	—
Segment margin	109.2	83.9	71.3
General and administrative expenses (excluding LTIP charge)[2]	18.3	13.2	12.4

LTIP charge — general and administrative	9.6	—	—
Segment profit	$ 81.3	$ 70.7	$ 58.9
Maintenance capital	$ 6.4	$ 3.4	$ 0.5
Average Daily Volumes (thousands of barrels per day)[(3)(4)]			
Tariff activities			
All American	59	65	69
Basin	263	93	—
Other domestic	299	219	144
Canada	203	187	132
Total tariff activities	824	564	345
Pipeline margin activities	78	73	61
Total	902	637	406

(1) Revenues and purchases include intersegment amounts.

(2) G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

(4) Prior period volumes have been adjusted for consistency of comparison between years.

Total average daily volumes transported were approximately 902,000 barrels per day for the year ended December 31, 2003, compared to 637,000 barrels per day and 406,000 barrels per day for the years ended December 31, 2002 and 2001, respectively. As discussed above, we have completed a number of acquisitions during 2003 and 2002 that have impacted the results of operations herein. The following table reflects our total average daily volumes from our tariff activities by year of acquisition for comparison purposes:

	Year Ended December 31,		
	2003	**2002**	**2001**
	(thousands of barrels per day)		
Tariff activities[(1)(2)]			
2003 acquisitions	82	—	—
2002 acquisitions	344	171	—
2001 acquisitions	200	193	134
All other pipeline systems	198	200	211
Total tariff activities average daily volumes	824	564	345

(1) Volumes associated with acquisitions represent weighted average daily amounts for the number of days we actually owned the assets over the total days in the period.

(2) Prior period volumes have been adjusted for consistency of comparison between years.

The increase in average daily volumes from our tariff activities to 824,000 barrels per day in 2003 from 564,000 barrels per day and 345,000 barrels per day in 2002 and 2001, respectively, resulted primarily from our acquisition activities discussed above. The following discussion explains year-to-year variances based on the comparison of volumes in the table above.

2003 Acquisitions—Approximately 82,000 barrels per day of the increase in 2003 volumes over 2002 volumes is related to systems acquired during 2003.

2002 Acquisitions—An additional 173,000 barrels per day of the increase in 2003 resulted from the inclusion of assets acquired in 2002 for the entire year in 2003 as compared to only a portion of 2002. The assets acquired in the Shell acquisition accounted for 171,000 barrels per day of this increase as increased barrels per day on the Basin Pipeline System and the Permian Basin Gathering System coupled with the impact of including a full year results in 2003 as compared to only five months in 2002 more than offset the decrease in barrels per day resulting from the shut-down of the Rancho Pipeline System (See Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial Sale of Rancho Pipeline System").

2001 Acquisitions—In addition, volumes on pipeline systems acquired in 2001 increased by approximately 7,000 barrels per day in the 2003 period as Canadian volumes benefited from the completion of capital expansion projects that allowed for additional volumes on certain pipelines. Barrels per day on these systems increased in the 2002 period as compared to the 2001 period primarily due to the inclusion of the Murphy acquisition for a full year in 2002 compared to only a portion of the year in 2001.

All other pipeline systems—Volumes on all other pipeline systems decreased approximately 2,000 barrels per day primarily because of a 6,000 barrel per day decrease in our All American tariff volumes and various other decreases totaling 4,000 barrels per day on several of our pipeline systems. The decrease in All American tariff volumes is attributable to a decline in California outer continental shelf ("OCS") production. Partially offsetting these decreases was an 8,000 barrel per day increase in our West Texas Gathering System volumes. Our West Texas Gathering System has benefited from the shutdown of the Rancho pipeline and also from temporary refinery problems that have diverted crude oil barrels from other systems. Volumes on all other pipeline systems decreased by approximately 11,000 barrels per day in 2002 as compared to 2001, primarily because of an approximate 4,000 barrel per day decrease in our All American tariff volumes and a 4,000 barrel per day decrease in our West Texas Gathering System volumes.

Revenues

Total revenues from our pipeline operations were approximately $658.6 million for the year ended December 31, 2003, compared to $486.2 million and $357.4 million for the years ended December 31, 2002 and 2001, respectively. The increase in revenues was primarily related to our pipeline margin activities, which increased by approximately $122.8 million in 2003. This increase was related to higher average crude oil prices coupled with increased volumes on our buy/sell arrangements on our San Joaquin Valley gathering system in 2003. However, this business is a margin business and although revenues and cost of sales are impacted by the absolute level of crude oil prices, there is a limited impact on segment margin. The increase in 2002 over 2001 also was primarily related to our pipeline margin activities on our San Joaquin Valley gathering system. Increased volumes and higher average prices on our buy/sell arrangements were the primary drivers of the increase.

Revenues from our tariff activities increased approximately 48% or $49.6 million in 2003 as compared to 2002. The following table reflects revenues from our tariff activities by year of acquisition for comparison purposes:

	Year Ended December 31,		
	2003	2002	2001
	(in millions)		
Tariff activities revenues[1]			
2003 acquisitions	$ 14.8	$ —	$ —
2002 acquisitions	54.2	23.1	—
2001 acquisitions	28.0	21.6	9.9

All other pipeline systems	56.3	59.0	59.5
Total tariff activities	$ 153.3	$ 103.7	$ 69.4

(1) Revenues include intersegment amounts.

The increase in revenues from our tariff activities to $153.3 million in 2003 from $103.7 million and $69.4 million in 2002 and 2001, respectively, resulted predominantly from our acquisition activities discussed above. The following discussion explains year-to-year variances based on the comparison of revenues in the table above.

2003 Acquisitions—Approximately $14.8 million of the increase in 2003 revenues over 2002 revenues is related to systems acquired during 2003.

2002 Acquisitions—An additional $31.1 million of the increase in 2003 revenues from our tariff activities resulted from the inclusion of assets acquired in 2002 for the entire year in 2003 as compared to only a portion of 2002. This increase was entirely related to the assets acquired in the Shell acquisition as increased revenues on the Basin Pipeline System and the Permian Basin Gathering System coupled with the impact of including a full year results in 2003 as compared to only five months in 2002 more than offset the decrease in revenues resulting from the shut-down of the Rancho Pipeline System (See Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial Sale of Rancho Pipeline System").

2001 Acquisitions—In addition, revenues from 2001 acquisitions increased approximately $6.4 million in 2003 as compared to 2002. This increase predominately resulted from increased Canadian revenues of $6.5 million in the 2003 period primarily due to expanded capacity, higher tariffs and a $3.4 million favorable exchange rate impact. The favorable exchange rate impact has resulted from a decrease in the Canadian dollar to U.S. dollar exchange rate to an average rate of 1.40 to 1 for the year ended December 31, 2003, from an average rate of 1.57 to 1 for the year ended December 31, 2002. Revenues from these systems increased to $21.6 million in 2002 from $9.9 million in 2001 primarily because of the inclusion of the Murphy acquisition for a full year in 2002 and increases in the tariff of certain pipeline systems acquired in the Murphy acquisition.

All other pipeline systems—Revenues from all other pipeline systems were relatively flat for all of the comparable periods as the decrease in volumes attributable to OCS production on our All American system (on which we receive the highest per barrel tariffs among our pipeline operations) was offset in each period by other increases, including increases in the tariffs for OCS volumes transported.

Segment Margin

Our pipeline operations segment margin increased 30% to approximately $109.2 million for the year ended December 31, 2003, from $83.9 million for the year ended December 31, 2002. Pipeline segment margin was approximately $71.3 million in 2001. The primary reasons for the increase in segment margin are discussed above and are also impacted by an increase in operating expenses to $62.3 million in 2003 from $40.1 million and $19.4 million in 2002 and 2001, respectively. The 2003 increase in expenses includes $1.4 million related to the accrual made for the probable vesting of unit grants under our LTIP and approximately $1.0 million related to a pipeline spill in Mississippi. The remaining increase is predominately related to our continued growth, primarily from acquisitions, coupled with higher utility costs. In addition, segment margin includes a $2.2 million favorable impact resulting from the decrease in the average Canadian dollar to U.S. dollar exchange rate for the 2003 period as compared to the 2002 period.

The increase in operating expenses in 2002 as compared to 2001 was primarily related to the acquisition of businesses in 2002 and late 2001 and the inclusion of the results of the Murphy acquisition for all of 2002 compared to only a portion of 2001. Our operating expense for the 2002 period also includes a $1.2 million noncash charge associated with the establishment of a liability for potential cleanup of environmental conditions associated with our 1999 acquisitions, based on additional information. This amount is approximately equal to the threshold amounts we must incur before the sellers' indemnities take effect. In many cases, the actual cash expenditure may not occur for ten years or more.

Segment Profit

G&A expenses were approximately $27.9 million in 2003, compared to approximately $13.2 million and $12.4 million in 2002 and 2001, respectively. The increase in 2003 is primarily a result of a $9.6 million accrual related to the probable vesting of unit grants under our LTIP. Additionally, the percentage of indirect costs allocated to the pipeline operations segment has increased in 2003 as our pipeline operations have grown. Including the impact of the items discussed above, segment profit was approximately $81.3 million for the year ended December 31, 2003, an increase of 15% as compared to the $70.7 million reported for the year ended December 31, 2002. Segment profit includes a $2.0 million favorable impact resulting from the decrease in the average Canadian-dollar to U.S.-dollar exchange rate for the 2003 period as compared to the 2002 period. The increase in G&A expenses in 2002 as compared to 2001 was partially due to increased costs from the assets acquired in the Murphy acquisition related to the inclusion of these assets for all of 2002 compared to only a portion of 2001.

Maintenance Capital

For the periods ended December 31, 2003, 2002 and 2001, maintenance capital expenditures were approximately $6.4 million, $3.4 million and $0.5 million, respectively for our pipeline operations segment. The increases between the years are related to our continued growth, primarily through acquisitions.

Gathering, Marketing, Terminalling and Storage Operations

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG plus the sale of additional barrels exchanged through buy/sell arrangements entered into to enhance the margins of the gathered and bulk-purchased volumes. Segment margin from our gathering and marketing activities is dependent on our ability to sell crude oil and LPG at a price in excess of our aggregate cost. These operations are margin businesses and are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and LPG and fluctuations in market-related indices. Accordingly, an increase or decrease in revenues is not necessarily an indication of segment performance.

We own and operate approximately 24.0 million barrels of above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Approximately 11.0 million barrels of our 24.0 million barrels of tankage is used primarily in our Gathering, Marketing, Terminalling and Storage Operations and the balance is used in our Pipeline Operations segment. On a stand alone basis, segment margin from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities.

As a result of completing our Phase II and III expansions at our Cushing facility, total Cushing tankage dedicated to our Gathering, Marketing, Terminalling and Storage Operations was approximately 1.5 million barrels greater in 2003 relative to 2002. A portion of such tankage was employed in hedging activities related to our gathering and marketing activities in 2003 and the latter portion of 2002.

During 2003, market conditions were extremely volatile as a confluence of several events caused the NYMEX benchmark price of crude oil to fluctuate widely with prices ranging from as high as $39.99 per barrel to as low as $25.04 per barrel. For much of the first eight months of 2003, the crude oil market was in steep backwardation. Although the crude oil market was characterized by high absolute prices in the fourth quarter, the average backwardation for the quarter was in line with a normal crude oil market. These market conditions and volatility, in conjunction with our hedging strategies, enhanced the returns of our gathering and marketing activities. This was partially offset by the negative impact that the August 2003 blackout had on our fourth quarter margins. In contrast, market conditions during 2002 were less favorable as the crude oil market alternated between periods of weak contango and strong backwardation. In 2001, the market alternated between weak contango and weak backwardation.

The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	December 31,		
	2003	2002	2001
Operating Results[1] **(in millions)**			
Revenues	$ 11,985.6	$ 7,921.8	$ 6,528.3
Purchases and related costs	11,799.8	7,765.1	6,383.6
Operating expenses (excluding LTIP charge)	73.3	66.3	73.7
LTIP charge—operations	4.3	—	—
Segment margin	108.2	90.4	71.0
General and administrative expenses (excluding LTIP charge)[2]	31.6	31.5	28.5
LTIP charge—general and administrative	13.5	—	—
Segment profit	$ 63.1	$ 58.9	$ 42.5
Noncash SFAS 133 impact[3]	$ 0.4	$ 0.3	$ 0.2
Maintenance capital	$ 1.2	$ 2.6	$ 2.9
Average Daily Volumes (thousands of barrels per day except as otherwise noted)[4][5]			
Crude oil lease gathering	437	410	348
Crude oil bulk purchases	90	68	46
Total	527	478	394
Cushing Terminal throughput	208	110	94
Cushing terminal storage leased to third parties, monthly average volumes	1,165	1,067	2,136

(1) Revenue and purchases include intersegment amounts.

(2) G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment margin and segment profit.

(4) Volumes associated with acquisitions represent weighted averaged daily amounts for the number of days we actually owned the assets over the total days in the period.

(5) Prior period volumes have been adjusted for consistency of comparison between years.

The following factors contributed to our growth in segment margin during 2003 as compared to 2002:

- the overall counter-cyclical balance of our assets and the flexibility embedded in our business strategy;
- increased tankage available to our gathering and marketing business;
- increased lease gathering volumes;

- the backwardated market structure and volatile market conditions;
- increased sales and higher margins in our LPG activities for the first quarter because of cold weather throughout the U.S. and Canada; and
- appreciation of Canadian currency (the Canadian dollar to U.S. dollar exchange rate appreciated to an average of 1.40 to 1 for the year ended December 31, 2003, from an average of 1.57 to 1 for the year ended December 31, 2002).

As discussed above, 2002 market conditions were characterized by periods of weak contango and strong backwardation. Although these conditions are generally disadvantageous for our gathering and marketing activities, the 2001 market conditions were even less favorable. These market conditions and increased crude oil lease gathering volumes contributed to the growth in our segment margin in 2002 as compared to 2001. The increased volumes resulted predominantly from the inclusion of the assets acquired in the CANPET acquisition for the entire year in 2002 as compared to only a portion of 2001. The increase in segment margin was also impacted by decreased operating expenses in the 2002 period as compared to the 2001 period as discussed further below.

The increase in earnings we realized from the factors discussed above was also impacted by the items listed in the table below:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Items Impacting Comparability of Segment Margin			
LTIP accrual	$ (4.3)	$ —	$ —
SFAS 133 impact	0.4	0.3	0.2
Writedown of crude oil operating inventory	—	—	(5.0)
Reserve for doubtful accounts	—	—	(2.0)
Total of items impacting comparability of Segment Margin	$ (3.9)	$ 0.3	$ (6.8)

Operating expenses included in segment margin increased to approximately $77.6 million in the year ended December 31, 2003 compared to $66.3 million and $73.7 million for the years ended December 31, 2002 and 2001, respectively. The increase in 2003 includes the $4.3 million LTIP accrual presented above. The remaining increase was partially related to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher fuel costs. The decrease in operating expenses in 2002 as compared to 2001 was primarily related to the inclusion in 2001 of a $5.0 million noncash writedown of operating crude oil inventory and a $2.0 million noncash reserve for doubtful accounts. The items discussed above were partially offset by the approximately $3.5 million net favorable impact on segment margin from the decrease in the Canadian dollar to U.S. dollar exchange rate in the 2003 period as compared to the 2002 period.

G&A expenses include the costs directly associated with the segments, as well as a portion of corporate overhead costs considered allocable. See "—Other Income and Expenses—Unallocated G&A Expense." G&A expense increased to $45.1 million in 2003 compared to $31.5 million and $28.5 million for 2002 and 2001, respectively. Included in the 2003 amount is $13.5 million related to the accrual for the probable vesting of unit grants under our LTIP. The percentage of indirect costs allocated to the Gathering, Marketing, Terminalling and Storage Operations segment has decreased from period to period as our pipeline operations have grown, partially offsetting the impact of the overall increase in G&A resulting from our continued growth. Segment profit of $63.1 million for 2003 includes $3.9 million related to the items impacting comparability listed above as well as an additional $13.5 million of expense related to the probable vesting of unit grants under our LTIP accrual included in G&A expenses. G&A expenses increased in 2002 from 2001 primarily because of increased costs of $5.6 million from the assets acquired in the CANPET acquisition due to the inclusion of those assets for all of 2002 compared to only a portion of 2001. This increase was offset by decreased G&A of $2.6 million from our domestic operations. This decrease was partially related to a reduction in accounting and consulting costs in 2002 from those that had been incurred in 2001. Partially offsetting these items is the approximately $2.4 million favorable impact on segment profit from the decrease in the Canadian dollar to U.S. dollar exchange rate.

For the year ended December 31, 2003, we gathered from producers, using our assets or third-party assets, approximately 437,000 barrels of crude oil per day, compared to 410,000 barrels per day and 348,000 barrels per day for the years ended December 31, 2002 and 2001, respectively. In addition, we purchased in bulk, primarily at major trading locations, approximately 90,000 barrels of crude oil per day in the 2003 period and approximately 68,000 barrels per day and 46,000 barrels per day in the 2002 and 2001 periods, respectively. Storage leased to third parties at our Cushing facility averaged 1.2 million barrels per month in 2003 compared to an average of 1.1 million barrels per month and 2.1 million barrels per month in 2002 and 2001, respectively. Cushing Terminal throughput volumes averaged approximately 208,000 barrels per day for the year ended December 31, 2003, compared to 110,000 barrels per day and 94,000 barrels per day for the years ended December 31, 2002 and 2001, respectively.

Revenues from our gathering, marketing, terminalling and storage operations were approximately $12.0 billion, $7.9 billion and $6.5 billion for the years ended December 31, 2003, 2002 and 2001, respectively. Revenues and purchases for 2003 were impacted by higher average prices and higher crude oil lease gathering volumes in the 2003 period as compared to the 2002 period. The average NYMEX price for crude oil was $31.08 per barrel and $26.10 per barrel for 2003 and 2002, respectively. Revenues and purchases were predominantly impacted by higher crude oil lease gathering volumes in 2002 as compared to 2001, as the average NYMEX price for crude oil in 2001 was $25.98.

Maintenance capital

For the periods ended December 31, 2003, 2002 and 2001, maintenance capital expenditures were approximately $1.2 million, $2.6 million and $2.9 million, respectively for our gathering, marketing, terminalling and storage operations segment. The decrease in 2003 as compared to 2002 and 2001 is primarily because of a reduction in costs associated with information systems and the replacement of a portion of our fleet.

Other Income and Expenses

Unallocated G&A Expenses

Total G&A expenses were $73.0 million, $45.7 million and $46.6 million for the years ended December 31, 2003, 2002 and 2001, respectively. We have included in the above segment discussion the G&A expenses for each of these years that were attributable to our segments either directly or by allocation. During 2002, we were unsuccessful in our pursuit of several sizable acquisition opportunities determined by auction and one negotiated transaction that had advanced nearly to the execution stage when it was abruptly terminated by the seller. As a result, our 2002 results reflect a $1.0 million charge to G&A expenses associated with the third-party costs of these unsuccessful transactions.

During 2001, we incurred charges of $5.7 million that were not attributable to a segment, related to incentive compensation paid to certain officers and key employees of Plains Resources and its affiliates. In 1998 (in connection with our IPO) and 2000, Plains Resources granted certain officers and key employees of the former general partner the right to earn ownership in a portion of our common units owned by it. These rights provided for vesting over a three-year period, subject to distributions being paid on the common and subordinated units. In connection with the general partner transition in 2001, these rights, as well as grants to directors under our LTIP, vested. This resulted in a charge to our 2001 income of approximately $6.1 million, of which Plains Resources funded approximately 94%. Approximately $5.7 million of the charge was noncash and was not allocated to a segment.

Depreciation and Amortization

Depreciation and amortization expense was $46.8 million for the year ended December 31, 2003, compared to $34.1 million and $24.3 million for the years ended December 31, 2002 and 2001, respectively. The increase in 2003 relates primarily to the inclusion of the assets from the Shell acquisition for the entire year as compared to a portion of 2002. Additionally, several acquisitions were completed during the year along with various capital projects. Amortization of debt issue costs was $3.8 million in 2003, and was essentially unchanged from

$3.7 million in 2002.

The increase in 2002 over 2001 consists of approximately $4.1 million related to the inclusion of assets from the Shell acquisition and approximately $3.5 million related to the inclusion of the assets from the Murphy and CANPET acquisitions for all of 2002 compared to only a portion of 2001. The remainder of the increase is related to increased debt issue costs related to the amendment of our credit facilities during 2002 and late 2001, the sale of senior notes in September 2002 and the completion of various capital projects.

Interest Expense

Interest expense was $35.2 million for the year ended December 31, 2003, compared to $29.1 million for both of the years ended December 31, 2002 and 2001, respectively. The increase in 2003 compared to 2002 was primarily related to an increase in the average debt balance during the 2003 period to approximately $525.5 million from approximately $444.6 million in the 2002 period, which resulted in additional interest expense of approximately $5.0 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. This debt was outstanding for all of 2003 versus only a portion of 2002. Also, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $2.2 million of the increase in the 2003 period. Our weighted average interest rate decreased slightly during 2003 to 6.0% versus 6.2% in 2002, which decreased our interest expense by approximately $1.1 million. Although the change in our weighted average interest rate was nominal, the change was the net result of various factors that included an increase in the amount of fixed rate, long-term debt, long-term interest rate hedges and declining short-term interest rates. In mid-September 2002, we issued $200 million of ten-year bonds bearing a fixed interest rate of 7.75%. In the fourth quarter of 2002 and the first quarter of 2003, we entered into hedging arrangements to lock in interest rates on approximately $50 million of its floating rate debt. In addition, the average three-month LIBOR rate declined from approximately 1.8% during 2002 to approximately 1.2% during 2003. The net impact of these factors, increased commitment fees and changes in average debt balances decreased the average interest rate by 0.2%.

Interest expense was relatively flat in the 2002 period as compared to 2001 due to the impact of higher debt levels and commitment fees offset by lower average interest rates and the capitalization of interest. The overall increased average debt balance in 2002 is due to the portion of the Shell acquisition in August 2002 which was not financed with the issuance of equity. During the third quarter of 2001, we issued a $200 million senior secured term B loan, the proceeds of which were used to reduce borrowings under our revolver. As such, our commitment fees on our revolver increased as they are based on unused availability. The lower interest rates in 2002 are due to a decrease in LIBOR and prime rates in the current year. In addition, approximately $0.8 million of interest expense was capitalized during 2002, in conjunction with expansion construction on our Cushing terminal compared to approximately $0.2 million in the 2001 period.

Other

During the fourth quarter of 2003 we completed the refinancing of our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purchase of hedged crude oil (See "—Liquidity and Capital Resources—Credit Facilities and Long-term Debt"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.

Outlook

Crude Oil and LPG Inventory. We value our crude oil and LPG inventory at the lower of cost or market, with cost determined using an average cost method. At December 31, 2003 we had approximately 3.7 million barrels of inventory classified as unhedged operating inventory at a weighted average cost of $25.41 per barrel. The lower of cost or market method requires a write down of inventory to the market price at the end of a period in which our weighted average cost exceeds the market price. This method does not allow a write up of the inventory if the market price subsequently increases. We did not have an adjustment in this period. However, future fluctuations in crude oil prices could result in a period end lower of cost or market adjustment.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

We are currently involved in advanced discussions with a potential seller regarding the purchase by us of crude oil pipeline, terminalling, storage and gathering and marketing assets for an aggregate purchase price, including assumed liabilities and obligations, ranging from $300 million to $400 million. Such transaction is subject to confirmatory due diligence, negotiation of a mutually acceptable definitive purchase and sale agreement, regulatory approval and approval of both our board of directors and that of the seller.

In connection with our acquisition activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. We had a total of approximately $0.4 million in deferred costs at December 31, 2003. We estimate that our deferred acquisition costs will increase in the first quarter of 2004 by approximately $0.7 million. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

On December 16, 2003, we entered into a definitive agreement to acquire all of Shell Pipeline Company LP's ("SPLC") interests in two entities. The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipe Line System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 667-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois.

During 2003, average daily volumes on SPLC's interest in the Capline system were 125,000 barrels, a decrease from an average of 166,000 barrels per day in 2002 and 213,000 barrels per day in 2001. Effective December 1, 2003, SPLC modified its tariff structure in an effort to increase volume shipments on its space. On a month-to-month basis, average daily volumes on this system are subject to significant volatility. Our acquisition analysis assumed that the average daily volumes on the pipelines would be between 110,000 and 125,000 barrels per day, although it is possible that the volumes will decline below those levels.

The total purchase price for the transaction is approximately $158 million (approximately $142 million, net of the deposit paid). We have sufficient immediate availability under our revolving credit facilities to consummate this transaction. Consistent with our financial growth strategy of funding our acquisition growth with a balance of equity and debt, in December 2003, we issued approximately 2.8 million common units in anticipation of the consummation of this acquisition. See "—Liquidity and Capital Resources—Liquidity."

This acquisition is expected to close during the first quarter of 2004. While we believe it is reasonable to expect the acquisition to close in the first quarter of 2004, we can provide no assurance as to when or whether the acquisition will close.

Basin Expansion. In February 2004, we announced plans to expand a 345-mile section of the system. The section to be expanded extends from Colorado City, Texas to our Cushing Terminal. Upon the completion of this estimated $1.1 million expansion, the capacity of this section will increase approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day.

OCS Production. In October 2003 Plains Exploration and Production announced that they had received all of the necessary permits to develop a portion of the Rocky Point structure that is accessible from the Point Arguello platforms and it appears that they will commence drilling activities in the second quarter of 2004. Such drilling activities, if successful, are not expected to have a significant impact on pipeline shipments on our All American Pipeline system in 2004. If successful, such incremental drilling activity could lead to increased volumes on our All

American Pipeline System in future periods. However, we can give no assurances that our volumes transported would increase as a result of this drilling activity.

Conversion of Subordinated Units and LTIP vesting. In November of 2003, 25% of our outstanding subordinated units converted on a one-for-one basis into common units. During February 2004, the remaining subordinated units converted. As a result, distribution rights are now pari passu among all limited partner units. Further, as a result of these conversions, approximately 326,000 phantom units granted under our LTIP vested in February 2004, and we anticipate that another approximately 473,000 phantom units will vest in May 2004, subject to the satisfaction of service period requirements. We have accrued the majority of the estimated expense associated with the vesting of these units, however, we expect to incur an additional $1.9 million in the first quarter of 2004 and $0.6 million in the second quarter of 2004 primarily related to amortization of service period requirements. We expect to satisfy the May vesting of phantom units by paying cash for the settlement of approximately 201,000 phantom units in lieu of delivering common units and issuing approximately 181,000 common units (after netting for taxes) to satisfy the remainder of the vesting. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

FERC Quarterly Reporting. On February 11, 2004 the FERC issued the final rules on quarterly reporting with, among other things, the addition of the FERC Form No. 6-Q Quarterly Financial Reporting of Oil Pipeline Companies. Our first filing will be due on July 23, 2004. The rules as finalized differ from the original proposal, and we are still analyzing the potential costs associated with compliance. It does not appear at this point that such costs will have a material effect on our financial condition or results of operations, but will add incrementally to our overall regulatory compliance costs.

Sarbanes-Oxley Act and New SEC Rules. Several regulatory and legislative initiatives were introduced in 2002 and 2003 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting disruptions in the capital markets and ensuing calls for action to prevent repetition of those events. Implementation of reforms in connection with these initiatives have added and will add to the costs of doing business for all publicly-traded entities, including the Partnership. These costs will have an adverse impact on future income and cash flow.

Longer Term Outlook. The partnership's longer-term outlook, spanning a period of five or more years, is influenced by many factors affecting the North American crude oil sector. Some of the more significant trends and factors include:

1. Continued overall depletion of U.S. crude oil production.
2. The continuing convergence of worldwide crude oil supply and demand lines.
3. Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels.
4. Industry compliance with the Department of Transportation's adoption of the American Petroleum Institute's standard 653 for testing and maintenance of storage tanks, which will require significant investments to maintain existing crude oil inventory capacity or, alternatively, will result in a reduction of existing inventory capacity by 2009.
5. The introduction of increased crude oil production from North American supplies (primarily Canadian oil sands and deepwater Gulf of Mexico sources) that will, of economic necessity, compete for U.S markets currently being supplied by non-North American foreign crude imports.

We believe the collective impact of these trends, factors and developments, many of which are beyond our control, will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2003, we had a working capital deficit of approximately $68.9 million and approximately $596.8 million of availability under our committed revolving credit facilities and approximately $100 million of availability under the hedged inventory facility. We completed several transactions in the fourth quarter of 2003 that increased our borrowing capacity and enhanced our liquidity position as of December 31, 2003. In November 2003, we refinanced our senior secured credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted, senior secured facility for the purchase of hedged crude oil. We also completed the sale of $250 million of 5.625% senior notes in December of 2003, the proceeds of which were used to pay down outstanding balances on our revolving credit facilities. See "—Credit Facilities and Long-Term Debt." In addition, in anticipation of a potential pending acquisition, during December 2003, we completed a public offering of 2,840,800 common units priced at $31.94 per unit. Net proceeds from the offering, including our general partner's proportionate capital contribution and expenses associated with the offering, were approximately $88.4 million and were used to pay down outstanding balances on our revolving credit facilities.

We believe that we have sufficient liquid assets, cash from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 68.5	$ 173.9	$ (30.0)
Investing activities	(225.3)	(363.8)	(249.5)
Financing activities	157.2	189.5	279.5

Operating Activities. Cash generated by our operations (calculated as net income plus: (i) depreciation and amortization, (ii) the noncash portion of the LTIP charge and (iii) the noncash loss on the refinancing of debt) was approximately $137.6 million for 2003. Approximately $46.8 million of this cash was used for linefill requirements, $6.2 million was used for payments of terminated interest rate swaps and approximately $16.1 million (net) was used for accounts receivable, accounts payable, inventory and other purposes, resulting in approximately $68.5 million of net cash provided by operating activities for 2003.

Approximately $21.1 million of the increase in 2002 as compared to 2001 is due to an increase in net income, predominantly related to our acquisitions completed in April and July 2001 and August 2002. The remainder of the increase is due to changes in working capital items related to the following: (i) the collection of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000; (ii) the collection of prepayments due to the increase in credit risk associated with certain counter-parties; and (iii) the sale of hedged crude oil inventory purchased in 2001 and 2002 and the related changes in accounts receivable and accounts payable. In addition to the hedged inventory transactions having a positive effect on cash provided by operating activities for the year ended December 31, 2002, similar transactions had a negative effect on the year ended December 31, 2001 as the inventory was being purchased and stored, thus resulting in an even larger variance when comparing the two periods.

Investing Activities. Net cash used in investing activities in 2003, 2002 and 2001 consisted predominantly of cash paid for acquisitions. Net cash used in 2003 was $225.3 million and was comprised of (i) an aggregate $152.6 million paid primarily for ten acquisitions completed during 2003, (ii) a $15.8 million deposit paid on the potential pending acquisition from Shell Pipeline Company; see "Acquisitions", (iii) proceeds of approximately $8.5 million from sales of assets, and (iv) $65.4 million paid for additions to property and equipment, including $19.2 million related to the construction of crude oil gathering and transmission lines in West Texas. Net cash used in 2002 was $363.8 million and was comprised of (i) an aggregate $324.6 million paid for three acquisitions completed during 2002; see "Acquisitions", and (ii) $40.6 million paid for additions to property and equipment, primarily related to our Cushing expansion and the construction of the Marshall terminal in Canada. Net cash used in 2001 was $249.5 million and was comprised of (i) an aggregate $229.2 million paid for three acquisitions completed during 2001; see "Acquisitions", and (ii) $21.1 million paid for additions to property and equipment.

Financing Activities. Cash provided by financing activities in 2003 consisted primarily of $499.7 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on our revolving credit facilities and senior term loans. Net repayments of our short-term and long-term revolving credit facilities and related senior term loans were $215.4 million. In addition, $121.8 million of distributions were paid to our unitholders and general partner. Cash provided by financing activities in 2002 consisted of approximately $344.6 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on the revolving credit facility. Net repayments of our short-term and long-term revolving credit facilities during 2002 were $49.9 million. In addition, $99.8 million of distributions were paid to our unitholders and general partner during the year ended December 31, 2002.

Cash provided by financing activities in 2001 consisted primarily of net short-term and long-term borrowings of $134.3 million, proceeds from the issuance of common units of $227.5 million, and the payment of $75.9 million in distributions to our unitholders and general partner.

Universal Shelf

We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $700 million of debt or equity securities. At December 31, 2003, we have approximately $165 million of remaining availability under this registration statement.

Credit Facilities and Long-term Debt

During December 2003, we completed the sale of $250 million of 5.625% senior notes due December 2013. The notes were issued by us and a 100% owned finance subsidiary (neither of which have independent assets or operations) at a discount of $0.7 million, resulting in an effective interest rate of 5.66%. Interest payments are due on June 15 and December 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries that are minor.

During November 2003, we refinanced our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purpose of financing hedged crude oil. The $750 million of new facilities consist of:

- a four-year, $425 million U.S. revolving credit facility;
- a 364-day, $170 million Canadian revolving credit facility with a five-year term-out option;
- a four-year, $30 million Canadian working capital revolving credit facility; and
- a 364-day, $125 million revolving credit facility.

All of the facilities with the exception of the $200 million hedged inventory facility are unsecured. The $200 million hedged inventory facility is an uncommitted working capital facility, which will be used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility will be secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory.

Our credit facilities, the indenture governing the 5.625% senior notes and the indenture governing the 7.75% senior notes contain cross default provisions. 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 if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or 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:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.5 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our 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 facilities and indentures.

The average life of our long-term debt capitalization at December 31, 2003, was approximately 9 years. At the end of the year we had approximately $25.3 million of short-term working capital borrowings outstanding under our $425 million U.S. revolving credit facility, no amounts outstanding under our $125 million, 364-day revolving credit facility, no amounts outstanding under our $30 million Canadian working capital revolving credit facility, approximately $70.0 million outstanding under our $170 million Canadian revolving credit facility that matures in 2009, $200 million of senior notes that mature in 2012 and $250 million of senior notes that mature in 2013.

Contingencies

Industry Credit Markets and Accounts Receivable. Throughout the latter part of 2001 and all of 2002, there were significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and extreme financial distress at several large, diversified energy companies, the energy industry was especially impacted by these developments. We believe that these developments have created an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions relate to our gathering and marketing activities that can generally be described as high volume and low margin activities. In our credit approval process, 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 to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2003, we had received approximately $44.0 million of advance cash payments and prepayments from third parties to mitigate credit risk.

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Department of Commerce. We have determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. On October 2, 2003, we submitted additional information to the BIS. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et. al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled*Alfons Sperber v. Plains Resources Inc., et al.* This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unit holders, asserts breach of fiduciary duty and breach of contract claims against the Partnership, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint seeks to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. The Partnership intends to vigorously defend this lawsuit.

Pipeline and Storage Regulation. Some of our petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation ("DOT") with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. In addition, we must permit access to and copying of records, and must make certain reports available and provide information as required by the Secretary of Transportation. Comparable regulation exists in Canada and in some states in which we conduct intrastate common carrier or private pipeline operations. See Items 1 and 2. "—Business and Properties—Regulation—Pipeline and Storage Regulation."

Regulatory compliance costs include those related to pipeline integrity management (these are recurring expenses estimated to be approximately $1.8 million in 2004) and the adoption by the DOT of API 653 as the standard for the inspection, repair, alteration and reconstruction of jurisdictional storage tanks (these are recurring expenses estimated to be approximately $2 million in 2004). We will continue to refine our estimates as information from initial assessments becomes available. Asset acquisitions are an integral part of our business strategy. As we acquire additional assets we may be required to incur additional costs in order to ensure that the acquired assets comply with pipeline integrity regulations and API 653 standards. The timing of such additional costs is uncertain and could vary materially from our current projections.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope would likely include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. The DOT is in the initial stages of evaluating this initiative and we do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The trend appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities. See Items 1 and 2. "Business and Properties—Operational Hazards and Insurance."

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

Capital Requirements

We have made and will continue to make capital expenditures for acquisitions and expansion and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations, credit facility borrowings, the issuance of senior unsecured notes and the sale of additional common units.

We expect to spend approximately $51.2 million on expansion capital projects during 2004. These projects include $22.5 million on upgrades related to prior acquisitions, $10.0 million on the Cushing Phase IV expansion, $6.0 million on the Iatan System expansion, $4.5 million on information systems related projects and $8.2 million on other operations projects. In addition to these expansion projects, we expect to spend approximately $142.2 million for the pending acquisition of interests in the Capline and Capwood Pipeline systems ($158.0 million including the $15.8 million deposit made in December 2003). In April 2004, we will make the contingent payment related to the CANPET acquisition, as discussed in Note 7—"Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements." We also estimate we will spend approximately $11.7 million in maintenance capital during 2004.

Commitments

Contractual Obligations. In the ordinary course of doing business we enter into various contractual obligations for varying terms and amounts. The following table includes our non-cancellable contractual obligations as of December 31, 2003, and our best estimate of the period in which the obligation will be settled (in millions):

	2004	2005	2006	2007	2008	Thereafter	Total
Long-term debt	$ —	$ —	$ —	$ —	$ —	$ 520.0	$ 520.0
Operating leases[1]	12.7	11.2	8.8	5.3	2.8	0.7	41.5
Capital expenditure obligations[2]	154.7	—	—	—	—	—	154.7
Other long-term liabilities[3][4]	10.9	3.2	1.2	0.6	0.4	0.7	17.0
Total	$ 178.3	$ 14.4	$ 10.0	$ 5.9	$ 3.2	$ 521.4	$ 733.2

(1) Operating leases are primarily for office rent and trucks used in our gathering activities.

(2) Includes approximately $142.2 million for the Capline Acquisition.

(3) Approximately $10.9 million of the balance is related to the portion of our LTIP accrual that we anticipate settling with units in 2004.

(4) Excludes approximately $11.0 million non-current liability related to SFAS 133.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminalling and storage of crude oil and the marketing and storage of LPG. The majority of these contractual commitments are for the purchase of crude oil and LPG that are made under contracts that range in term from a thirty-day evergreen to three years. A substantial portion of the contracts that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. From time to time, we also enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil futures contracts as hedging devices. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The volume and prices of these purchase and sale contracts are subject to market volatility and fluctuate with changes in the NYMEX price of crude oil from period to period. During 2003, these purchases averaged approximately $1.0 billion per month.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2003, we had outstanding letters of credit of approximately $57.9 million.

Distributions. 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 cash and cash equivalents on hand at the end of the quarter less reserves established by our general partner for future requirements. On February 13, 2004, we paid a cash distribution of $0.5625 per unit on all outstanding units. The total distribution paid was approximately $35.2 million, with approximately $28.7 million paid to our common unitholders, $4.2 million paid to our subordinated unitholders and $2.3 million paid to our general partner for its general partner ($0.7 million) and incentive distribution interests ($1.6 million).

Our general partner is entitled to 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, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit. We paid $4.4 million to the general partner in incentive distributions in 2003. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 307 of Regulation S-K.

Risk Factors Related to Our Business

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our segment margin is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.3 million. In addition, any production disruption from these fields due to production problems, transportation problems or other reasons would have a material adverse effect on our business.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

The profitability of our pipeline operations depends on the volume of crude oil shipped by third parties.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, an average 10,000 barrel per day variance in the Basin Pipeline System, equivalent to an approximate 4% volume variance on that pipeline system, would result in an approximate $0.8 million change in annualized segment margin.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast. Any decrease in this demand could adversely affect our business.

Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets, and any decrease in this demand could adversely affect our business. Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand.

We face intense competition in our terminalling and storage activities and gathering and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil. A $0.01 per barrel variance in the aggregate average segment margin would have an approximate $2.0 million annual effect on segment margin.

Newly acquired properties could expose us to environmental liabilities and increased regulatory compliance costs.

Our business plan calls for a continuing acquisition program. Assets that we have acquired or may acquire in the future will likely have associated environmental liabilities, as well as required compliance with regulations such as the integrity maintenance program for regulated pipelines and the API 653 standard for regulated storage. Although we attempt to identify such exposures and address the associated costs through indemnities, purchase price adjustments or insurance, we may experience costs not covered by indemnity, insurance or reserves.

The profitability of our gathering and marketing activities depends primarily on the volumes of crude oil we purchase and gather.

To maintain the volumes of crude oil we purchase, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil. We estimate that a 5,000 barrel per day decrease in barrels gathered by us would have an approximate $1.1 million per year negative impact on segment margin. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities.

There can be no assurance that we have adequately assessed the credit-worthiness of our existing or future counter-parties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

In 1999, we suffered a large loss from unauthorized crude oil trading by a former employee. A loss of this kind could occur again in the future in spite of our best efforts to prevent it.

Generally, it is our policy that as we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. We discovered in November 1999 that this policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

Our operations are subject to federal and state environmental and safety laws and regulations relating to environmental protection and operational safety.

Our pipeline, gathering, storage and terminalling operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. These costs and liabilities could arise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we were not able to recover such resulting costs through insurance or increased tariffs and revenues, our cash flows and results of operations could be materially impacted.

The transportation and storage of crude oil results in a risk that crude oil and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption.

Our Canadian pipeline assets are subject to federal and provincial regulation.

Our Canadian pipeline assets are subject to regulation by the National Energy Board and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

Fluctuations in Demand can Negatively Affect our Operating Results.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we records profits.

The terms of our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders, comply with the terms of our indebtedness or capitalize on business opportunities.

As of December 31, 2003, our total outstanding long-term debt was approximately $519.0 million. Our payment of principal and interest on the debt will reduce the cash available for distribution on the units. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates and foreign currency restrictions and shortages could adversely affect our operating results.

Because we conduct operations outside the U.S., we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations. In addition, legal restrictions or shortages in currencies outside the U.S. may prevent us from converting sufficient local currency to enable us to comply with our currency placement obligations not denominated in local currency or to meet our operating needs and debt service requirements.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our unitholders and our ability to make payments on our debt securities.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

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

Item 7A. *Quantitative and Qualitative Disclosures About Market Risks*

We are exposed to various market risks, including volatility in (i) crude oil and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies and our trading controls and procedures and certain aspects of corporate risk management. To hedge the risks discussed above we engage in price risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 5 to our consolidated financial statements for a discussion of the mitigation of credit risk). Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment margin we receive. Except for the controlled trading program discussed below, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil and an aggregate of 250,000 barrels of LPG.

In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise-level risks and trading-related risks. Enterprise-level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the partial exception of the controlled trading program, our approved strategies are intended to mitigate enterprise-level risks that are inherent in our core businesses of gathering and marketing and storage.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility than in the past. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" in the "Notes to the

Consolidated Financial Statements."

All of our open commodity price risk derivatives at December 31, 2003 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 7.5	$ (6.4)
Swaps and options contracts	$ (3.3)	$ 2.2
LPG:		
Futures contracts	$ —	$ —
Swaps and options contracts	$ (0.7)	$ 0.9

The fair values of the futures contracts are based on quoted market prices obtained from the NYMEX. The fair value of the swaps and option contracts are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions in these estimates as well as the source is maintained by the independent risk control function. All hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2003. The 7.75% senior notes issued during 2002 and the 5.625% senior notes issued during 2003 are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2003. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates.

	Expected Year of Maturity						
	2004	2005	2006	2007	2008	Thereafter	Total
	(in millions)						
Liabilities:							
Short-term debt—variable rate	$ 125.8	$ —	$ —	$ —	$ —	$ —	$ 125.8
Average interest rate	2.3%	—	—	—	—	—	2.3%
Long-term debt—variable rate	$ —	$ —	$ —	$ —	$ —	$ 70.0	$ 70.0
Average interest rate	—	—	—	—	—	2.2%	2.2%

Interest rate swaps are used to hedge underlying interest payment obligations. We estimate the fair value of these instruments based on current termination values. 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.

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

	Year of Maturity				
	2004	2005	2006	2007	Total
Interest rate swaps	$ (0.4)	$ —	$ —	$ —	$ (0.4)

At December 31, 2003, an interest rate swap with an aggregate notional principal amount of $50 million was outstanding. The interest rate swap is based on LIBOR rates and provides for a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin.

Currency Exchange Risk

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, expenses and cash flow are translated using the average exchange rate during the reporting period.

Because a significant portion of our Canadian business is conducted in Canadian dollars, 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 times, a portion of our debt is denominated in Canadian dollars. At December 31, 2003, we did not have any Canadian dollar debt. All of the financial instruments utilized are placed with large creditworthy financial institutions.

At December 31, 2003, we had forward exchange contracts that allow us to exchange $2.0 million Canadian for at least $1.5 million U.S. quarterly during 2004 (based on a Canadian dollar to U.S. dollar exchange rate of 1.33 to 1) and $1.0 million Canadian for at least $0.7 million U.S. quarterly during 2005 (based on a Canadian dollar to U.S. dollar exchange rate of 1.34 to 1). At December 31, 2003, we also had cross currency swap contracts for an aggregate notional principal amount of $23.0 million effectively converting this amount of our U.S. dollar denominated debt to $35.6 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2004 and May 2005 and has a final maturity in May 2006 ($19.0 million U.S.).

We estimate the fair value of these instruments based on current termination values. The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in millions):

	Year of Maturity				
	2004	2005	2006	2007	Total
Forward exchange contracts	$ (0.3)	$ (0.1)	$ —	$ —	$ (0.4)
Cross currency swaps	(1.0)	(0.7)	(3.1)	—	(4.8)
Total	$ (1.3)	$ (0.8)	$ (3.1)	$ —	$ (5.2)

Item 8. ***Financial Statements and Supplementary Data***

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

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure. Our DCP is incremental to our system of internal accounting controls designed to comply with the requirements of Section 13(b)(2) of the Exchange Act.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP, as of December 31, 2003, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Management (including our Chief Executive Officer and Chief Financial Officer) has evaluated the effectiveness of the design and operation of our DCP as of December 31, 2003, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the fourth quarter of 2003 and that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350 are furnished with this report as exhibits 32.1 and 32.2.