

PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 26, 2009

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**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

Form 10-K

(Mark
One)

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

or

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

76-0582150
(I.R.S. Employer
Identification No.)

333 Clay Street, Suite 1600, Houston, Texas
(Address of principal executive offices)

77002
(Zip Code)

(713) 646-4100

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer Accelerated Filer Non-Accelerated Filer Smaller Reporting Company
(Do not check if a smaller reporting company)

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately \$4.9 billion on June 30, 2008, based on \$45.11 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2009, there were outstanding 122,911,645 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE **NONE**

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**PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K 2008 ANNUAL REPORT**

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FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," as well as similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

failure to implement or capitalize on planned internal growth projects;

maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

the success of our risk management activities;

environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

shortages or cost increases of power supplies, materials or labor;

the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

the availability of, and our ability to consummate, acquisition or combination opportunities;

our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

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unanticipated changes in crude oil market structure and volatility (or lack thereof);

the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

the effects of competition;

interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

increased costs or lack of availability of insurance;

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fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

the currency exchange rate of the Canadian dollar;

weather interference with business operations or project construction;

risks related to the development and operation of natural gas storage facilities;

future developments and circumstances at the time distributions are declared;

general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and pervasive liquidity concerns; and

other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read "Risks Related to Our Business" discussed in Item 1A. "Risk Factors." Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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PART I

Items 1 and 2. Business and Properties

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms "Partnership," "Plains," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as "LPG." Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC ("PAA/Vulcan"), we are also involved in the development and operation of natural gas storage facilities.

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage and marketing services to our producer, refiner and other customers. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil, refined products and LPG in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling and storage assets with our extensive marketing and distribution expertise.

We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to manage and grow our business by:

optimizing our existing assets and realizing cost efficiencies through operational improvements;

developing and implementing internal growth projects that (i) address evolving crude oil, refined products and LPG needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;

utilizing our assets along the Gulf, West and East Coasts along with our Cushing Terminal and leased assets to optimize our presence in the waterborne importation of foreign crude oil;

expanding our presence in the refined products supply and marketing sector;

selectively pursuing strategic and accretive acquisitions of crude oil, refined products and LPG transportation, terminalling, storage and marketing assets and businesses that complement our existing asset base and distribution capabilities; and

using our terminalling and storage assets in conjunction with our marketing activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin.

PAA/Vulcan's natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. PAA/Vulcan's natural gas storage growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive natural gas storage projects and facilities. We may also prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities.

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Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. We intend to maintain a credit profile that we believe is consistent with an investment grade credit rating. We have targeted a general credit profile with the following attributes:

an average long-term debt-to-total capitalization ratio of approximately 50%;

an average long-term debt-to-adjusted EBITDA multiple of approximately 3.5x (adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring); and

an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

The first two of these three metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with marketing activities that involve the simultaneous purchase and forward sale of crude oil, refined products and LPG. The crude oil, refined products and LPG purchased in these transactions are hedged. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt for New York Mercantile Exchange ("NYMEX") and IntercontinentalExchange ("ICE") margin requirements. NYMEX is part of CME Group Inc. and is referred to as NYMEX throughout this document.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from capital expansion projects to adjusted EBITDA. At December 31, 2008 and for the year then ended, we were in line with our targeted metrics.

Credit Rating

As of February 2009, our senior unsecured ratings with Standard & Poor's and Moody's Investment Services were BBB-, stable outlook, and Baa3, stable outlook, respectively, both of which are considered "investment grade" ratings. We have targeted the attainment of stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor's and Moody's Investment Services, respectively. However, our current ratings might not remain in effect for any given period of time, we might not be able to attain the higher ratings we have targeted and one or both of these ratings might be lowered or withdrawn entirely by the rating agencies. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time. See Item 1A. "Risk Factors Risks Related to Our Business Loss of credit rating or the ability to receive open credit could negatively affect our ability to use the counter-cyclical aspects of our asset base or to capitalize on a "volatile market" for discussion of the potential impacts of a downgrade in our credit ratings.

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Competitive Strengths

We believe that the following competitive strengths position us to successfully execute our principal business strategy:

Many of our transportation segment and facilities segment assets are strategically located and operationally flexible. The majority of our primary transportation segment assets are in crude oil service, are located in well-established oil producing regions and transportation corridors, and are connected, directly or indirectly, with our facilities segment assets located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where we have strong business relationships.

We possess specialized crude oil market knowledge. We believe our business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise, provide us with an extensive understanding of the North American physical crude oil markets.

Our crude oil marketing activities are counter-cyclically balanced. We believe the variety of activities provided by our marketing segment provides us with a counter-cyclical balance that generally affords us the flexibility (i) to maintain a base level of margin irrespective of crude oil market conditions and (ii), in certain circumstances, to realize incremental margin during volatile market conditions.

We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities. Over the past eleven years, we have completed and integrated approximately 52 acquisitions with an aggregate purchase price of approximately \$6.0 billion. We have also implemented internal expansion capital projects totaling approximately \$1.8 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2008, we had approximately \$1.0 billion available under our committed credit facilities, subject to continued covenant compliance.

We have an experienced management team whose interests are aligned with those of our unitholders. Our executive management team has an average of approximately 25 years industry experience, and an average of approximately 15 years with us or our predecessors and affiliates. In addition, through their ownership of common units, indirect interests in our general partner, grants of phantom units and the Class B units in Plains AAP, L.P., our management team has a vested interest in our continued success.

We believe these competitive strengths will aid our efforts to expand our presence in the refined products, LPG and natural gas storage sectors.

Organizational History

We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. References to our "general partner," as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are owned by 17 holders, with six of these holders each owning a minimum interest of approximately 3% and an aggregate interest of 93%. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest."

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Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. Plains All American GP LLC has ultimate responsibility for conducting our business and managing our operations. See Item 10. "Directors and Executive Officers of our General Partner and Corporate Governance." Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for substantially all direct and indirect expenses incurred on our behalf (other than expenses related to the Class B units of Plains AAP, L.P.).

The chart below depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries.

-
- (1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 25 million limited partner units, representing approximately 20% of all outstanding units.
- (2) Incentive Distribution Rights ("IDRs"). See Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities" for discussion of our general partner's incentive distribution rights.

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- (3) The Partnership holds 100% direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Pipeline, L.P., Plains Marketing, L.P., Plains LPG Services, L.P., Pacific Energy Group LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P and Plains Midstream Canada ULC.
- (4) The Partnership holds direct and indirect equity interests in unconsolidated entities including PAA/Vulcan, Settoon Towing, LLC ("Settoon Towing"), Butte Pipe Line Company ("Butte") and Frontier Pipeline Company ("Frontier").

Acquisitions

The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets, LPG assets and natural gas storage assets, as well as other energy transportation related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. We have established a target to complete, on average, \$200 million to \$300 million in acquisitions per year, subject to availability of attractive assets on acceptable terms. Between 1998 and December 31, 2008, we have completed approximately 52 acquisitions for a cumulative purchase price of approximately \$6.0 billion.

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The following table summarizes acquisitions greater than \$50 million that we have completed over the past five years (in millions):

Acquisition	Date	Description	Approximate Purchase Price
Rainbow Pipe Line Company	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	\$ 687
Tirzah Storage Facility	Oct-2007	Liquefied Petroleum Gas storage facility	\$ 54
Bumstead Storage Facility	Jul-2007	Liquefied Petroleum Gas storage facility	\$ 52
Pacific Energy Partners LP ("Pacific")	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	\$ 2,456
El Paso to Albuquerque Products Pipeline Systems	Sep-2006	Three refined products pipeline systems	\$ 66
CAM/BOA/HIPS Crude oil systems	Jul-2006	59.89% interest in the Clovelly-to-Meraux ("CAM") Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-to-Alliance ("BOA") system and various interests in the High Island Pipeline System ("HIPS") ⁽¹⁾	\$ 130
Andrews Petroleum and Lone Star Trucking ("Andrews")	Apr-2006	Isomerization, fractionation, marketing and transportation services	\$ 220
South Louisiana Gathering and Transportation Assets ("SemCrude")	Apr-2006	Crude oil gathering and transportation assets, including inventory and related contracts in South Louisiana	\$ 129
Investment in Natural Gas Storage Facilities	Sep-2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities	\$ 125 ⁽²⁾
Link Energy LLC	Apr-2004	North American crude oil and pipeline operations of Link Energy, LLC ("Link")	\$ 332
Capline and Capwood Pipeline Systems	Mar-2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximately 76% undivided joint interest in the Capwood Pipeline System	\$ 159

(1) Our interest in HIPS was relinquished in November 2006.

(2) Represents 50% of the purchase price for the acquisition made by our joint venture. The joint venture completed an acquisition for approximately \$250 million during 2005.

2008 Acquisitions

During 2008, we completed two acquisitions for aggregate consideration of approximately \$735 million. These acquisitions included (i) a crude oil pipeline located in Alberta, Canada (reflected in our transportation segment) for approximately \$687 million in cash of which the associated goodwill was approximately \$194 million and (ii) a storage facility and other assets (reflected in our facilities segment) for approximately \$44 million in cash of which there was no associated goodwill.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil, refined products and LPG related

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assets and, through our interest in PAA/Vulcan, natural gas storage assets. In addition, we have in the past evaluated and pursued, and intend in the future to evaluate and pursue, other energy related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. "Risk Factors Risks Related to Our Business If we do not make acquisitions on economically acceptable terms, our future growth may be limited" and " Our acquisition strategy involves risks that may adversely affect our business."

Global Petroleum Market Overview

The United States comprises less than 5% of the world's population and generates only 10% of the world's petroleum production, but consumes 23% of the world's petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil, natural gas liquids and other liquid petroleum products) and is derived from the Energy

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Information Administration's ("EIA") Annual Energy Outlook 2009 Early Release (see EIA website at www.eia.doe.gov).

	Projected			
	2008 ⁽¹⁾	2009	2010	2015
(In millions of barrels per day)				
Supply				
U.S.	8.5	9.1	9.7	10.2
Other OECD	12.4	12.0	12.0	11.5
Total OECD ⁽²⁾	20.9	21.1	21.7	21.7
Organization of the Petroleum Exporting Countries	35.8	35.1	34.5	35.9
Other Non-OECD	28.8	30.1	30.6	31.9
Total World Production	85.5	86.3	86.8	89.5
	Projected			
	2008 ⁽¹⁾	2009	2010	2015
(In millions of barrels per day)				
Demand				
U.S.	19.7	19.2	19.8	20.2
Other OECD	28.0	28.0	27.5	27.0
Total OECD	47.7	47.2	47.3	47.2
Non-OECD	38.2	39.1	39.5	42.3
Total World Consumption	85.9	86.3	86.8	89.5
Net World Consumption	(0.4)			
U.S. Production as % of World Production	10%	11%	11%	11%
U.S. Consumption as % of World Consumption	23%	22%	23%	23%
Net U.S. Consumption	(11.2)	(10.1)	(10.1)	(10.0)

(1) The 2008 amounts are based on ten months of actual data and two months of data derived from a short-term energy model published by the EIA.

(2) Organization for Economic Co-operation and Development

World economic growth is a driver of the world petroleum market. To the extent that an event causes weaker world economic growth, energy demand would decline. Weaker energy demand would also result in lower energy consumption, lower energy prices, or both, depending on the production responses of producers. Recent volatility in the financial markets and other geopolitical factors have contributed to uncertainty in the petroleum market and, therefore, have caused significantly higher volatility in prices and market structure. In addition, the challenging global economic climate has recently resulted in lower prices as well as reduced demand.

Crude Oil Market Overview

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The definition of a commodity is a "mass-produced unspecialized product" and implies the attribute of fungibility. Crude oil is typically referred to as a commodity, however it is neither unspecialized nor fungible. The crude slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. Each crude grade has distinguishing physical properties, such as specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, which result in varying economic attributes.

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In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value.

The lack of fungibility of the various grades of crude oil creates logistical transportation, terminalling and storage challenges and inefficiencies associated with regional volumetric supply and demand imbalances. These logistical inefficiencies are created as certain qualities of crude oil are indigenous to particular regions or countries. Also, each refinery has a distinct configuration of process units designed to handle particular grades of crude oil. The relative yields and the cost to obtain, transport and process the crude oil drives the refinery's choice of feedstock. In addition, from time to time, natural disasters and geopolitical factors such as hurricanes, earthquakes, tsunamis, inclement weather, labor strikes, refinery disruptions, embargoes and armed conflicts may impact supply, demand and transportation and storage logistics.

Our assets and our business strategy are designed to serve our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. According to the EIA, during the twelve months ended October 2008, the United States consumed approximately 14.8 million barrels of crude oil per day, while only producing 5.0 million barrels per day. Accordingly, the United States relies on foreign imports for approximately 66% of the crude oil used by U.S. domestic refineries. This imbalance represents a continuing trend. Foreign imports of crude oil into the U.S. have tripled over the last 23 years, increasing from 3.2 million barrels per day in 1985 to 9.8 million barrels per day for the 12 months ended October 2008, as U.S. refinery demand has increased from 12.0 million barrels per day in 1985 to 14.8 million barrels per day for the twelve months ended October 2008 and domestic crude oil production has declined due to natural depletion. The table below shows the overall domestic petroleum consumption projected out to 2015 and is derived from recent information published by the EIA (see EIA website at www.eia.doe.gov). The amounts in the 2008 column are based on the twelve months from November 2007 to October 2008.

		Projected			
		2008	2009	2010	2015
		(In millions of barrels per day)			
Supply					
Domestic Crude Oil Production		5.0	5.4	5.6	5.7
Net Imports Crude Oil		9.8	9.0	8.3	8.2
Crude Oil Input to Domestic Refineries		14.8	14.4	13.9	13.9
Net Product Imports		1.3	1.3	1.6	1.7
Other (NGL Production, Refinery Processing Gain)		3.6	3.5	4.3	4.6
Total Domestic Petroleum Consumption		19.7	19.2	19.8	20.2

The Department of Energy segregates the United States into five Petroleum Administration Defense Districts ("PADDs"), which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for

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each PADD for the twelve months ended October 2008 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov) (in millions of barrels per day).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
PADD I (East Coast)		1.5	(1.5)
PADD II (Midwest)	0.5	3.2	(2.7)
PADD III (South)	2.7	7.0	(4.3)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.4	2.6	(1.2)
Total U.S.	5.0	14.8	(9.8)

Although PADD III has the largest absolute volume supply shortfall, we believe PADD II is the most critical region with respect to supply and transportation logistics because it is the largest, most highly populated area of the U.S. that does not have direct access to oceanborne cargoes.

Over the last 23 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 515,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.2 million barrels per day for the twelve months ended October 2008. As a result, the volume of crude oil transported into PADD II has increased approximately 59% in absolute terms or 2.0% annually from 1.7 million barrels per day to 2.7 million barrels per day. This aggregate shortfall is principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

Volatility in the crude oil market has increased and we expect it to persist. Some factors that we believe are causing and will continue to cause volatility in the market include:

The multi-year trend narrowing the gap between supply and demand;

Temporal increases in the gap related to supply response following price spikes and declines in the rate of demand growth due to worldwide economic slowdown;

A reduction in available tankage and U.S. inventory capacity caused by U.S. Department of Transportation ("DOT") regulations requiring regularly scheduled inspection and repair of tanks remaining in service;

Regional supply and demand imbalances;

Political instability in critical producing nations; and

Significant fluctuations in absolute price as well as grade and location differentials.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business. We believe we are well positioned to capture such opportunities through our:

strategically located assets;

specialized crude oil market knowledge;

extensive relationships with producers and refiners;

strong capital structure and liquidity position; and

proven skill sets to acquire and integrate businesses and achieve synergies.

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Refined Products Market Overview

Once crude oil is transported to a refinery, it is processed into different petroleum products. These "refined products" fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel and jet fuel); finished non-fuel products such as solvents, lubricating oils and asphalt; and feedstocks for the petrochemical industry such as naphtha and various refinery gases. Demand is greatest for products in the fuels category, particularly motor gasoline.

The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced and the type of crude oil that is used. Gasoline characteristics are also impacted by other ingredients that may be blended into it, such as ethanol and octane enhancers. The performance of the gasoline must meet strictly defined industry standards and environmental regulations that vary based on season and location.

After crude oil is refined into gasoline and other petroleum products, the products are distributed to consumers. The majority of products are shipped by pipeline to storage terminals near consuming areas, and then loaded into trucks for delivery to gasoline stations and end users. Products that are used as feedstocks are typically transported by pipeline or barges to chemical plants.

Demand for refined products has generally been affected by price levels, economic growth trends and, to a lesser extent, weather conditions. According to the EIA, consumption of refined products in the United States has risen from approximately 15.7 million barrels per day in 1985 to approximately 19.7 million barrels per day for the twelve months ended October 2008, an annual average increase of approximately 1.0%. Due to current challenging economic conditions, the EIA estimates that U.S. consumption of refined products will decline in 2009 before increasing again. We believe that the additional demand in the intermediate and long-term will be met by growth in the capacity of existing refineries through large expansion projects and "capacity creep" as well as increased imports of refined products, both of which we believe will generate incremental demand for midstream infrastructure, such as pipelines and terminals.

We believe that demand for refined products pipeline and terminalling infrastructure will also increase as a result of:

multiple specifications of existing products (also referred to as boutique gasoline blends);

specification changes to existing products, such as ultra low sulfur diesel;

new products, such as bio-fuels;

the aging of existing infrastructure; and

the potential reduction in storage capacity due to regulations governing the inspection, repair, alteration and construction of storage tanks.

The complexity and volatility of the refined products market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities through our:

strategically located assets;

specialized refined products knowledge;

extensive relationships with refiners, other suppliers, distributors and end-users;

strong capital structure and liquidity position; and

proven skill sets to evaluate, acquire and integrate businesses and achieve synergies.

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We intend to grow our asset base in the refined products business through expansion projects and future acquisitions. Consistent with our plan to apply our proven business model to these assets, we also intend to optimize the value of our refined products assets and better serve the needs of our customers by continuing to build a complementary refined products supply and marketing business.

LPG Products Market Overview

LPGs are a group of hydrogen-based gases that are derived from crude oil refining and natural gas processing. They include propane, butane, isobutane and other related products. These gases liquefy at moderate pressures thus allowing transportation and storage opportunities. LPG is produced domestically or imported into the U.S. from Canada and other parts of the world. Individual LPG products have specific uses. For example, propane can be used in domestic applications (home heating and cooking), industrial applications, agricultural applications (crop drying) and as an automotive fuel. Normal butane is used as a petrochemical feedstock, as a blendstock for motor gasoline, and to derive isobutane through isomerization. Isobutane is principally used in refinery alkylation to enhance the octane content of motor gasoline or in the production of isooctane or other octane additives. Certain LPGs are also used as diluent in the transportation of heavy oil, particularly in Canada.

The LPG market is driven by:

seasonal shifts in weather;

seasonal changes in gasoline specifications affecting demand for butane;

alternating needs of refineries to store and blend LPG;

complex transportation logistics;

shortages of diluent for Canadian heavy oil; and

inefficiencies caused by regional supply and demand imbalances.

The complexity and volatility of the LPG market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities. We intend to grow our asset base in the LPG business through expansion projects and future acquisitions. We believe that our asset base provides flexibility in meeting the needs of our customers and opportunities to capitalize on regional supply and demand imbalances in LPG markets.

Natural Gas Storage Market Overview

After treatment for impurities such as carbon dioxide and hydrogen sulfide and processing to separate heavier hydrocarbons from the gas stream, natural gas from one source generally is fungible with natural gas from any other source. Because of its fungibility and physical volatility and the fact that it is transported in a gaseous state, natural gas presents different logistical transportation challenges than crude oil and refined products. From 1990 to 2007, domestic natural gas production grew approximately 0.4% annually while domestic natural gas consumption rose approximately 1.0% annually, resulting in an approximate 3.1% annual increase in the domestic supply shortfall over that time period. In addition, significant excess domestic production capacity contractually withheld from the market by take-or-pay contracts between natural gas producers and purchasers in the late 1980s and early 1990s has since been eliminated. However, this trend of an increasing domestic supply shortfall is not expected to continue. During 2008, domestic production increased approximately 6% over production levels in 2007, with the majority of the increases being associated with onshore development of various resource plays, including shale gas. Through 2008, consumption of natural gas was approximately the same as consumption in 2007 on an average daily basis.

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The downturn in the economy clearly has had a negative impact on industrial demand. A portion of this demand destruction has been offset by a significant decrease in commodity price coupled with continued growth for natural-gas fired electric generation. An unprecedented amount of new infrastructure in the form of large diameter pipelines bringing unconventional supply (shale gas) to markets to meet this forecasted demand will have a significant impact on changing traditional physical flows of natural gas particularly in the Gulf Coast area. Even with the growth of unconventional shale plays, North American LNG imports are forecasted to play a potentially significant role. LNG imports totaled approximately 2.1 Bcf per day in 2007 and 1.0 Bcf per day in 2008, but are projected to increase to 4.2 Bcf per day in 2014 with the majority of this supply expected to be delivered to the U.S. markets in the spring and summer.

We believe new pipeline infrastructure, increased domestic supply and increased seasonal deliveries of LNG combined with fluctuations in domestic consumption related to seasonal and economic factors will continue to drive demand for strategically located natural gas storage facilities with multi-cycle injection and withdrawal capabilities. We believe our natural gas storage locations, which have access to critical transportation infrastructure, will continue to play an increasingly important role in balancing the markets and ensuring reliable delivery of natural gas to the customer during peak demand periods. We believe that our expertise in hydrocarbon storage, strategically located assets, financial strength and commercial experience will enable us to play a meaningful role in meeting the challenges and capitalizing on the opportunities associated with the evolution of the U.S. natural gas storage markets.

Description of Segments and Associated Assets

Our business activities are conducted through three segments Transportation, Facilities and Marketing. We have an extensive network of transportation, terminalling and storage facilities at major market hubs and in key oil producing basins and crude oil, refined product and LPG transportation corridors in the United States and Canada.

Following is a description of the activities and assets for each of our business segments.

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Butte, Frontier and Settoon Towing, in which we own non-controlling interests.

As of December 31, 2008, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

17,000 miles of active crude oil and refined products pipelines and gathering systems;

24 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;

1 million barrels of crude oil linefill in pipelines owned by us;

86 trucks and 341 trailers; and

65 transport and storage barges and 36 transport tugs through our interest in Settoon Towing.

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Following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2008, grouped by geographic location:

Region / Pipeline and Gathering Systems ⁽¹⁾	System Miles	2008 Average Net Barrels per Day (in thousands) ⁽²⁾
<u>Southwest US</u>		
Basin	521	377
Other	4,135	467
Southwest US Subtotal	4,656	844
<u>Western US</u>		
All American	138	45
Line 63/Line 2000	459	147
Other	155	103
Western US Subtotal	752	295
<u>US Rocky Mountain</u>		
Salt Lake City Area Systems	1,011	93
Other	3,289	266
US Rocky Mountain Subtotal	4,300	359
<u>US Gulf Coast</u>		
Capline ⁽³⁾	633	219
Other	1,035	311
US Gulf Coast Subtotal	1,668	530
<u>Central US Subtotal</u>		
	2,921	392
Domestic Total	14,297	2,420
<u>Canada</u>		
Rangeland	900	58
Rainbow ⁽⁴⁾	599	193
Manito	605	70
Other	635	175
Canada Total	2,739	496
Grand Total	17,036	2,916

(1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%.

(2) Represents average volumes for the entire year, except for Rainbow, which was acquired during May 2008.

(3) Non-operated pipeline.

(4) Rainbow 2008 average net barrels per day was calculated based on a 245-day period, which was the number of days we owned the asset in 2008.

Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil

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from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 521-mile mainline, telescoping crude oil system with a capacity ranging from approximately 144,000 barrels per day to 400,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 377,000 barrels per day (attributable to our interest) during 2008.

The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 7 million barrels (6 million barrels, net to our interest) of crude oil storage capacity located along the system. The Basin system is subject to tariff rates regulated by the FERC.

Western US

All American Pipeline System. We own a 100% interest in the All American Pipeline system. The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 128 miles to our station in Emidio, California (30-inch diameter pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley Gathering System, Line 2000 and Line 63, as well as other third party intrastate pipelines. The system is subject to tariff rates regulated by the FERC.

The All American Pipeline currently transports OCS crude oil received at the onshore facilities of the Santa Ynez field at Las Flores and the onshore facilities of the Point Arguello field located at Gaviota. ExxonMobil, which owns all of the Santa Ynez production, and Plains Exploration and Production Company and other producers that together own approximately 70% of the Point Arguello production, have entered into transportation agreements committing to transport all of their production from these fields on the All American Pipeline. These agreements provide for a minimum tariff with annual escalations based on specific composite indices. The producers from the Point Arguello field that do not have contracts with us have no other existing means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the filed (or contracted) tariffs. For 2008, 2007 and 2006, tariffs on the All American Pipeline averaged \$2.24 per barrel, \$2.18 per barrel and \$2.07 per barrel, respectively. The agreements do not require these owners to transport a minimum volume. These agreements include an annual one year evergreen provision that requires one year's advance notice to cancel.

With the acquisition of Line 63 and Line 2000, a significant portion of our transportation segment profit is derived from the pipeline transportation business associated with the Santa Ynez and Point Arguello fields and fields located in the San Joaquin Valley. Volumes shipped from the OCS are in decline (as reflected in the table below). See Item 1A. "Risk Factors" for discussion of the estimated impact of a decline in volumes.

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The table below sets forth the historical volumes received from both of these fields for the past five years (barrels in thousands):

	For the Year Ended December 31,				
	2008	2007	2006	2005	2004
Average daily volumes received from:					
Point Arguello (at Gaviota)	7	8	9	10	10
Santa Ynez (at Las Flores)	38	38	40	41	44
 Total	 45	 46	 49	 51	 54

Line 63. We own a 100% interest in the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 115-mile trunk pipeline (of which 101 miles is 14-inch pipe and 14 miles is 16-inch pipe), originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes 26 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 188 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 25 storage tanks with approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2008, combined throughput on Line 63 totaled an average of approximately 89,000 barrels per day.

Line 2000. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (that is part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, 20-inch trunk pipeline with a throughput capacity of 130,000 barrels per day. During 2008, throughput on Line 2000 averaged approximately 58,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We own and operate 100% of the Salt Lake City Core Area systems, which include an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the U.S. Rocky Mountain region to refiners in Salt Lake City, Utah. The Salt Lake City Core Area systems consist of 1,011 miles of pipelines (including the Wahsatch Expansion discussed below) and 26 storage tanks with a total storage capacity of approximately 1 million barrels. The trunk pipeline originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming and various other points between Guernsey and Salt Lake City, and can deliver to Salt Lake City, Utah and Rangely, Colorado. The Salt Lake City Core Area systems have a combined throughput capacity of approximately 120,000 barrels per day to Salt Lake City. During 2008, throughput on the Salt Lake City Core Area systems averaged approximately 93,000 barrels per day.

In the fourth quarter of 2008, we completed construction on a 93-mile expansion of the Salt Lake City Core Area system from Wahsatch, Utah to Salt Lake City, which has throughput capacity of 120,000 barrels per day. We have entered into 10-year transportation contracts with four Salt Lake City refiners for service on this pipeline. Also, in November 2007, we signed a master formation agreement through which we will sell a 25% interest in this line to Holly Energy Partners-Operating, L.P. As part of this agreement, Holly Refining and Marketing Company has entered into a 10-year transportation agreement on terms consistent with the four previously committed refiners. Plains' portion of the total

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project cost was approximately \$215 million. We expect to place the line in service and close on this agreement in the first quarter of 2009.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system, in which we own a 22% undivided joint interest, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing approximately 3 million barrels of refining capacity in PADD II. Shell is the operator of this system. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to the Louisiana Offshore Oil Port, it is a key transporter of sweet and light sour foreign crude to PADD II. Total system operating capacity is approximately 1 million barrels per day of crude oil, of which approximately 248,000 barrels per day is attributable to our interest. During 2008, throughput on our interest averaged approximately 219,000 barrels per day.

Canada

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system is 599 miles long consisting of a 480-mile, 20-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 119 miles of gathering pipelines. The system has a throughput capacity of approximately 200,000 barrels per day and has transported approximately 193,000 barrels per day since we acquired it in May 2008.

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system includes the Mid Alberta Pipeline ("MAPL") and the Rangeland Pipeline. MAPL is a 139-mile proprietary pipeline with a throughput capacity of approximately 50,000 barrels per day if transporting light crude oil. Currently, MAPL originates in Edmonton, Alberta and terminates in Sundre, Alberta, where it connects to the Rangeland Pipeline. We plan to reverse MAPL allowing for flow from Rangeland's Sundre terminal directly to Edmonton. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 761 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections (or on our system once MAPL is reversed) or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S./Canadian border consists of approximately 264 miles of trunk pipelines and has a current throughput capacity of approximately 83,000 barrels per day if transporting light crude oil. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines: a 56-mile pipeline for low sulfur crude oil, a 56-mile pipeline for high sulfur crude oil, and a 50-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For 2008, approximately 34,000 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and approximately 24,000 barrels per day was transported on the pipeline from Sundre south to the United States. There is approximately 80,000 barrels of tankage at the pipeline terminals at Edmonton. An additional 240,000 barrels of tankage is under construction at Edmonton and is expected to be completed in 2009.

Manito. We own a 100% interest in the Manito heavy oil system. This 605-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. Dulwich is the initiation point of the Manito pipeline which is 376 miles long and terminates in Kerrobert, Saskatchewan at our storage and terminalling facility. The Bodo/Cactus Lake pipeline is 145 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge

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pipeline system. For 2008, approximately 70,000 barrels per day of crude oil was transported in the Manito system.

Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease tank capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier and (iii) fees from LPG fractionation and isomerization services.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2008, PAA/Vulcan owned and operated approximately 31 billion cubic feet of underground natural gas storage capacity, which includes 5 billion cubic feet that was placed in service during October 2008, and another 2 Bcf of storage capacity leased from third parties. We are developing an additional 19 billion cubic feet of underground storage capacity, which is expected to be placed into service in phases over the next several years.

As of December 31, 2008, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

approximately 55 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;

approximately 6 million barrels of LPG storage capacity; and

a fractionation plant in Canada with a processing capacity of 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of 22,500 barrels per day.

At year-end 2008, we were in the process of constructing approximately 5 million barrels of additional above-ground crude oil and refined product terminalling and storage facilities.

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Following is a tabular presentation of our active facilities segment assets in the United States and Canada as of December 31, 2008, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
<i>Cushing</i>	11
<i>Kerrobert</i>	1
<i>L.A. Basin</i>	10
<i>Martinez and Richmond</i>	5
<i>Mobile and Ten Mile</i>	2
<i>Patoka</i>	3
<i>Philadelphia Area</i>	3
<i>St. James</i>	6
<i>Other</i>	14
Subtotal	55
LPG	
<i>Bumstead</i>	2
<i>Tirzah</i>	1
<i>Other</i>	3
Subtotal	6
Natural Gas	
<i>Bluewater/Kimball⁽¹⁾</i>	26 Bcf ⁽²⁾⁽³⁾
<i>Pine Prairie⁽¹⁾</i>	5 Bcf ⁽²⁾⁽³⁾

(1) Owned through our interest in PAA/Vulcan.

(2) Our interest in these facilities is 50% of the capacity.

(3) Billion cubic feet ("Bcf")

Below is a detailed description of our more significant facilities segment assets.

Major Facilities Assets

Crude Oil and Refined Products

Cushing Terminal. Our Cushing, Oklahoma Terminal (the "Cushing Terminal") is located at the Cushing Interchange, one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The facility is designed to handle multiple grades of crude oil while minimizing the interface and enabling deliveries to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operational safeguards that distinguish it from other facilities at the Cushing Interchange.

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Since 1999, we have completed six separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 11 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks, twenty 270,000-barrel tanks and six 570,000-barrel tanks, all of which are used to store and terminal crude oil. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

Kerrobert Terminal. We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. In 2006, we increased the storage capacity at our Kerrobert facility by 600,000 barrels of tankage and an additional 300,000 barrels of tankage was added in 2007, bringing the total storage capacity to approximately 1 million barrels. The cost of these expansions totaled approximately \$42 million. In 2008, we commenced an additional internal growth project on the Kerrobert terminal, which will increase receipt and delivery capacity and reduce third-party costs. The cost of the project is estimated to be approximately \$43 million, of which approximately \$34 million is estimated to be incurred in 2009.

L.A. Basin. We own four crude oil and refined product storage facilities in the Los Angeles area with a total of 10 million barrels of storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. The storage facility includes 37 storage tanks. Approximately 9 million barrels of the storage capacity are in commercial service (including approximately 1 million barrels that were placed in service in 2008 at a cost of \$21 million) and 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently. We use the Los Angeles area storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. The Los Angeles area system's pipeline distribution assets connect its storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. The system is capable of loading and off-loading marine shipments at a rate of 25,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, we can deliver crude oil and feedstocks from our storage facilities to the refineries served by this system at rates of up to 6,000 barrels per hour.

Martinez and Richmond Terminals. We own two terminals in the San Francisco, California area: a terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product service). Our San Francisco area terminals currently have 56 storage tanks with approximately 5 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities that can load between approximately 4,000 and 10,000 barrels per hour of refined products. There is also a rail spur at the Richmond terminal that is able to receive products by train.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the "Mobile Terminal") that consists of seventeen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36-inch pipeline connecting the two facilities, of which approximately half of the storage capacity is included within the transportation segment.

The Mobile Terminal is equipped with a ship/tanker dock, barge dock, truck-unloading facilities and various third party connections for crude oil movements to area refiners. Additionally, the Mobile Terminal serves as a source for imports of foreign crude oil to PADD II refiners through our Mississippi/Alabama pipeline system, which connects to the Capline System at our station in Liberty, Mississippi.

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Patoka Terminal. We recently constructed three 670,000-barrel and two 400,000-barrel tanks at the Patoka Interchange located in southern Illinois. The terminal was substantially completed during the fourth quarter of 2008 at a cost of \$85 million; however, additional third-party pipeline connections remain to be completed in the first quarter of 2009, which we estimate will cost \$2 million. We anticipate Patoka to be a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. This project will have the ability to be expanded should market conditions warrant. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

Philadelphia Area Terminals. We own three refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have 42 storage tanks ranging in size from 11,000 barrels to 150,000 barrels with a combined storage capacity of approximately 3 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor, and include two dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils (heavy crude oils). The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

We are in the process of expanding the facilities by approximately 1 million barrels consisting of eight tanks ranging from 50,000 barrels to 150,000 barrels, of which three 150,000-barrel tanks were placed into service during 2008. The remaining five tanks are scheduled to be completed in the second quarter of 2009 at an estimated remaining cost of \$13 million.

St. James Terminal. In 2008, we substantially completed construction of a crude oil terminal at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. Phases I and II in aggregate consist of approximately 6 million barrels of capacity and include eleven tanks ranging from 210,000 barrels to 700,000 barrels. One tank remains to be completed early in 2009. The facility also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

New Crude Oil Storage Facilities Under Construction and Under Development

Cushing Terminal. During 2009, we will begin construction on additional crude oil tankage at our Cushing terminal. The project will include the construction of three 570,000-barrel tanks with the option to add a fourth tank during construction. This expansion is supported by long-term customer commitments. The estimated cost of construction is approximately \$46 million.

Patoka & St. James Terminals and Dock. During 2009, we will begin construction on light-product storage tankage at the Patoka and St. James terminal locations. The project will include the construction of two 300,000-barrel tanks at the Patoka terminal and three 300,000-barrel tanks at the St. James terminal. This new tankage at both facilities will complement the new dock that is currently under construction at the St. James location. The cost of the project in aggregate, including the dock, is estimated to be approximately \$167 million.

Pier 400. For a number of years, we or our predecessors have been involved in an effort to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers.

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In 2004, 2005 and 2007, we entered into or modified agreements with refiners in the Los Angeles Basin that provide long-term customer commitments to off-load a total of 200,000 barrels per day of crude oil at the Pier 400 dock. The agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability and completion of other ancillary agreements related to the project.

Due primarily to regulatory processes and delays, we have failed to meet certain project milestone dates and other economic conditions set forth in our agreements with our customers, and we are likely to miss other project objectives that are key conditions in each of our agreements.

The project involves a number of state, local and federal agencies and regulatory bodies and, accordingly, the regulatory processes are complex and interrelated with our customer negotiations. These regulatory bodies include the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. In addition, final construction of the Pier 400 project is subject to the completion of a land lease (that will include a dock construction agreement) with the Port of Los Angeles and receipt of environmental and other approvals.

The estimated cost of the project has increased significantly during the regulatory approval process due to increased service and supply costs of the original project, changes in scope of the project to meet long-term objectives of the various regulatory bodies and incremental costs associated with adapting to environmental safeguards and protections required by the governing bodies. We are in the process of completing an updated cost estimate for the Pier 400 project, but based on conditions existing in early 2009 we estimate that the project will cost approximately \$575 to \$600 million to complete, including \$47 million of costs associated with emission reduction credits and development and engineering costs incurred to date and \$41 million of estimated capitalized interest to be incurred during the construction period. This estimate is subject to change depending on various factors, including the final scope of the project and the requirements imposed through the permitting process. This cost estimate assumes the construction of 4 million barrels of storage.

Although we continue to work together with customers and regulatory bodies in an attempt to advance the project, due to the aforementioned factors as well as the impact of a weakening economic environment, we can provide no assurance that (i) the project will receive all the necessary regulatory approvals (although we know of no reason that it should not receive regulatory approvals); (ii) even if approved, the project will be constructed; or (iii) if constructed, the project will generate satisfactory economic returns.

LPG Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 133 million gallons of working capacity (approximately 100 million gallons, or approximately 2 million barrels, of useable capacity), the facility's primary assets include three salt-dome storage caverns, a 24-car rail rack and six truck racks.

Tirzah. The Tirzah facility is located in South Carolina and has an underground granite storage cavern with approximately 1 million barrels of capacity and is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline. The facility gives us a greater presence in the Southeast and we believe this facility will further support the expansion of our LPG business in North America.

LPG Processing

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of natural gas liquids ("NGL"). The primary assets

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consist of 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 8,500 barrels per day.

Natural Gas Storage Assets (owned through our 50% interest in PAA/Vulcan and operated by PAA)

Bluewater/Kimball. The Bluewater gas storage facility, which is strategically located near Detroit, Michigan, is a depleted reservoir with approximately 23 Bcf of capacity. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this approximately 3 Bcf facility to the Bluewater pipeline system. Natural gas storage facilities in the northern tier of the U.S. are traditionally used to meet seasonal demand and are typically cycled once or twice a year. Natural gas is injected during the summer months in order to provide for adequate deliverability during the peak demand winter months. Michigan is a very active market for natural gas storage as it meets nearly 75% of its peak winter demand from storage withdrawals. The Bluewater facility has direct interconnects to three major pipelines and three major natural gas utilities as well as indirect access to Dawn, a major natural gas market hub in Canada. In addition to owning these facilities, from time-to-time, PAA/Vulcan leases capacity at other facilities to augment the services it provides.

Pine Prairie. Pine Prairie Energy Center ("Pine Prairie") is a high deliverability salt dome storage facility located just northwest of Lafayette, Louisiana, approximately 50 miles from the Henry Hub in Louisiana (the delivery point for NYMEX natural gas futures contracts) near Gulf Coast supply sources and LNG import terminals. The initial phase of the facility consists of three storage caverns with a permitted working capacity of 24 Bcf and an extensive header system. Drilling operations on all three cavern wells are complete. Pine Prairie began commercial operations in October 2008 with approximately 5 Bcf of working gas storage in cavern one. Cavern two with approximately 8 Bcf of capacity is expected to be placed in service in the second quarter of 2009 followed by cavern three in the second quarter of 2010. Pine Prairie is currently connected to seven major pipelines serving the Midwest, Southeast, Mid-Atlantic and Northeast markets. Three additional pipelines are also located in the vicinity and offer the potential for future interconnects. We believe the facility's operating characteristics and strategic location position Pine Prairie to support the needs of power generators, pipelines, utilities, energy merchants and LNG re-gasification terminal operators and provide potential customers with superior flexibility in managing and balancing their natural gas requirements. In January 2007, an additional 240 acres of land were purchased adjacent to the Pine Prairie project to support future expansion activities.

Marketing Segment

Our marketing segment operations generally consist of the following merchant activities:

the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;

the storage of inventory during contango market conditions and the seasonal storage of LPG;

the purchase of refined products and LPG from producers, refiners and other marketers;

the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and

the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

We believe our marketing activities are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated

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with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a counter-cyclical balance. The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market (when the oil prices for future deliveries are higher than the current prices) or when the market switches from contango to backwardation (when the oil prices for future deliveries are lower than the current prices). See " Crude Oil Volatility; Counter-Cyclical Balance; Risk Management" for further discussion.

Except for pre-defined inventory positions, our policy is generally (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive, and (iii) not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2008, our marketing segment also owned significant volumes of crude oil and LPG classified as long-term assets for linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

8 million barrels of crude oil and LPG linefill in pipelines owned by us;

2 million barrels of crude oil and LPG linefill in pipelines owned by third parties and other long-term inventory;

528 trucks and 631 trailers; and

1,697 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from our other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment sales are based on posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. However, certain terminalling and storage rates recognized within our facilities segment are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties.

We purchase crude oil and LPG from multiple producers and believe that we have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. Marketing activities involve relatively large volumes of transactions, often with lower overall margins than transportation and facilities operations. Marketing activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

The following table shows the average daily volume of our marketing activities for the year ended December 31, 2008 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	658
Refined products sales	26
LPG sales	103
Waterborne foreign crude oil imported	80
Marketing activities total	867

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Crude Oil and LPG Purchases. We purchase crude oil in North America from producers under contracts, the majority of which range in term from a thirty-day evergreen to three-year term. We utilize our truck fleet and gathering pipelines as well as third-party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport crude oil on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. We utilize our trucking fleet as well as leased railcars and third-party tank trucks or pipelines to transport LPG.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations and barge facilities. We also purchase LPG in bulk at major pipeline terminal points and storage facilities from major oil companies, large independent producers or other LPG marketing companies. Crude oil and LPG is purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or LPG distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil and LPG Sales. The marketing of crude oil and LPG is complex and requires current detailed knowledge of crude oil and LPG sources and end markets and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and LPG to the appropriate customer.

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. The majority of these contracts are at market prices and have terms ranging from one month to three years. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. We establish a margin for the crude oil and LPG we purchase by sales for physical delivery to third party users, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, ICE or over-the-counter. 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. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices.

Crude Oil and LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade, type or volume of crude oil or LPG that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or LPG, as appropriate, with third parties. These exchanges are effected through contracts called exchange or buy/sell agreements. Through an exchange agreement, we agree to buy crude oil or LPG that differs in terms of geographic location, grade of crude oil or type of LPG, or physical delivery schedule from crude oil or LPG we have available for sale. Generally, we enter into exchanges to acquire crude oil or LPG at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts. See Note 2 to our Consolidated Financial Statements for further discussion of our accounting for exchange and buy/sell agreements.

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Credit. Our merchant activities involve the purchase of crude oil, LPG and refined products for resale and require significant extensions of credit by our suppliers. In order to assure our ability to perform our obligations under the purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit directly with us and, to a lesser extent, standby letters of credit issued under our senior unsecured revolving credit facility.

When we sell crude oil, LPG and refined products, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures.

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery, and pipeline, transportation and terminalling services also settle within 30 days from the date we issue an invoice for the provision of services.

We also have credit risk exposure related to our sales of LPG and refined products; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in amounts ranging from approximately \$2 per barrel to 100% of their contracted amounts. Generally, sales of LPG settle within 15 days of the date of invoice and refined products sales settle within 10 days.

Certain activities in our marketing segment are affected by seasonal aspects, primarily with respect to LPG marketing activities, which generally have higher activity levels during the first and fourth quarters of each year.

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil commodity prices have historically been very volatile and cyclical, and continue to reflect such a trend. For example, over the last 22 years, NYMEX WTI crude oil benchmark prices have ranged from a low of approximately \$10 per barrel during March 1986 to a high of over \$147 per barrel during July 2008. During more recent months, crude oil prices plummeted from the aforementioned high of \$147 per barrel to a five year low of less than \$33 per barrel in December 2008. Segment profit from our marketing activities is dependent on our ability to sell crude oil and LPG at prices in excess of our aggregate cost. Although segment profit may be affected during transitional periods, our crude oil marketing operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market-related indices.

Counter-Cyclical Balance

During periods when supply exceeds the demand for crude oil in the near term, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on our lease gathering margins, but is favorable to our commercial strategies that are associated with storage tankage leased from the facilities segment or from third parties. Those who control storage at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell forward at higher prices for future delivery.

When there is a higher demand than supply of crude oil in the near term, the market is backwardated, meaning that the price of crude oil for future deliveries is lower than current prices. A

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backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil as current prices are above delivery prices in the futures markets.

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our marketing segment. When the market is in contango, we will use our tankage to improve our lease gathering margins by storing crude oil we have purchased for delivery in future months that are selling at a higher price. In a backwardated market, we use less storage capacity but increased lease gathering margins provide an offset to this reduced cash flow. We believe that the combination of our lease gathering activities and the commercial strategies used with our tankage provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities in an effort to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our facilities activities and our marketing activities in transitioning crude oil markets.

Risk Management

As use of the financial markets for crude oil by producers, refiners, utilities and trading entities has increased, risk management strategies have become increasingly important in creating and maintaining margins. In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations (mainly relating to crude oil) and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments. These derivative instruments include exchange traded futures, options and swaps, 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. Our risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities are implemented in accordance with such policies. We have a risk management function that has direct responsibility and authority for our risk policies, our trading controls and procedures and certain other aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. With the exception of the controlled trading program discussed below, our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses of crude oil gathering and marketing and storage.

Our policy is generally to purchase only product for which we have a market, and to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive. Except for the controlled crude oil trading program discussed below, we do not acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our marketing activities, we may experience net unbalanced positions for short periods of time as a result of

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production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. 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 a substantially lesser amount for LPG. This controlled trading activity is monitored independently by our risk management function and must take place within predefined limits and authorizations. Such amounts exclude unhedged working inventory volumes that remain relatively constant and are subject to lower of cost or market adjustments.

Geographic Data; Financial Information about Segments

See Note 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC accounted for 14%, 19% and 14% of our revenues for each of the three years ended December 31, 2008, 2007 and 2006, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12% and 11% of our revenues for the years ended December 31, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of revenues from these customers pertain to our marketing operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins. For a discussion of customers and industry concentration risk, see Note 8 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we are exposed to significant competition based on the relatively low incremental cost of moving an incremental barrel of crude oil.

We also face competition in our marketing services and facilities services. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, investment banks that have established a trading platform, 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.

With respect to our natural gas storage operations, we compete with other storage providers, including local distribution companies ("LDCs"), utilities and affiliates of LDCs and utilities. Certain major pipeline companies have existing storage facilities connected to their systems that compete with certain of our facilities. Third-party construction of new capacity could have an adverse impact on our competitive position.

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Regulation

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue and have issued requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial penalties. At any given time there may be proposals, provisional rulings or proceedings in legislation or under governmental agency or court review that could affect our business. The regulatory burden on our assets, operations and activities increases our cost of doing business and, consequently, affects our profitability, but we do not believe that these laws and regulations affect us in a significantly different manner than our competitors. We may at any time also be required to apply significant resources in responding to governmental requests for information. The U.S. Commodity Futures Trading Commission (the "CFTC") launched a national crude oil pricing investigation in late 2007. We responded throughout 2008 to a series of requests/demands for information from the CFTC in connection with such investigation. We worked with the CFTC to focus the scope of the inquiry and limit the amount of information we were required to deliver. Within that limited scope, we believe we have completed our response. We may not know when the CFTC has completed its investigation, and the CFTC may at any time broaden the scope of inquiry and require additional information. Early in 2008, the DOT's Pipeline Hazardous Materials Safety Administration ("PHMSA") informed us that Plains had been selected among several other pipeline operators for a pilot test of a comprehensive "integrated" inspection and audit of pipeline safety compliance. We dedicated significant human resources in cooperating with PHMSA in the audit, which included a two-week long review session in our Houston office followed by field tours and records reviews in four separate operational locations. PHMSA has not yet shared its final audit conclusions. We are cooperating in a Department of Justice/Environmental Protection Agency proceeding regarding certain releases of crude oil. The proceeding could result in injunctive remedies the effect of which would subject us to operational requirements and constraints that would not apply to our competitors. See Item 3. "Legal Proceedings."

Following is a discussion of certain, but not all, of the laws and regulations affecting our operations.

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may subject us to additional operational constraints that our competitors are not required to follow. Environmental and safety laws and regulations are subject to change that may result in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by third parties. The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

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Pipeline Safety/Pipeline and Storage Tank Integrity Management

A substantial portion of our petroleum pipelines and our storage tank facilities in the United States are subject to regulation by the PHMSA pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the "HLPSA"). The HLPSA imposes safety requirements on the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPSA require pipeline operators to adopt measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines, including the maintenance of comprehensive spill response plans and the performance of extensive spill response training for pipeline personnel. These regulations also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board ("NEB") and provincial agencies.

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the DOT that require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in "high consequence areas," such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Costs associated with the inspection, testing and correction of identified anomalies were approximately \$23 million in 2008, \$15 million in 2007 and \$8 million in 2006. Based on currently available information, our preliminary estimate for 2009 is that we will incur approximately \$10 million in operational expenditures and approximately \$22 million in capital expenditures associated with our pipeline integrity management program. The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, we will continue to focus on pipeline integrity management as a primary operational emphasis. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPSA and the more recent 2002 and 2006 amendments.

On June 3, 2008, PHMSA published a final rule amending its pipeline safety regulations to extend protection to designated unusually sensitive areas or "USAs" that could be damaged by failure of certain rural onshore hazardous liquid gathering lines or low-stress pipelines. These USAs include locations containing sole-source drinking water, endangered species, or other ecological resources. Operators of rural onshore hazardous liquid gathering lines must comply with safety requirements to address threats of corrosion and third-party damage to their lines by developing a damage prevention program, complying with specified corrosion control requirements, and monitoring and mitigating conditions that could lead to internal corrosion. Moreover, the final rule narrows the regulatory exception for rural onshore low-stress hazardous liquid pipelines by extending existing safety regulations (including integrity management requirements) to certain low-stress pipelines within a defined "buffer" area around a USA. The effective date of this final rule was July 3, 2008, with operational requirements being phased in over time, generally beginning in 2009. We have less than 300 miles of pipeline subject to the new rule and do not expect compliance to have a material effect on our operating expenses.

We have expanded an internal review process in which we are reviewing the condition and operating history of certain pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from Environmental Protection Agency ("EPA") enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines.

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States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations.

The DOT has issued guidelines with respect to securing regulated facilities against terrorist attack. We have instituted security measures and procedures in accordance with such guidelines to enhance the protection of certain of our facilities. We cannot provide any assurance that these security measures would fully protect our facilities from a concentrated attack.

The DOT has adopted American Petroleum Institute Standard 653 ("API 653") as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance, subject to an applicable waiver or stay, is required in May 2009. Costs associated with this program were approximately \$41 million, \$18 million and \$7 million in 2008, 2007 and 2006, respectively. Based on currently available information, we anticipate we will spend approximately \$32 million in 2009 in connection with API 653 compliance activities. Certain storage tanks may be taken out of service if we believe the cost of upgrades will exceed the value of the storage tanks or replacement tankage may be constructed at a more optimal location. In addition, due primarily to decreased crude oil consumption, market conditions during the first part of 2009 have resulted in a significant demand for storage capacity. Accordingly, we may elect to spend more in 2009 than initially forecasted if economic conditions warrant.

In Canada, the NEB and provincial agencies such as the Energy Resources Conservation Board ("ERCB") in Alberta and the Saskatchewan Ministry of Energy and Resources regulate the construction, alteration, inspection and repair of crude oil storage tanks. We expect to incur costs under laws and regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. We spent approximately \$8 million in 2008, \$6 million in 2007 and \$5 million in 2006. Our preliminary estimate for 2009 is approximately \$20 million. Certain of these costs are recurring in nature and thus will affect future periods.

Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation. 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 the regulatory standards in the U.S. and Canada.

Occupational Safety and Health

We are subject to the requirements of the Occupational Safety and Health Act, as amended ("OSHA") and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances.

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. Additionally, under the Criminal Code of Canada, organizations, corporations and individuals may be prosecuted criminally for violating the duty to protect employee and public safety.

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We believe that our operations are in substantial compliance with applicable occupational health and safety requirements.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, ("RCRA") and analogous state and provincial laws. We are not required to comply with a substantial portion of the RCRA requirements because our operations generate primarily oil and gas wastes, which currently are excluded from consideration as RCRA hazardous wastes. It is possible, however, that in the future oil and gas wastes may be included as RCRA hazardous wastes, in which event our wastes as well as the wastes of our competitors will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses.

Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA's definition of a "hazardous substance." We have knowledge of two Superfund sites where an affiliate (Scurlock Permian LLC) of a predecessor owner (Marathon Ashland Petroleum or "MAP") of assets we now own was alleged to have deposited waste oils, but MAP has contractually indemnified us for any liabilities associated with these two sites. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment.

Environmental Remediation

We currently own or lease, and in the past have owned or leased, properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated wastes disposed thereon may be subject to CERCLA, RCRA and state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated wastes (including wastes disposed of or released by prior owners or operators) and to clean up contaminated property (including contaminated groundwater).

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In conjunction with our acquisitions, we make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will

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apply, and have term and total dollar limits. For instance, in connection with the purchase of former Texas New Mexico ("TNM") pipeline assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of \$20 million, of which we agreed in an arrangement with TNM to bear the first \$11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of \$20 million (excluding certain deductibles). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). As of December 31, 2008, we had incurred approximately \$9 million of remediation costs associated with these sites, while SOP's share is approximately \$5 million. In another example, as a result of our merger with Pacific, we assumed liability for a number of ongoing remediation sites associated with releases from pipeline or storage operations. We have evaluated each of the sites requiring remediation and developed reserve estimates for the Pacific sites, which total approximately \$21 million. See Item 3. "Legal Proceedings."

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a \$100,000 deductible per site, an aggregate coverage limit of \$70 million, and expires in 2012.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

Air Emissions

Our operations are subject to the U.S. Clean Air Act ("Clean Air Act") and comparable state and provincial laws. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources already constructed. We may be required to incur certain capital and operating expenditures in the next several years to install air pollution control equipment and otherwise comply with more stringent state and regional air emissions control when we attempt to obtain or maintain permits and approvals for sources of air emissions. Although we believe that our operations are in substantial compliance with these laws in the areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Climate Change Initiatives

In response to recent studies suggesting that emissions of carbon dioxide, methane and certain other gases may be contributing to warming of the Earth's atmosphere, many nations, including Canada, have agreed to limit emissions of these gases, generally referred to as greenhouse gases ("GHG"), pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." The Kyoto Protocol requires Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012. In response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (the "Regulatory Framework") for regulating air pollution and industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to become effective in 2010.

Although the United States is not participating in the Kyoto Protocol, the U.S. Congress has been actively considering legislation to reduce emissions of GHGs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of GHGs, primarily through the development of GHG emission inventories and/or regional GHG cap and trade programs. Also, on April 2, 2007, the U.S. Supreme Court in *Massachusetts, et al. v. EPA* held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act and that EPA must consider whether it is required to regulate GHG emissions from mobile sources such as cars and trucks. Moreover, the Court's holding in *Massachusetts* that GHGs fall under the federal Clean Air Act's

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definition of "air pollutant" also may result in future regulation of GHG emissions from stationary sources such as refineries and power plants. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of GHG emissions under the Clean Air Act, in response to the Supreme Court's decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of GHGs under the Clean Air Act and other potential methods of regulating GHGs. Although the notice did not propose any specific, new regulatory requirements for GHGs, it indicates that federal regulation of GHG emissions could occur in the near future. Thus, there may be restrictions imposed on the emission of GHGs if Congress does not adopt new legislation specifically addressing emissions of GHGs.

Operational components of our stationary facilities that require the combustion of carbon-based fuel (such as compression stations, line heaters and internal combustion engine-driven pumps) produce GHG emissions in the form of CO₂. Although we believe that these emissions in the aggregate are not significant relative to other industries that are fuel-combustion intensive, we have commenced a process of identifying potential emission sources and establishing GHG inventories for such sources.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows.

Water

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act ("CWA") and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See " Pipeline Safety/Pipeline and Storage Tank Integrity Management" and Note 11 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The Oil Pollution Act of 1990 ("OPA") amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill. We believe that we are in substantial compliance with applicable OPA requirements. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such federal, state and Canadian requirements.

Other Regulation

Transportation Regulation

Our transportation activities are subject to regulation by multiple governmental agencies. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. The following is a summary of the types of transportation regulation that may impact our operations.

General Interstate Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act ("ICA"). The ICA requires that tariff rates for petroleum pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory.

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State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies, including the California Public Utility Commission, which prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities. See Note 13 to our Consolidated Financial Statements.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the Alberta ERCB. With respect to a pipeline over which it has jurisdiction, the relevant regulatory authority has the power, upon application by a third party, to determine the rates we are allowed to charge for transportation on, and set other terms of access to, such pipeline. In such circumstances, if the relevant regulatory authority determines that the applicable terms and conditions of service are not just and reasonable, the regulatory authority can impose conditions it considers appropriate.

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In June 2008, the Minerals Management Service issued a final rule establishing formal and informal complaint procedures for shippers that believe they have been denied open and nondiscriminatory access to transportation on the OCS. We do not expect the rule to have a material impact on our operations or results.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 ("EPAct"), which, among other things, required the FERC to issue rules to establish a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by establishing a methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index (currently, the producer price index for finished goods plus 1.3 percent). Pipelines are allowed to raise their rates to the rate ceiling level generated by application of the index. If the methodology reduces the ceiling level such that it is lower than a pipeline's filed rate, the pipeline must reduce its rate to conform with the lower ceiling unless doing so would reduce a rate "grandfathered" by EPAct (see below) to below the grandfathered level. A pipeline must, as a general rule, use the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, agreement with an unaffiliated shipper, and settlement as alternatives to the indexing approach that may be used in certain specified circumstances. The FERC's indexing methodology is subject to review every five years; the current methodology will remain in place through June 30, 2011. Because the indexing methodology is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

Under the EPAct, petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct are deemed to be just and reasonable under the ICA, if such rates had not been subject to complaint, protest or investigation during that 365-day period. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline or in the nature of the services provided that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential. Litigation is ongoing at FERC regarding the methodology to be applied for determining whether there has been "substantial change" under EPAct. We have no way of knowing what result FERC will reach in these proceedings.

FERC permits entities owning public utility assets, including oil pipelines, to include an income tax allowance in their cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. A tax pass-through entity such as a master limited partnership ("MLP") seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility

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income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the FERC's current income tax allowance policy is generally favorable for pipelines that are organized as pass-through entities, such as MLPs, it still entails rate risk due to the case-by-case review requirement. FERC continues to refine its tax allowance policy in case-by-case reviews; how the tax allowance policy is applied in practice to pipelines owned by MLPs could affect the rates of pipelines regulated by FERC.

Our Pipelines. The FERC generally has not investigated rates on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. Substantially all of our transportation segment profit is produced by rates that are either grandfathered or set by agreement with one or more shippers.

Trucking Regulation

We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety, and many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment, facility inspection, reporting and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, including importation of crude oil between the United States and Canada, we are subject to a variety of legal requirements pertaining to such activities including export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, tariff and tax reporting requirements or failure to provide certifications relating to toxic substances could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state, provincial and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Natural Gas Storage Regulation

Interstate Regulation. The interstate storage facilities in which we have an investment are or will be subject to rate regulation by the FERC under the Natural Gas Act. The Natural Gas Act requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored for U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. The FERC has granted market-based rate authority under its existing regulations to PAA/Vulcan's Pine Prairie Energy Center and to its Bluewater gas storage facility.

The FERC also has authority over the construction and operation of U.S. transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, FERC's authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and

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discontinuation of services and relationships between pipelines and storage companies and certain affiliates.

Standards of Conduct for Transmission Providers. Historically, FERC's standards of conduct regulations (now vacated) generally restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by U.S. storage facility operators to their affiliated gas marketing entities. The standards of conduct did not apply, however, to natural gas storage providers authorized to charge market-based rates that (i) were not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, and (ii) had no exclusive franchise area, no captive ratepayers, and no market power. In January of 2006, the FERC found that PAA/Vulcan's Pine Prairie Energy Center qualified for this exemption from the standards of conduct.

On November 17, 2006, the D.C. Circuit vacated the standards of conduct regulations with respect to natural gas pipelines and storage companies, and remanded the matter to the FERC. Following a notice of proposed rulemaking, on October 16, 2008, the FERC issued its revised Standards of Conduct for Transmission Providers ("Standards of Conduct"). The Standards of Conduct continue to exempt natural gas storage providers like PAA/Vulcan's Pine Prairie Energy Center and its Bluewater facility. However, requests for rehearing of the October 16, 2008 order are pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

On November 20, 2008, the FERC issued a final rule that requires interstate pipelines and certain non-interstate facilities to post certain daily capacity and volume information. The rule extends to storage facilities (such as Bluewater) that provide no-notice service. The rule has been appealed, but pending the results of that appeal, Bluewater will have a requirement to post volumes with respect to no-notice service flows at each receipt and delivery point.

Energy Policy Act of 2005. On January 19, 2006, the FERC issued Order No. 670, which implements the anti-manipulation provision of EPCRA 2005. Pursuant to EPCRA 2005 and Order No. 670, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of the FERC to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPCRA 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act up to \$1,000,000 per day per violation for violations occurring after August 8, 2005. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC's Natural Gas Act enforcement authority.

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment 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. Since the time we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 1,500% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available

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insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, we cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. 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, or that we have established adequate reserves to the extent that such risks are not insured.

Title to Properties and Rights-of-Way

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

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property and, in some instances, such rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some cases, property for pipeline purposes was purchased in fee. All of the pump stations are located on property owned in fee or property under leases. In certain states and under certain circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

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Some of the leases, easements, rights-of-way, permits and licenses transferred to us, upon our formation in 1998 and in connection with acquisitions we have made since that time, required the consent of the grantor to transfer such rights, which in certain instances is a governmental entity. We believe that we have obtained such third party consents, permits and authorizations as are sufficient for the transfer to us of the assets necessary for us to operate our business in all material respects as described in this report. With respect to any consents, permits or authorizations that have not yet been obtained, we believe that such consents, permits or authorizations will be obtained within a reasonable period, or that the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed 3,302 employees at December 31, 2008. None of the employees of our general partner were subject to a collective bargaining agreement, except for eight employees covered by one agreement and another eight employees covered by another agreement. Both collective bargaining agreements are scheduled for renegotiation in September 2009. Our general partner considers its employee relations to be good.

Summary of Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner's individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, states and localities, including the Canadian provinces and Canada, of the unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the unitholder.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the "Code"), which we must meet each year. The owners of our common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no U.S. federal income taxes, and a common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held. In certain cases, we are subject to, or have paid Canadian income and withholding taxes. Canadian withholding taxes are due on intercompany interest payments and credits and dividend payments.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership (including, with respect to the general partner, its incentive distribution right), as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. In determining a unitholder's federal income tax liability, the unitholder is required to take into account the unitholder's share of income generated by us for each taxable year of the Partnership ending with or within the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. Any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

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Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder's share of our nonrecourse liabilities. A unitholder's basis is generally increased by the unitholder's share of our income and by any increases in the unitholder's share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder's share of our losses and distributions (including deemed distributions due to a decrease in the unitholder's share of our nonrecourse liabilities).

Limitations on Deductibility of Partnership Losses

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely held corporations), any partnership losses generated by us are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused or suspended by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder's common units in a taxable transaction with an unrelated party.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Foreign, State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as foreign, state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. We own property and conduct business in Canada as well as in most states in the United States. A unitholder will therefore be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned through partnership entities. A unitholder may also be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to a particular state, may not relieve the unitholder from the

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obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a nonresident alien, foreign corporation or other foreign person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding.

Available Information

We make available, free of charge on our Internet website (<http://www.paalp.com>), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission.

Item 1A. Risk Factors

Risks Related to Our Business

Certain Risks are Amplified by the Current Economic Environment

During 2007, the U.S. and many key countries began to exhibit signs of economic weakness, which continued throughout 2008 and into 2009. This weakness had a severe adverse impact on the global financial system, stressing a number of large financial institutions to the point of failure, merger or requiring government assistance and resulting in a severe reduction in available capital. Capital constraints coupled with significant energy price volatility have produced pervasive liquidity issues for many companies. Such events have created pronounced uncertainty in the economic outlook, and have amplified the potential impact and likelihood of occurrence of certain risks inherent in our business. Such amplified risks include:

Increased cost of capital and increased difficulties accessing capital to fund expansion and acquisition activities as well as routine operating requirements;

The inability or unwillingness of lenders to honor their contractual commitments;

The failure of customers to timely or fully pay amounts due to us;

The failure of suppliers to pay third parties under obligations for which we have potential contingent liabilities;

The potential for adverse actions by rating agencies;

Potentially adverse changes in tax laws;

The failure of counterparties to fulfill their delivery or purchase obligations;

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Business failures by vendors, suppliers or customers that result in (i) delays in progress on our capital projects, (ii) nonpayment of receivables or (iii) expensive and protracted court or bankruptcy proceedings;

Increased criminal activities, including fraud, theft, vandalism and random violence that could affect our assets or business activities; and

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Decreases in domestic consumption or in volumes imported to or produced in the United States and related reductions in transportation, terminalling or marketing margins.

We may not be able to fully implement or capitalize upon planned growth projects.

We have a number of organic growth projects that require the expenditure of significant amounts of capital, including the Pier 400 project, the Pine Prairie joint venture, the Cushing, St. James and Patoka terminal and dock projects. Many of these projects involve numerous regulatory, environmental, commercial, weather-related, political and legal uncertainties that will be beyond our control. As these projects are undertaken, required approvals may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects. Moreover, revenues associated with these organic growth projects will not increase immediately upon the expenditures of funds with respect to a particular project and these projects may be completed behind schedule or in excess of budgeted cost. We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes. As a result of these uncertainties, the anticipated benefits associated with our capital projects may not be achieved.

Loss of credit rating or the ability to receive open credit could negatively affect our ability to use the counter-cyclical aspects of our asset base or to capitalize on a volatile market.

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties, including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counterparties. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, including the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the oil until the time we complete the sale of the oil.

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

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

In those cases in which 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.

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil we purchase 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, ICE 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 generally not to acquire and hold physical inventory, futures contracts or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. We are also exposed to

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basis risk when crude oil is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil and a substantially lesser amount for LPG. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately \$181 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.

The nature of our business and assets exposes us to significant compliance costs and liabilities. Our asset base has more than tripled within the last four years. As we add assets, we historically have experienced a corresponding increase in the relative number of releases of crude oil into the environment. Although we believe we have reduced the trend, additional assets acquired in the future could again result in increased frequency of releases. Substantial expenditures may be required to maintain the integrity of aged and aging pipelines and terminals at acceptable levels.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may subject us to additional operational requirements and constraints, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency. Any such change or interpretation adverse to us could have a material adverse effect on our operations, revenues and profitability.

Today we own approximately twice the miles of pipeline we owned five years ago. We have also increased our terminalling and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. As we have expanded our asset base, we historically have observed an increase in the number of releases of liquid hydrocarbons into the environment. Although we believe that our integrity management efforts (discussed below) have been successful in reversing that trend, the future acquisition of assets could once again result in an increase in the overall number of releases. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. During 2006 and 2007, we acquired refined products pipeline and terminalling assets. These assets are also subject to significant compliance costs and liabilities. In addition, because of their increased volatility and tendency to migrate farther and faster than crude oil, releases of refined products into the environment can have a more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act, enacted in December 2006, requires the DOT to issue regulations for

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certain pipelines that were not previously subject to regulation. These new regulations, adopted in July 2008, include requirements for the establishment of additional pipeline integrity management programs. See Items 1 and 2. "Business and Properties Regulation Environmental, Health and Safety Regulation Pipeline Safety/Pipeline and Storage Tank Integration Management."

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2008 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from EPA enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures. See Item 3. "Legal Proceedings Environmental."

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. A shut-in of this production due to economic limitations or a significant event could adversely affect our profitability. In addition, these offshore fields have experienced substantial production declines since 1995.

A significant portion of our transportation segment profit is derived from pipeline transportation tariff associated with the Santa Ynez and Point Arguello fields located offshore California and the onshore fields in the San Joaquin Valley. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. In addition, any significant production disruption from OCS fields and the San Joaquin Valley due to production problems, transportation problems, earthquakes or other reasons could have a material adverse effect on our business. We estimate that a 5,000 barrel per day decline in volumes shipped from these OCS fields would result in a decrease in annual transportation segment profit of approximately \$7 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated \$3 million decrease in annual transportation segment profit.

Our profitability depends on the volume of crude oil, refined product and LPG shipped, purchased and gathered.

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.

To maintain the volumes of crude oil we purchase in connection with our operations, 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. 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 relationships already exist between producers and other gatherers and purchasers of crude oil.

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Fluctuations in demand can negatively affect our operating results.

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. 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.

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 transportation 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.

If we do not make acquisitions on economically acceptable terms, our future growth may be limited.

Our ability to grow our distributions depends in part on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with the sellers, (ii) unable to raise financing for such acquisitions on economically acceptable terms or (iii) outbid by competitors, our future growth will be limited. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

In evaluating acquisitions, we generally prepare one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although we expect a reasonable basis will exist for those assumptions, the assumptions will generally involve current estimates of future conditions, which are difficult to predict. Realization of many of the assumptions will be beyond our control. Moreover, the uncertainty and risk of inaccuracy associated with any financial projection will increase with the length of the forecasted period. Some acquisitions may not be accretive in the near term, and will be accretive in the long term only if we are able timely and effectively to integrate the underlying assets and such assets perform at or near the levels anticipated in our acquisition projections.

Our growth strategy requires access to new capital. Tightened capital markets or other factors that increase our cost of capital could impair our ability to grow.

We continuously consider potential acquisitions and opportunities for internal growth. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition or internal growth project will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could affect our cost of capital as well as our ability to execute our growth strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

performance from the acquired businesses or assets that is below the forecasts we used in evaluating the acquisition;

a significant increase in our indebtedness and working capital requirements;

the inability to timely and effectively integrate the operations of recently acquired businesses or assets;

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the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;

risks associated with operating in lines of business that are distinct and separate from our historical operations;

customer or key employee loss from the acquired businesses; and

the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions or meet our debt service requirements.

Our results of operations are influenced by the overall forward market for crude oil, and certain market structures or the absence of pricing volatility may adversely impact our results.

Results from our marketing segment are influenced by the overall forward market for crude oil. A contango market (meaning that the price of crude oil for future deliveries is higher than current prices) is favorable to commercial strategies that are associated with storage tankage as it allows a party to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. Wide contango spreads combined with price structure volatility generally have a favorable impact on our results. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) has a positive impact on lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures are referred to as transition periods. If the market is in a backwardated to transitional structure, our results from our marketing segment may be less than those generated during the more favorable contango market conditions. Additionally, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the least beneficial environment for our marketing segment.

Our assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our U.S. and Canadian pipeline system may reduce the amount of cash we generate.

Our U.S. interstate common carrier pipelines are subject to regulation by the FERC under the ICA. The ICA requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. We are also subject to the Pipeline Safety Regulations of the DOT. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

For our U.S. interstate common carrier pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings, or the FERC can investigate on its own initiative. Under certain circumstances, the FERC could limit our ability to set rates based on our costs, or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Natural gas storage facilities are subject to regulation by the FERC and certain state agencies. A change in PAA/Vulcan's rate structure could adversely affect its revenues.

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Our Canadian pipelines are subject to regulation by the NEB and by provincial authorities. Under the National Energy Board Act, the NEB could investigate the tariff rates or the terms and conditions of service relating to a jurisdictional pipeline on its own initiative upon the filing of a toll or tariff application, or upon the filing of a written complaint. If it found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the NEB could require us to change our rates, provide access to other shippers, or change our terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or our terms and conditions of service relating to our provincially regulated proprietary pipelines. If it found our rates or terms of service to be contrary to statutory requirements, it could impose conditions it considers appropriate. A provincial authority could declare a pipeline to be a common carrier pipeline, and require us to change our rates, provide access to other shippers, or otherwise alter our terms of service. Any reduction in our tariff rates would result in lower revenue and cash flows.

Some of our operations cross the U.S./Canada border and are subject to cross border regulation.

Our cross border activities with our Canadian subsidiaries subject us to regulatory matters, including import and export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Such regulations include the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

We face competition in our transportation, facilities and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, investment banks, 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.

With respect to our interest in PAA/Vulcan's natural gas storage operations, we compete with other storage providers, including LDCs, utilities and affiliates of LDCs and utilities. Certain major pipeline companies have existing storage facilities connected to their systems that compete with certain of PAA/Vulcan's facilities. Third-party construction of new capacity could have an adverse impact on PAA/Vulcan's competitive position.

We may in the future encounter increased costs related to, and lack of availability of, insurance.

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. We can give no assurance that we will be able to maintain adequate insurance in the future at rates we consider reasonable. The occurrence of a significant event not fully insured could materially and adversely affect our operations and financial condition.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities. In addition, our future debt level may limit our future financial and operating flexibility.

As of December 31, 2008, our consolidated debt outstanding was approximately \$4.3 billion, consisting of approximately \$3.3 billion principal amount of long-term debt (including senior notes) and approximately \$1.0 billion of short-term borrowings. As of December 31, 2008, we had approximately \$1.0 billion of available borrowing capacity under our senior unsecured revolving credit facility and our senior secured hedged inventory facility.

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The amount of our current or future indebtedness could have significant effects on our operations, including, among other things:

a significant portion of our cash flow will be dedicated to the payment of principal and interest on our indebtedness and may not be available for other purposes, including the payment of distributions on our units and capital expenditures;

credit rating agencies may view our debt level negatively;

covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

we may be at a competitive disadvantage relative to similar companies that have less debt; and

we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our credit agreements 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, and sell substantially all of our assets or enter into a merger or consolidation. Our credit facility treats a change of control as an event of default and also requires us to maintain a certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Sources of Liquidity Credit Facilities and Long-Term Debt."

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

Marine transportation of crude oil and refined product has inherent operating risks.

Our gathering and marketing operations include purchasing crude oil that is carried on third-party tankers. Our waterborne cargoes of crude oil are at risk of being damaged or lost because of events such as marine disaster, bad weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues from or termination of charter contracts, governmental fines, penalties or restrictions

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on conducting business, higher insurance rates and damage to our reputation and customer relationships generally. Although certain of these risks may be covered under our insurance program, any of these circumstances or events could increase our costs or lower our revenues.

Maritime claimants could arrest the vessels carrying our cargoes.

Crew members, suppliers of goods and services to a vessel, other shippers of cargo and other parties may be entitled to a maritime lien against that vessel for unsatisfied debts, claims or damages. In many jurisdictions, a maritime lienholder may enforce its lien by arresting a vessel through foreclosure proceedings. The arrest or attachment of a vessel carrying a cargo of our oil could substantially delay our shipment.

In addition, in some jurisdictions, under the "sister ship" theory of liability, a claimant may arrest both the vessel that is subject to the claimant's maritime lien and any "associated" vessel, which is any vessel owned or controlled by the same owner. Claimants could try to assert "sister ship" liability against one vessel carrying our cargo for claims relating to a vessel with which we have no relation.

We are dependent on use of third-party assets for certain of our operations.

Certain of our business activities require the use of third-party assets over which we may have little or no control. For example, a portion of our storage and distribution business conducted in the Los Angeles basin (acquired in connection with the Pacific merger) receives waterborne crude oil through dock facilities operated by a third party in the Port of Long Beach. We are currently a hold-over tenant with respect to such facilities. If we are unable to renew the agreement that allows us to utilize these dock facilities, and if other alternative dock access cannot be arranged, the volumes of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

Increases in interest rates could adversely affect our business and the trading price of our units.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facilities. As of December 31, 2008, we had approximately \$4.3 billion of consolidated debt, of which approximately \$3.1 billion was at fixed interest rates and approximately \$1.2 billion was at variable interest rates (including \$80 million of interest rate derivatives that swap fixed-rate debt for floating). From time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our marketing segment results by increasing interest costs associated with the storage of hedged crude oil and LPG inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

Changes in currency exchange rates could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations. For example, the financial market turmoil, which started in 2007 and continued through 2008, impacted the exchange rate, specifically within the latter portion of 2008. The average monthly exchange rate for the Canadian dollar to U.S. dollar ranged between \$1.00:1 and \$1.06:1 during the first nine months of 2008, but spiked to a range between \$1.18:1 and \$1.23:1 during the fourth quarter of 2008.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist

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organizations. These developments will subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

An impairment of goodwill could reduce our earnings.

At December 31, 2008, we had \$1.2 billion of goodwill, of which we recorded approximately \$875 million upon completion of our merger with Pacific. The purchase price for the Pacific merger was approximately \$2.5 billion. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our remaining balance of goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity and increase in balance sheet leverage as measured by debt to total capitalization.

PAA/Vulcan's natural gas storage facilities are new and have limited operating history.

Although we believe that PAA/Vulcan's operating natural gas storage facilities are designed substantially to meet PAA/Vulcan's contractual obligations with respect to injection and withdrawal volumes and specifications, the facilities are new and have a limited operating history. If PAA/Vulcan fails to receive or deliver natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, PAA/Vulcan could incur significant costs to maintain compliance with PAA/Vulcan's contracts.

We have a limited history of operating natural gas storage facilities and transporting, storing and marketing refined products.

We may enter into lines of business that are distinct and separate from our historical operations and that involve different commercial, operational and regulatory issues. For example, although many aspects of the natural gas storage and refined products industries are similar to our crude oil operations, our current management had little experience in operating natural gas storage facilities or refined products assets prior to our acquisition of such assets. There are significant risks and costs inherent in our efforts to engage in these operations, including the risk that we might not be able to implement our operating policies and strategies successfully. The devotion of capital, management time and other resources to unfamiliar operations could adversely affect our existing business.

Joint venture and other investment structures can create operational difficulties.

Our natural gas storage operations are conducted through PAA/Vulcan, a joint venture between us and a subsidiary of Vulcan Capital Private Equity I LLC. We are also engaged in an investment arrangement with Settoon Towing. Joint venture arrangements typically include provisions designed to allow each venturer to participate at some level in the management of the venture and to protect such venturer's investment.

As a result, differences in views among the venture participants may result in delayed decisions or in failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the venture. Accordingly, delayed decisions and failures to agree can potentially adversely affect the business and operations of the ventures and in turn our business and operations.

From time to time, enterprises in which we have interests may be involved in disputes or legal proceedings which, although not involving a loss contingency to us, may nonetheless have the potential to negatively affect our investment. For example, Settoon Towing is party to a lawsuit involving

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allegations that a Settoon barge struck a wellhead, causing the release of oil into the Intracoastal Canal.

Risks Inherent in an Investment in Plains All American Pipeline, L.P.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf (other than expenses related to the Class B units of Plains AAP, L.P.). The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

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

Because distributions on our 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 record profits.

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates the Partnership. Unlike the holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66²/₃% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

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

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We may issue additional common units without unitholder approval, which would dilute a unitholder's existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units without unitholder approval (subject to applicable NYSE rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

an existing unitholder's proportionate ownership interest in the Partnership will decrease;

the amount of cash available for distribution on each unit may decrease;

the relative voting strength of each previously outstanding unit may be diminished; and

the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

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In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;

the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;

the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and

the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. Any new owner of our general partner would be able to replace the board of directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under the indentures governing certain issues of our senior notes and under our revolving credit agreement. An event of default under certain of our indentures could require us to make an offer to purchase the senior notes issued thereunder at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us under our revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

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Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the notes.

Our debt securities are effectively subordinated to claims of our secured creditors and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although substantially all of our operating subsidiaries, other than minor subsidiaries and those regulated by the California Public Utilities Commission, have guaranteed such debt securities, the guarantees are subject to release under certain circumstances, and we may have subsidiaries that are not guarantors. In that case, the debt securities would be effectively subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the debt securities.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners' capital. At December 31, 2008, our total outstanding debt was approximately \$4.3 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities 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.

Our leverage could have important consequences to investors in our debt securities. We will require substantial cash flow to meet our principal and interest obligations with respect to the notes and our other consolidated indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our bank credit facility to service our indebtedness, although the principal amount of the notes will likely need to be refinanced at maturity in whole or in part. However, a significant downturn in the hydrocarbon industry or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or portion of our debt or sell assets. We can give no assurance that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

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A court may use fraudulent conveyance considerations to avoid or subordinate the subsidiary guarantees.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. A court may use fraudulent conveyance laws to subordinate or avoid the subsidiary guarantees of our debt securities issued by any of our subsidiary guarantors. It is also possible that under certain circumstances a court could hold that the direct obligations of a subsidiary guaranteeing our debt securities could be superior to the obligations under that guarantee.

A court could avoid or subordinate the guarantee of our debt securities by any of our subsidiaries in favor of that subsidiary's other debts or liabilities to the extent that the court determined either of the following were true at the time the subsidiary issued the guarantee:

that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or

that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:

was insolvent or rendered insolvent by reason of the issuance of the guarantee;

was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or

intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation, or if the present fair saleable value of its assets were less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and matured.

Among other things, a legal challenge of a subsidiary's guarantee of our debt securities on fraudulent conveyance grounds may focus on the benefits, if any, realized by that subsidiary as a result of our issuance of our debt securities. To the extent a subsidiary's guarantee of our debt securities is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of our debt securities would cease to have any claim in respect of that guarantee.

The ability to transfer our debt securities may be limited by the absence of a trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development or liquidity of any market for the debt securities.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make required payments on our debt securities depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state

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partnership laws and other laws and regulations. Pursuant to the credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the debt securities, or to repurchase the debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of the debt securities. We cannot assure you that we would be able to refinance the debt securities.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt securities or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our available cash to our unitholders of record and our general partner. Available cash is generally all of our cash receipts adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating partnerships in amounts the general partner determines in its reasonable discretion to be necessary or appropriate:

to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);

to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or

to comply with applicable law or any of our loan or other agreements.

Although our payment obligations to our unitholders are subordinate to our payment obligations to debtholders, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to additional amounts of entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available to pay distributions and our debt obligations.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions or to pay our debt obligations would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in cash flow and after-tax returns to our unitholders, likely causing a substantial reduction in the value of our units.

Current law may change causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, beginning in 2008, we became subject to a new entity level tax on the portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us will reduce the cash available for distribution to our unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise

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subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

Recent changes in Canadian tax law will subject our Canadian subsidiaries to entity-level tax, which will reduce the amount of cash available to pay distributions and our debt obligations.

In June 2007, the Canadian government passed legislation that imposes entity-level taxes on certain types of flow-through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. We believe that we are currently within the normal growth guidelines as defined in the legislation, which should delay the effective date until 2011. However, future acquisitions could be subject to an entity-level tax prior to 2011. Entity-level taxation of our Canadian flow-through entities will reduce cash available for distributions or to pay debt obligations.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in our termination as a partnership for federal income tax purposes.

We will be considered to have been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution or debt service.

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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Tax gain or loss on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their common units, the amount of any such prior excess distributions with respect to their units will, in effect, become taxable income to the unitholder if the common units are sold at a price greater than the unitholder's tax basis in those common units, even if the price the unitholder receives is less than the unitholder's original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisor before investing in our common units.

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

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

Our unitholders will likely be subject to state, local and foreign taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state, local and foreign taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in most states in the United States and Canada, most of which impose a personal income tax on individuals and an income tax on corporations and other entities. It is our unitholders' responsibility to file all U.S. federal, state, local and foreign tax returns.

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We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there is no tax concept of loaning a partnership interest, a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

The tax treatment of (i) publicly traded partnerships or (ii) an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of (i) publicly traded partnerships, including us, or (ii) an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Although the considered legislation would not have appeared to have affected our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

Our method of proration of items of income, gain, loss and deduction between transferors and transferees may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the EPA, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately \$4 million to \$5 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the "DOJ") for further investigation in connection with a civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with the DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that the EPA could assess with respect to the subject releases under relevant statutes would be approximately \$6.8 million. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude Bankruptcy. We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately \$62 million. We intend to vigorously defend our contractual and statutory rights.

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On November 15, 2006, we completed the Pacific merger. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC ("PPS"). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when the pipeline was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately \$26 million, substantially all of which have been incurred and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, in March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four-count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleged the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. On October 15, 2008 this criminal action (all four counts) was dismissed with prejudice and PPS was not subjected to any fine or penalty.

In September 2008, PPS was served by the State of California with a civil complaint in connection with this release, in the Los Angeles Superior Court Case No. BC398627, alleging violations of the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, violations of two sections of the California Water Code for the unlawful discharge of waste into state waters without a permit, and violations of the Public Nuisance Code alleging that discharge of petroleum into waters of the state had created a public nuisance. This case was settled in October 2008. Pursuant to the terms of the settlement agreement, PPS paid no fine or penalty, but made civil settlement payments to various agencies of the State of California in the total amount of approximately \$1.1 million.

United States of America v. Pacific Pipeline System, LLC. In September 2008, the EPA filed a civil complaint against PPS in connection with the Pyramid Lake release. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV08-5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately \$3.7 million. The EPA and DOJ have discretion to reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the alleged offenses cannot be ascertained. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We will defend against these charges. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty or fine that might be imposed by the EPA and DOJ, and intend to pursue discussions with the EPA and DOJ regarding such defenses and mitigating circumstances and factors. Although we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ on behalf of the EPA to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE (and other petroleum product) contamination at the Pacific Atlantic Terminals LLC ("PAT") facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to \$10 million. Both Exxon and GATX were prior owners of the terminal. We contend that Exxon and GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific's purchase of the facility. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity

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and contribution. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in mitigative costs or the imposition of fines and penalties. We have, for instance, recently settled numerous air permit violations alleged by the Bay Area Air Quality Management District.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to help prevent releases, damages and liabilities incurred due to any such releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. See Items 1 and 2. "Business and Properties Regulation Environmental, Health and Safety Regulation Pipeline Safety/Pipeline and Storage Tank Integration Management." However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas. See " Pipeline Releases" above.

At December 31, 2008, our reserve for environmental liabilities totaled approximately \$42 million, of which approximately \$8 million is classified as short-term and \$34 million is classified as long-term. At December 31, 2008, we have recorded receivables totaling approximately \$4 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

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Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. 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 overall trend in the environmental insurance industry 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 environmental 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 environmental activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

Table of Contents**PART II****Item 5. Market For Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities**

Our common units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "PAA." On February 20, 2009, the closing market price for our common units was \$37.23 per unit and there were approximately 90,000 record holders and beneficial owners (held in street name). As of February 20, 2009, there were 122,911,645 common units outstanding.

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

	Common Unit Price Range		Cash Distributions ⁽¹⁾
	High	Low	
2008			
4th Quarter	\$42.39	\$23.25	\$ 0.8925
3rd Quarter	48.36	35.68	0.8925
2nd Quarter	50.96	44.54	0.8875
1st Quarter	52.44	43.93	0.8650
2007			
4th Quarter	\$57.09	\$46.25	\$ 0.8500
3rd Quarter	65.24	52.01	0.8400
2nd Quarter	64.82	56.32	0.8300
1st Quarter	59.33	49.56	0.8125

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter.

Our common units are used as a form of compensation to our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. "Certain Relationships and Related Transactions, and Director Independence."

Cash Distribution Policy

We will distribute all of our available cash to our unitholders on a quarterly basis in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

provide for the proper conduct of our business;

comply with applicable law or any partnership debt instrument or other agreement; or

provide funds for distributions to unitholders and the general partner in respect of 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 and except for the agreed upon adjustment discussed below, 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.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions will be

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\$75 million. Following the distribution in February 2009, the aggregate remaining incentive distribution reductions are \$31 million.

We paid \$106 million to the general partner in incentive distributions in 2008. On February 13, 2009, we paid a quarterly distribution of \$0.8925 per unit applicable to the fourth quarter of 2008, of which approximately \$30 million was paid to the general partner. See Item 13. "Certain Relationships and Related Transactions, and Director Independence 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. No such default has occurred. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Sources of Liquidity Credit Facilities and Long-Term Debt."

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2008, and we do not have any announced or existing plans to repurchase any of our common units.

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Item 6. Selected Financial Data

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2008, 2007, 2006, 2005 and 2004 and for the years then ended. 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,				
	2008	2007	2006	2005	2004
(in millions, except for per unit data)					
Statement of operations data:					
Total Revenues ⁽¹⁾	\$ 30,061	\$ 20,394	\$ 22,445	\$ 31,177	\$ 20,975
Income before cumulative effect of change in accounting principle ⁽²⁾	\$ 437	\$ 365	\$ 279	\$ 218	\$ 133
Net Income	\$ 437	\$ 365	\$ 285	\$ 218	\$ 130
Basic net income before cumulative effect of change in accounting principle ⁽²⁾	\$ 2.70	\$ 2.54	\$ 2.84	\$ 2.77	\$ 1.94
Basic net income after cumulative effect of change in accounting principle	\$ 2.70	\$ 2.54	\$ 2.91	\$ 2.77	\$ 1.89
Diluted net income before cumulative effect of change in accounting principle ⁽²⁾	\$ 2.67	\$ 2.52	\$ 2.81	\$ 2.72	\$ 1.94
Diluted net income after cumulative effect of change in accounting principle	\$ 2.67	\$ 2.52	\$ 2.88	\$ 2.72	\$ 1.89
Balance sheet data (at end of period):					
Total assets	\$ 10,032	\$ 9,906	\$ 8,715	\$ 4,120	\$ 3,160
Total long-term debt	3,259	2,624	2,626	952	949
Total debt	4,286	3,584	3,627	1,330	1,125
Partners' capital	3,552	3,424	2,977	1,331	1,070
Other data:					
Maintenance capital investments	\$ 81	\$ 50	\$ 28	\$ 14	\$ 11
Net cash provided by (used in) operating activities	\$ 857	796	(276)	24	104
Net cash used in investing activities	\$ (1,339)	(663)	(1,651)	(297)	(651)
Net cash provided by (used in) financing activities	\$ 464	(124)	1,927	271	555
Declared distributions per limited partner unit ⁽³⁾	\$ 3.50	\$ 3.28	\$ 2.87	\$ 2.58	\$ 2.30

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Volumes⁽⁴⁾⁽⁵⁾⁽⁶⁾					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,851	2,712	2,106	1,799	1,486
Trucking	97	105	101	84	64
Transportation Segment Total	2,948	2,817	2,207	1,883	1,550
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)					
	53	46	25	22	20
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet ("bcf"))					
	14	13	13	4	
LPG processing (average daily throughput in thousands of barrels)					
	17	18	12		
Facilities Segment Total (average monthly capacity in millions of barrels)					
	56	48	27	22	20
Marketing segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	658	685	650	610	589

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Refined products sales	26	11	N/A	N/A	N/A
LPG sales	103	90	70	56	48
Waterborne foreign crude oil imported	80	71	63	59	12
Marketing Segment Total	867	857	783	725	649

(1)

Includes gross presentation of buy/sell transactions for all periods prior to the second quarter of 2006. See Note 2 to our Consolidated Financial Statements for further discussion of buy/sell transactions.

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- (2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been \$224 million and \$136 million for 2005 and 2004, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been \$2.81 (\$2.76 diluted) and \$1.98 (\$1.98 diluted) for 2005 and 2004, respectively.
- (3) Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 5 to our Consolidated Financial Statements.
- (4) Volumes associated with acquisitions represent total volumes for the number of days or months we actually owned the assets divided by the number of days or months in the year.
- (5) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.
- (6) Facilities total is calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

Executive Summary

Internal Growth Projects and Acquisitions

Critical Accounting Policies and Estimates

Recent Accounting Pronouncements

Results of Operations

Outlook

Liquidity and Capital Resources

Off-Balance Sheet Arrangements

Executive Summary

Company Overview

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and LPG. In addition, through our 50% equity ownership in PAA/Vulcan, we are involved in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. See " Results of Operations Analysis of Operating Segments" for further discussion.

Overview of Operating Results, Capital Spending and Significant Activities

During 2008, our operations provided solid growth over 2007 and 2006 levels. The growth was driven primarily by our fee based activities included in our Transportation and Facilities segments. Much of the growth in these segments resulted from expanding our asset base through acquisitions and our ongoing internal growth projects. Our Marketing segment provided a positive contribution, but was down from 2007 and 2006. Lease gathering margins were stronger in 2008 than 2007. However, the 2007 results benefited from a contango crude oil market structure (which existed during the first half of the year), favorable crude oil differentials and favorable LPG margins. Key items impacting 2008 include:

Eight months' contributions to earnings from the Rainbow acquisition, which was completed in May 2008 for consideration of approximately \$687 million, as well as increased earnings resulting from prior acquisitions and expansion activities.

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A net loss of \$11 million resulting from inventory valuation adjustments partially offset by related net gains from derivative activities. This net loss includes a loss of \$145 million resulting from a write-down of inventory to its net realizable value. That loss is partially offset by gains of \$134 million on related derivatives. The inventory adjustment and the derivative gains were primarily the result of the significant decrease in crude oil and LPG prices that occurred during the second half of 2008.

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A net gain of \$7 million related to other derivative activities.

A gain of approximately \$29 million related to the settlement of the foreign currency and linefill hedges entered into in conjunction with the Rainbow acquisition.

Decreased earnings and increased expenses totaling an estimated \$15 million to \$20 million due to impacts of Hurricanes Gustav and Ike, both of which came through the Gulf Coast area during 2008.

A gain of approximately \$14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc.

Equity compensation plan expense of \$24 million for 2008 compared to \$49 million for the prior period. The decreased expense is primarily the result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007.

The issuance of \$600 million of senior notes for net proceeds of approximately \$597 million and the issuance of approximately 7 million limited partner units for net proceeds of approximately \$315 million.

Internal Growth Projects and Acquisitions

We completed a number of capital expansion projects and acquisitions in 2008, 2007 and 2006 that have impacted our results of operations and, combined with prudent financing, enabled us to enhance our liquidity, as discussed herein. The following table summarizes our capital expenditures for acquisitions, investments in unconsolidated entities, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2008	2007	2006
Acquisition capital	\$ 735	\$ 125	\$3,021
Investment in unconsolidated entities	37	9	44
Internal growth projects	491	525	332
Maintenance capital	81	50	28
	\$1,344	\$709	\$3,425

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Our 2008 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities. The following table summarizes our 2008 and 2007 projects (in millions):

Projects	2008	2007
Salt Lake City expansion ⁽¹⁾	\$ 154	\$ 72
Patoka tankage ⁽¹⁾	56	30
Paulsboro tankage ⁽¹⁾	30	
St. James Phase III	27	
Fort Laramie tank expansion	20	12
St. James, Louisiana storage facility	17	82
Rangeland tankage ⁽¹⁾	12	
Pier 400 ⁽²⁾	10	6
Kerrobert pumping project ⁽¹⁾	9	
Other projects ⁽³⁾	156	323
Total	\$491	\$525

(1) These projects will continue into 2009. See "Liquidity and Capital Resources - Uses of Liquidity - Capital Expenditures and Distributions Paid to Unitholders and General Partner - 2009 Capital Expansion Projects."

(2) This project requires approval of a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time. Does not include intangible expenditures of approximately \$5 million for emission reduction credits.

(3) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the effective date of each acquisition. Our ongoing acquisition and capital expansion activities are discussed further in "Liquidity and Capital Resources" and in Note 3 to our

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Consolidated Financial Statements. Information regarding acquisitions completed in 2008, 2007 and 2006 is set forth in the table below (in millions):

<u>Acquisitions</u>			
Acquisition	Effective Date	Acquisition Price	Operating Segment
Rainbow	05/01/2008	\$ 687	Transportation
San Pedro and other	11/13/2008	48	Facilities
2008 Total		\$ 735	
Bumstead LPG Storage Facility	07/24/2007	\$ 52	Facilities
Tirzah LPG Storage Facility	10/02/2007	54	Facilities
Other	Various	19	Transportation and Marketing
2007 Total		\$ 125	
Pacific	11/15/2006	\$ 2,456	Transportation, Facilities and Marketing
Andrews	04/18/2006	220	Transportation, Facilities and Marketing
SemCrude	05/01/2006	129	Marketing
BOA/CAM/HIPS	07/31/2006	130	Transportation
Products Pipeline	09/01/2006	66	Transportation
Other	Various	20	Transportation, Facilities and Marketing
2006 Total		\$ 3,021	

Pacific. On November 15, 2006 we completed our merger with Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included (i) the acquisition from LB Pacific of the general partner interest and incentive distribution rights of Pacific as well as approximately 5 million Pacific common units and approximately 5 million Pacific subordinated units for a total of \$700 million and (ii) the acquisition of the balance of Pacific's equity through a unit-for-unit exchange, resulting in the issuance of approximately 22 million Partnership units. The total value of the transaction was approximately \$2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership. See Note 3 to our Consolidated Financial Statements for discussion of the purchase price and related allocation, and discussion of the sources of funding.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States. These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting 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 estimates that we have identified are discussed below.

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Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2008, we estimate that approximately 1%, 1%, 6% and 8% of annual revenues, cost of sales, operating income and net income, respectively, were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact the respective line items by less than 1% on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives pursuant to Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities." as amended ("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. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Approximately 1% of total annual revenues are based on estimates derived from internal valuation models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, insurance claims, asset retirement obligations, taxes 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. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately \$8 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with SFAS No. 141 "Business Combination," with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values

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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, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

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. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer 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 and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable.

At December 31, 2008, we compared our market capitalization to our book equity, to determine if there was an indicator of impairment. Although, our market capitalization exceeded the book value of our equity at December 31, 2008, we updated our goodwill impairment test due to the ongoing deterioration of the credit markets and the overall economic conditions. We determined that the fair value was greater than book value for all three reporting units, and therefore goodwill was not considered impaired. We will continue to monitor the market to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. We did not have any goodwill impairments in 2008, 2007 or 2006. See Note 2 to our Consolidated Financial Statements for a discussion of goodwill.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity awards granted under our various Long Term Incentive Plans as well as outstanding Class B units of Plains AAP, L.P. (collectively, our "equity compensation plans"). Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

For equity awards granted under our various Long Term Incentive Plans, the total compensation expense recognized over the service period is determined by our unit price on the vesting date (or, in some cases, the average unit price for a range of dates preceding the vesting date) multiplied by the number of equity awards that are vesting, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in 25% increments upon PAA achieving annualized distribution levels of \$3.50, \$3.75, \$4.00 and \$4.50 (or, in some cases, within six months thereof). When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of \$11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Uncertainties involved in this estimate include the estimated date that PAA will achieve the annualized

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distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately \$24 million, \$49 million and \$43 million in 2008, 2007 and 2006, respectively, related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

whether there is an indication of impairment;

the grouping of assets;

the intention of "holding" versus "selling" an asset;

the forecast of undiscounted expected future cash flow over the asset's estimated useful life; and

if an impairment exists, the fair value of the asset or asset group.

During 2008, an impairment of approximately \$5 million was recognized for assets taken out of service. Impairments of approximately \$1 million and less than \$1 million were recognized during 2007 and 2006, respectively.

Recent Accounting Pronouncements

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our Consolidated Financial Statements.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 15 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership's other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. Facilities segment services are also obtained at rates generally consistent

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with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties. Intersegment rates are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

	For the Twelve Months Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	2008-2007		2007-2006	
				\$	%	\$	%
(In millions, except per unit data)							
Transportation segment profit	\$ 445	\$ 334	\$ 200	\$ 111	33 %	\$ 134	67 %
Facilities segment profit	153	110	35	43	39 %	75	214 %
Marketing segment profit	221	269	228	(48)	(18)%	41	18 %
Total segment profit	819	713	463	106	15 %	250	54 %
Depreciation and amortization	(211)	(180)	(100)	(31)	(17)%	(80)	(80)%
Interest expense	(196)	(162)	(86)	(34)	(21)%	(76)	(88)%
Interest income and other income (expense), net	33	10	2	23	230 %	8	400 %
Income tax expense	(8)	(16)		8	50 %	(16)	N/A
Income before cumulative effect of change in accounting principle	437	365	279	72	20 %	86	31 %
Cumulative effect of change in accounting principle			6			(6)	(100)%
Net income	\$ 437	\$ 365	\$ 285	\$ 72	20 %	\$ 80	28 %
Earnings per basic limited partner unit	\$ 2.70	\$ 2.54	\$ 2.91	\$ 0.16	6 %	\$(0.37)	(13)%
Earnings per diluted limited partner unit	\$ 2.67	\$ 2.52	\$ 2.88	\$ 0.15	6 %	\$(0.36)	(13)%
Basic weighted average units outstanding	120	113	81	7	6 %	32	40 %
Diluted weighted average units outstanding	121	114	82	7	6 %	32	39 %

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

Operating Results ⁽¹⁾ (in millions, except per barrel amounts)	Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	2008-2007		2007-2006	
				\$	%	\$	%
Revenues							
Tariff activities	\$ 800	\$ 654	\$ 438	\$ 146	22 %	\$ 216	49 %
Trucking	127	117	96	10	9 %	21	22 %
Total transportation revenues	927	771	534	156	20 %	237	44 %
Cost and Expenses							
Trucking costs	(88)	(80)	(71)	(8)	(10)%	(9)	(13)%
Field operating costs (excluding equity compensation expense)	(331)	(288)	(201)	(43)	(15)%	(87)	(43)%
Equity compensation income (expense) operation ⁽²⁾	(1)	(5)	(5)	4	80 %		
Segment G&A expenses (excluding equity compensation expense)	(56)	(50)	(43)	(6)	(12)%	(7)	(16)%
Equity compensation expense general and administrative ⁽²⁾	(11)	(19)	(16)	8	42 %	(3)	(19)%
Equity earnings in unconsolidated entities	5	5	2			3	150 %
Segment profit	\$ 445	\$ 334	\$ 200	\$ 111	33 %	\$ 134	67 %
Maintenance capital	\$ 54	\$ 34	\$ 20	\$ 20	59 %	\$ 14	70 %
Segment profit per barrel	\$ 0.41	\$ 0.34	\$ 0.26	\$ 0.07	21 %	\$ 0.08	31 %

Average Daily volumes (in thousands of barrels per day) ⁽³⁾	Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	2008-2007		2007-2006	
				Volumes	%	Volumes	%
Tariff activities							
All American	45	47	49	(2)	(4)%	(2)	(4)%
Basin	377	378	332	(1)		46	14 %
Capline	219	235	160	(16)	(7)%	75	47 %
Line 63/Line 2000	147	175	20	(28)	(16)%	155	775 %
Salt Lake City Area Systems	93	101	14	(8)	(8)%	87	621 %
West Texas/New Mexico Area Systems ⁽⁴⁾	372	369	403	3	1 %	(34)	(8)%
Manito	70	73	72	(3)	(4)%	1	1 %
Rainbow	129			129	N/A		N/A
Rangeland	58	63	24	(5)	(8)%	39	163 %
Refined products	109	109	24			85	354 %
Other	1,232	1,162	1,008	70	6 %	154	15 %
Tariff activities total	2,851	2,712	2,106	139	5 %	606	29 %
Trucking	97	105	101	(8)	(8)%	4	4 %
Transportation segment total	2,948	2,817	2,207	131	5 %	610	28 %

(1) Revenues and costs and expenses include intersegment amounts.

(2)

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Equity compensation expense related to our equity compensation plans.

- (3) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.
- (4) The volumes for the West Texas/New Mexico Area Systems previously included amounts for the Mesa system, which has been reclassified to "Other" for all periods presented.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit 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 field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

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Transportation segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for 2008 compared to 2007 and for 2007 compared to 2006. The significant variances in revenues and average daily volumes for 2008, 2007 and 2006 are discussed below:

Acquisitions and Expansion Projects Revenues and volumes for the year ended December 31, 2008 were impacted by the Rainbow acquisition, which occurred in May 2008. The Rainbow acquisition contributed approximately \$50 million of additional tariff revenues and additional volumes of approximately 129,000 barrels per day for the year ended December 31, 2008.

Revenues and volumes for the year ended December 31, 2007 were impacted by crude oil and refined products pipeline systems acquired or brought into service during 2007 and 2006 (primarily from the 2006 Pacific merger). Such acquisitions and systems brought into service contributed approximately \$164 million of additional tariff revenues and additional volumes of approximately 541,000 barrels per day for the year ended December 31, 2007.

Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Although there was a significant decline in the average price of crude oil during the fourth quarter of 2008, the average realized price per barrel related to our loss allowance revenues was higher during most of 2008 than it was in 2007. Additionally, volumes increased slightly for 2008 compared to 2007. As a result, loss allowance revenues increased by approximately \$31 million for the year ended December 31, 2008 compared to the year ended December 31, 2007.

In contrast, the average realized price per barrel related to our loss allowance revenues during 2007 was relatively comparable to the realized price per barrel for 2006; however, the volumes for 2007 increased significantly compared to the volumes for 2006. Therefore, loss allowance revenues increased by approximately \$24 million for the year ended December 31, 2007 compared to the year ended December 31, 2006.

Linefill Hedge Revenues for the year ended December 31, 2008 were impacted by a gain of approximately \$17 million related to the unwind of a linefill hedge entered into in conjunction with the Rainbow acquisition.

Rate Increases Rates increase on the majority of our domestic pipeline systems on July 1 of each year resulting in increased revenues year-over-year. Rates on our pipeline systems are increased through indexing by the FERC, by state and Canadian regulatory agencies and through market-based escalation.

Hurricane Impact Segment profit decreased by an estimated \$3 million to \$5 million due to impacts of Hurricanes Gustav and Ike, both of which came through the Gulf Coast area during the third quarter of 2008.

Foreign Exchange Revenues from our Canadian pipeline systems (other than Rainbow, as noted above) increased in 2007 compared to 2006 primarily due to the appreciation of Canadian currency. The average exchange rates for the years ended December 31, 2008, 2007 and 2006 were \$1.07:1, \$1.07:1 and \$1.13:1, respectively.

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Trucking Revenues for 2007 increased compared to 2006 due to trucking businesses that were acquired in both 2007 and 2006.

Basin and Capline Pipeline Systems Capline revenues and volumes were negatively impacted for 2008 compared to 2007 by the hurricanes as discussed above. There was an increase in revenues and volumes for 2007 compared to 2006 of approximately \$30 million and 122,000 barrels per day on the Basin and Capline pipeline systems. The increase on the Basin system was primarily a result of new connection points that were constructed and placed in service in 2007 as well as an increase in short-haul volumes. The increase in the Capline pipeline system revenues and volumes is primarily related to an existing shipper that increased its movements of crude oil in 2007.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) have increased in most categories for 2008 and 2007 due to various reasons including our continued growth through acquisitions, primarily related to the Rainbow acquisition, and expansion projects. The 2008 increased costs primarily relate to (i) utilities costs, which increased due to higher market prices, (ii) payroll and benefits and (iii) compliance with API 653 and pipeline integrity testing and maintenance requirements.

The most significant cost increases in 2007 compared to 2006 primarily related to (i) payroll and benefits, (ii) maintenance, (iii) utilities, (iv) property taxes and (v) compliance with API 653 and pipeline integrity testing and maintenance requirements.

General and Administrative Expenses. General and administrative expenses have increased in 2008 compared to 2007 in most categories including (i) payroll, (ii) contract labor and consulting fees and (iii) taxes due to various reasons including our continued growth through acquisitions and expansion projects. Our G&A expenses (excluding equity compensation charges as discussed below) were impacted in 2007 compared to 2006 primarily as a result of acquisitions and expansion projects.

Equity Compensation Charges. Equity compensation charges decreased approximately \$12 million in 2008 compared to 2007 primarily as a result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. Equity compensation charges increased approximately \$3 million in 2007 compared to 2006 primarily as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our transportation segment includes our equity earnings from our investments in Settoon Towing, Butte and Frontier. Barge transportation services are provided by Settoon Towing, in which we own a 50% equity interest. Butte and Frontier are pipeline systems in which we own an approximate 22% share in each system. The increase in 2007 compared to 2006 is due to the acquisitions of Frontier (in connection with the Pacific acquisition) and Settoon Towing in the fourth quarter of 2006.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in 2008 compared to 2007 is primarily due to increased investment applicable to in-line inspections and API 653 repairs in an effort to meet our 2009 compliance deadline (particularly on assets acquired from Pacific). The increase in maintenance capital for 2007 compared to 2006 was due to our ownership of an increased number of assets and pipeline systems resulting from our continued growth through acquisitions and expansion projects and from general inflationary pressures that have adversely impacted the energy industry.

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Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

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

Operating Results ⁽¹⁾ (in millions, except per barrel amounts)	For the Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	2008-2007		2007-2006	
	\$	\$	\$	\$	%	\$	%
Storage and terminalling revenues ⁽¹⁾	\$ 270	\$ 210	\$ 88	\$ 60	29 %	\$ 122	139 %
Field operating costs	(104)	(84)	(39)	(20)	(24)%	(45)	(115)%
Segment G&A expenses (excluding equity compensation expense)	(18)	(18)	(14)			(4)	(29)%
Equity compensation expense general and administrative ⁽²⁾	(4)	(8)	(6)	4	50 %	(2)	(33)%
Equity earnings in unconsolidated entities	9	10	6	(1)	(10)%	4	67 %
Segment profit	\$ 153	\$ 110	\$ 35	\$ 43	39 %	\$ 75	214 %
Maintenance capital	\$ 23	\$ 10	\$ 5	\$ 13	130 %	\$ 5	100 %
Segment profit per barrel	\$ 0.23	\$ 0.19	\$ 0.11	\$ 0.04	21 %	\$ 0.08	73 %

Volumes ⁽³⁾⁽⁴⁾⁽⁵⁾	For the Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	2008-2007		2007-2006	
	Volumes	Volumes	Volumes	Volumes	%	Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	53	46	25	7	15 %	21	84%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet ("bcf"))	14	13	13	1	8 %		
LPG processing (average throughput in thousands of barrels per day)	17	18	12	(1)	(6)%	6	50%
Facilities segment total (average monthly capacity in millions of barrels)	56	48	27	8	16 %	21	78%

(1) Revenues include intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the period.

(4) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a

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combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

(5)

Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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Facilities segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for 2008 compared to 2007 and for 2007 compared to 2006. The table below presents the significant variances in volumes and revenues (in millions) between 2008, 2007 and 2006:

	Crude Oil, Refined Products and LPG Storage ⁽¹⁾	Volumes		Revenues	
		Natural Gas Storage ⁽²⁾	LPG Processing ⁽³⁾		
2008 compared to 2007					
Increase due to:					
Acquisitions ⁽⁴⁾	2			\$	13
Expansions ⁽⁵⁾	6				37
Other	(1)	1		(1)	10
Total variance	7	1		(1)	\$ 60
2007 compared to 2006					
Increase due to:					
Acquisitions ⁽⁶⁾	16			6	\$ 98
Expansions ⁽⁷⁾	3				12
Other	2				12
Total variance	21			6	\$122

(1) Average monthly capacity (in millions of barrels).

(2) Average monthly capacity (in bcf).

(3) Barrels per day (in thousands).

(4) Revenues and volumes for 2008 compared to 2007 were impacted by the Bumstead and Tirzah acquisitions in 2007 in addition to the San Pedro acquisition that we closed during the fourth quarter of 2008. The Bumstead acquisition was completed in the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007.

(5) Expansion projects also resulted in an increase in revenues and volumes in 2008 compared to 2007. The Cushing, Martinez and St. James facilities all had significant expansion projects that were completed during 2008. Revenues for these facilities increased by a combined \$37 million. Aggregate volumes increased by approximately 6 million barrels for 2008 at these facilities.

(6) Revenues and volumes were primarily impacted in 2007 by acquisitions. The Pacific acquisition was completed in November 2006 and contributed additional revenues of approximately \$75 million and additional volumes of approximately 15 million barrels for 2007 compared to 2006. The acquisition of the Shafter processing facility in April 2006 resulted in additional processing revenues of approximately \$19 million and additional volumes of approximately 6,000 barrels per day for 2007 compared to 2006. The Bumstead and Tirzah acquisitions in July 2007 and October 2007, respectively, in the aggregate contributed additional revenues of approximately \$4 million and additional volumes of approximately 1 million barrels for 2007.

(7) Expansion projects also resulted in an increase in revenues and volumes in 2007 compared to 2006. The St. James and Kerrobert expansion projects were completed during 2007. Aggregate revenues and volumes for these facilities increased by approximately

\$12 million and approximately 3 million barrels, respectively, for 2007.

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Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) have increased in most categories for 2008 and 2007 due to various reasons including our continued growth through acquisitions, primarily related to the Tirzah and Bumstead acquisitions completed during 2007 and the additional tankage added at Cushing, St. James and Martinez in 2008 and 2007. The 2008 increased costs primarily relate to (i) payroll and benefits, (ii) utilities costs, which increased primarily due to increased usage as well as higher market prices, (iii) unplanned maintenance projects at several facilities and (iv) additional regulatory accruals.

The increase for 2007 compared to 2006 relates to the operating costs associated with the Shafter processing facility that was acquired in April 2006, the Pacific acquisition that was completed in November 2006, and the Bumstead and Tirzah acquisitions that were completed in July 2007 and October 2007, respectively, as well as the St. James expansion project that was ongoing throughout 2007.

General and Administrative Expenses. Our G&A expenses (excluding equity compensation charges as discussed below) were impacted in 2007 and 2006 primarily as a result of acquisitions and expansions.

Equity Compensation Charges. Equity compensation charges decreased by approximately \$4 million in 2008 compared to 2007 primarily as a result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. Equity compensation charges increased approximately \$2 million in 2007 compared to 2006 principally as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. Our investment in PAA/Vulcan contributed approximately \$4 million in additional earnings for 2007 compared to 2006, reflecting increased value for leased storage.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital for 2008 is primarily due to maintenance at various terminals, including the Martinez, Richmond, LA Basin and Cushing terminals. The increase in 2007 was primarily due to additional maintenance expenditures arising from the Pacific acquisition.

Marketing Segment

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our marketing segment volumes (which consist of (i) lease gathered crude oil purchase volumes, (ii) refined products volumes, (iii) LPG sales volumes and (iv) waterborne foreign crude oil imported) as well as the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the

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combination of our lease gathered business and our risk management activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and will vary from period to period.

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

Operating Results⁽¹⁾ (in millions, except per barrel amounts)	For the Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	\$	%	\$	%
Revenues ⁽²⁾⁽³⁾	\$ 29,350	\$ 19,858	\$ 22,061	\$ 9,492	48 %	\$ (2,203)	(10)%
Purchases and related costs ⁽⁴⁾⁽⁵⁾	(28,873)	(19,366)	(21,641)	(9,507)	(49)%	2,275	11 %
Field operating costs	(185)	(154)	(137)	(31)	(20)%	(17)	(12)%
Segment G&A expenses (excluding equity compensation charge)	(63)	(52)	(39)	(11)	(21)%	(13)	(33)%
Equity compensation charge general and administrative ⁽⁶⁾	(8)	(17)	(16)	9	53 %	(1)	(6)%
Segment profit ⁽³⁾	\$ 221	\$ 269	\$ 228	\$ (48)	(18)%	\$ 41	18 %
Net gains/(losses) related to inventory valuation adjustments and derivative activities ⁽³⁾	\$ (4)	\$ (27)	\$ (4)	\$ 23	85 %	\$ (23)	(575)%
Maintenance capital	\$ 4	\$ 6	\$ 3	\$ (2)	(33)%	\$ 3	100 %
Segment profit per barrel ⁽⁷⁾	\$ 0.70	\$ 0.86	\$ 0.80	\$ (0.16)	(19)%	\$ 0.06	7 %

Average Daily Volumes⁽⁸⁾ (in thousands of barrels per day)	For the Year Ended December 31,			Favorable (Unfavorable)			
	2008	2007	2006	Volumes	%	Volumes	%
Crude oil lease gathering purchases	658	685	650	(27)	(4)%	35	5%
Refined products sales	26	11	N/A	15	136 %	11	N/A
LPG sales	103	90	70	13	14 %	20	29%
Waterborne foreign crude oil imported	80	71	63	9	13 %	8	13%
Marketing segment total	867	857	783	10	1 %	74	9%

(1) Revenues and costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of \$4,762 million for the year ended December 31, 2006. This amount includes certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(3) Gains/(losses) from derivative activities net of inventory valuation adjustments.

(4) Includes purchases associated with buy/sell arrangements of \$4,795 million for the year ended December 31, 2006. This amount includes certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(5)

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Purchases and related costs include interest expense on hedged inventory purchases of approximately \$21 million, \$44 million and \$49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

- (6) Equity compensation expense related to our equity compensation plans.
- (7) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes and waterborne foreign crude volumes.
- (8) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Marketing segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Revenues and purchases and related costs. The variances between our revenues and purchases and related costs for 2008, 2007 and 2006 are discussed below.

Generally we consider the market to be favorable and are able to optimize and enhance the margins of our gathering and marketing activities when there is a high level of volatility in the

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market combined with favorable basis differentials and a steep contango or backwardated market structure. There was volatility in the outright price of crude oil during the last three years. The NYMEX benchmark price of crude oil ranged from approximately \$32 to \$147 per barrel, \$50 to \$99 per barrel and \$55 to \$78 per barrel for 2008, 2007 and 2006, respectively. In addition, there was volatility in the market structure in each of the last three years; 2008 and 2007 fluctuated between a contango market and a backwardated market but 2006 was in contango for the whole year. The monthly timespread of prices averaged approximately \$0.21 (contango) for 2008, versus \$0.32 (contango) for 2007 and an average contango spread of \$1.22 for 2006. A contango market is favorable to our commercial strategies that are associated with storage tankage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. In the fluctuating market structure for 2008 and 2007, we were able to optimize the margins of our gathering and marketing activities. Lease gathering margins were stronger in 2008 than 2007. However, the 2007 results benefited from a contango crude oil market structure (which existed during the first half of the year), favorable crude oil differentials and favorable LPG margins.

Results from our LPG operations were lower in 2008 as compared to the respective period of 2007. Our LPG operations operate on an April to March storage season and the timing of recognizing earnings over that season may vary from year to year based on the sales price of contracts presented for delivery and the average costing of inventory. Results for 2007 benefited from a strong first quarter that included profits from the end of the 2006 - 2007 storage season. Our LPG operations were also impacted by a foreign exchange unrealized loss, which we expect to recover through higher margins in future periods.

Results for 2008 include a net loss of \$11 million resulting from inventory valuation adjustments partially offset by related net gains from derivative activities. This net loss includes a loss of \$145 million resulting from a write-down of inventory to its net realizable value, which is partially offset by gains of \$134 million on related derivatives. The inventory adjustment and the derivative gains were primarily the result of the significant decrease in crude oil and LPG prices that occurred during the second half of 2008. Revenues for 2008 also include a net gain of \$7 million related to other derivative activities. Revenues for 2007 include losses related to derivative activities of approximately \$27 million. Revenues for 2006 include losses related to derivative activities of approximately \$4 million. Purchases and related costs for 2006 include an inventory valuation adjustment, which resulted in a loss of approximately \$6 million. See Note 6 to our Consolidated Financial Statements for a discussion of our derivative related activities.

Segment profit for the year ended December 31, 2008 was also negatively impacted by an estimated \$10 million to \$15 million due to reduced volumes and other impacts of Hurricanes Gustav and Ike.

Our revenues and purchases and related costs decreased for 2007 compared to 2006 due to the adoption in the second quarter of 2006 of Emerging Issues Task Force Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The adoption of EITF 04-13 in the second quarter of 2006 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income or liquidity.

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During 2007 and 2006, we purchased certain crude oil gathering assets and related contracts in South Louisiana, completed the acquisitions of Pacific and Andrews, and purchased a refined products supply and marketing business. These transactions primarily affected our transportation and facilities segment, but also included some marketing activities and opportunities. The integration into our business of these marketing activities precludes specific quantification of relative contribution, but we believe these acquisitions increased segment profit and revenues for our marketing segment.

Field Operating Costs. Field operating costs increased in 2008 compared to 2007, primarily due to increases in (i) transportation-related costs, including fuel, third-party trucking fees and drivers' salaries and (ii) the number of trucks and trailers under operating leases versus capital leases. Field operating costs increased in 2007 compared to 2006, primarily as a result of increases in (i) third-party trucking fees as a result of 2006 acquisitions, (ii) fuel costs resulting from higher market prices and (iii) maintenance costs as a result of 2006 acquisitions.

General and Administrative Expenses. General and administrative expenses increased for 2008 compared to 2007 primarily as a result of increases in payroll costs and consulting fees. General and administrative expenses increased for 2007 compared to 2006 primarily as a result of increased payroll and benefits (partly due to the retirement of an executive), as well as acquisitions and internal growth.

Equity Compensation Charges. Equity compensation charges decreased by approximately \$9 million in 2008 compared to 2007 primarily as a result of the decrease in unit price during 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. Equity compensation charges increased approximately \$1 million in 2007 compared to 2006 principally as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was \$211 million for the year ended December 31, 2008 compared to \$180 million and \$100 million for the years ended December 31, 2007 and 2006, respectively. The increases in 2008 and 2007 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Amortization of debt issue costs was \$4 million, \$3 million and \$3 million in 2008, 2007 and 2006, respectively.

Included in depreciation expense for the years ended December 31, 2008, 2007 and 2006 is a net gain of \$6 million, a net loss of approximately \$7 million and a net gain of approximately \$2 million, respectively, recognized upon disposition of certain inactive assets. Also included within depreciation expense for the year ended December 31, 2008 is an impairment of approximately \$5 million for assets taken out of service.

Interest Expense

Interest expense was \$196 million for the year ended December 31, 2008, compared to \$162 million and \$86 million for the years ended December 31, 2007 and 2006, respectively. Interest expense is primarily impacted by:

our average debt balances;

the level and maturity of fixed rate debt and interest rates associated therewith;

market interest rates and our interest rate hedging activities on floating rate debt; and

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interest capitalized on capital projects.

The following table summarizes selected components of our average debt balances (in millions):

	For the year ended December 31,					
	2008		2007		2006	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes ⁽¹⁾	\$3,028	87%	\$2,625	95%	\$1,336	92%
Borrowings under our revolving credit facilities ⁽²⁾	456	13%	150	5%	118	8%
Total	\$3,484		\$2,775		\$1,454	

(1) Weighted average face amount of senior notes, exclusive of discounts.

(2) Excludes borrowings under our senior secured hedged inventory facility and the short-term portion of our senior unsecured revolving credit facility, as the associated interest expense is recorded in crude oil, refined products and LPG purchases and related costs.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2008 and 2007 (in million, except for percentages):

	\$	Average LIBOR Rate	Weighted Average Interest Rate ⁽¹⁾
Interest expense for the year ended December 31, 2006	\$ 86	5.0%	6.1%
Impact of issuance and assumption of notes related to the Pacific acquisition ⁽²⁾	77		
Impact of issuance of senior notes ⁽³⁾	6		
Impact of increased borrowings under credit facilities ⁽⁴⁾	2		
Impact of increased capitalized interest	(8)		
Other	(1)		
Interest expense for the year ended December 31, 2007	\$ 162	5.2%	6.3%
Impact of issuance of senior notes ⁽⁵⁾	27		
Impact of increased borrowings under credit facilities ⁽⁴⁾	5		
Impact of increased capitalized interest	(3)		
Other	5		
Interest expense for the year ended December 31, 2008	\$ 196	2.7%	5.9%

(1) Excludes commitment and other fees.

(2) In October 2006, we issued \$1.0 billion senior notes to partly finance the Pacific acquisition in November 2006. In connection with the Pacific acquisition, we also assumed \$400 million senior notes from Pacific.

(3) In May 2006, we issued \$250 million of senior notes.

(4)

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The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in LIBOR rates.

(5) The \$600 million senior notes were issued in April 2008 in connection with the Rainbow acquisition.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing segment profit as we consider interest on these

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borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately \$21 million, \$44 million and \$49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Interest Income and Other, Net

Interest income and other, net increased by approximately \$23 million for the year ended December 31, 2008, compared to the year ended December 31, 2007 primarily due to (i) a gain of \$14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc. and (ii) a gain of \$11 million on the foreign currency hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition.

Interest income and other, net increased by approximately \$8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, primarily due to (i) the recognition of a gain of approximately \$4 million upon the sale of a portion of our stock ownership in NYMEX Holdings, Inc. and (ii) the change in fair value of our interest rate swaps.

Income Tax Expense

Excluding the \$10 million impact of the initial adoption of the revised Canadian tax laws in 2007, our income tax expense increased by \$2 million in 2008 compared to 2007 primarily due to the Rainbow acquisition. Income tax expense was \$16 million for the year ended December 31, 2007 primarily due to revised rules on Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. There was no income tax in 2006. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

During 2008, we grew our business by expanding our asset base through approximately \$735 million of acquisitions and \$491 million of internal growth projects. In 2009, we intend to spend approximately \$295 million on internal growth projects. Several of the larger storage tank projects for 2008 and 2009, such as the construction or expansion of the Patoka, St. James and Cushing terminals, are well positioned to benefit from the importation of waterborne foreign crude oil into the Gulf Coast as well as the importation of Canadian crude oil and the associated diluent requirements to facilitate its movement. We also believe there are opportunities for us to grow our LPG business and the natural gas storage business of PAA/Vulcan. In late 2008, PAA/Vulcan's management team was further strengthened and a major gas storage project was placed into partial commercial operation. The management team of PAA/Vulcan has been charged with developing the company into a solid, stand alone business through organic growth, acquisitions and greenfield development projects.

We intend to continue to develop our inventory of projects for implementation beyond 2009 throughout all of our product and growth platforms, and to