PLAINS ALL AMERICAN PIPELINE LP Form 10-K February 28, 2012 Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

o 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

76-0582150

(State or other jurisdiction of incorporation or organization)

(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 Common Units Name of Each Exchange on Which Registered 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 x No o

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 o No x

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

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 x

Accelerated Filer o

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

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

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 \$8.4 billion on June 30, 2011, based on a closing price of \$64.00 per Common Unit as reported on the New York Stock Exchange on such date.

As of February 22, 2012, there were 155,568,749 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2011 ANNUAL REPORT

Table of Contents

		Page
	<u>PART I</u>	3
Items 1 and 2.	Business and Properties	3
Item 1A.	Risk Factors	38
Item 1B.	Unresolved Staff Comments	53
Item 3.	Legal Proceedings	53
Item 4.	Mine Safety Disclosures	55
	PART II	56
Item 5.	Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities	56
Item 6.	Selected Financial Data	58
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	59
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	83
Item 8.	Financial Statements and Supplementary Data	84
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	84
Item 9A.	Controls and Procedures	85
Item 9B.	Other Information	85
	PART III	86
Item 10.	Directors and Executive Officers of Our General Partner and Corporate Governance	86
Item 11.	Executive Compensation	96
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	115
Item 13.	Certain Relationships and Related Transactions, and Director Independence	118
Item 14.	Principal Accountant Fees and Services	122
	PART IV	123
Item 15.	Exhibits and Financial Statement Schedules	123

1

4

Table of Contents

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 incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and						
regarding our business strategy, plans and objectives 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 to be						
reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking						
statements. The most important of these factors include, but are not limited to:						

•	failure to consummate and integrate the BP NGL Acquisition;
•	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 do business;
•	the effectiveness of our risk management activities;
•	unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
•	environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
• pipeline sy	abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our estems;

shortages or cost increases of supplies, materials or labor;

	the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and ors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from l and gas reserves or failure to develop additional oil and gas reserves;
• refined pro	fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, oducts 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;
• requiremen	our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital nts and the repayment or refinancing of indebtedness;
• business th	the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of nat are distinct and separate from our historical operations;
• interpretati	the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related ions;
•	the effects of competition;
•	interruptions in service on third-party pipelines;
•	increased costs or lack of availability of insurance;
•	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;
	2

Tabl	e of	Contents
1 au	U OI	Contonts

• weather interference with business operations or project construction;
• risks related to the development and operation of natural gas storage facilities;
• factors affecting demand for natural gas and natural gas storage services and rates;
• general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
• other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.
Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Item 1A. Risk Factors. Except as required by applicable securities laws, we do not intend to update these forward-looking statement and information.
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 and unless the context indicates otherwise, the terms Partnership, Plain PAA, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries.

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids (NGL). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquefied petroleum gas (LPG). As used in this Form 10-K, the terms NGL and LPG are sometimes used interchangeably depending on the context. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also own and operate natural gas storage facilities. Our business

activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

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 are owned by 18 holders and their affiliates. The five largest of these holders and their affiliates own an aggregate interest of approximately 95%. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

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.).

Table	αf	Contents	

The chart below depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries as of February 22, 2012.

⁽¹⁾ Based on Form 4 filings for executive officers and directors, 13D filings for Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 9.5 million limited partner units, representing approximately 6% 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.

(3)	The Partnership holds direct and indirect ownership interests in consolidated operating subsidiaries including, but not
limited to, Plains Pipel	ine, L.P., Plains Marketing, L.P., Plains LPG Services, L.P., Pacific Energy Group LLC and Plains Midstream
Canada ULC (PMC).

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including Settoon Towing, LLC (Settoon Towing), White Cliffs Pipeline, LLC (White Cliffs), Butte Pipe Line Company (Butte) and Frontier Pipeline Company (Frontier).

4

<u>Table of Contents</u>
Business Strategy
Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage, processing, fractionation and supply and logistics 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, NGL and natural gas in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling, storage, processing and fractionation assets with our extensive supply, logistics 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;
• using our transportation, terminalling, storage, processing and fractionation assets in conjunction with our supply and logistics activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin;
• developing and implementing internal growth projects that (i) address evolving crude oil, refined products, natural gas and NGL needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;
• selectively pursuing strategic and accretive acquisitions that complement our existing asset base and distribution capabilities; and
• capitalizing on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services through our ownership interest in PNG.
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. In that regard, we intend to maintain a credit profile that we believe is consistent with our 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 45% to 50%;
- a long-term debt-to-adjusted EBITDA multiple averaging between 3.5x and 4.0x (Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation plan charges, gains and losses from derivative activities and other selected items that impact comparability. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Non-GAAP Financial Measures for a discussion of our selected items that impact comparability and our non-GAAP measures.);
- an average total debt-to-total capitalization ratio of approximately 60%; and
- an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

5

Table of Contents

The first two of these four metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with our supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, NGL and natural gas. The crude oil, NGL and natural gas purchased in these transactions are hedged. We do not consider the working capital borrowings associated with these activities 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 to fund New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund 55% 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.

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 supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins. We believe the variety of activities executed within our supply and logistics segment in combination with our risk management strategies provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, we are able to realize incremental margins 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 fourteen years, we have completed and integrated over 70 acquisitions with an aggregate purchase price of approximately \$8.2 billion. We have also implemented internal expansion capital projects totaling approximately \$3.0 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2011, we had over \$3.6 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 27 years industry experience, and an average of 16 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.

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, NGL 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.

Table of Contents

The following table summarizes acquisitions greater than \$200 million that we have completed over the past five years (in millions). See Note 3 to our Consolidated Financial Statements for a full discussion regarding our acquisition activities.

Acquisition	Date	Description	Approximate Purchase Price(1))
Western Refining, Inc. (Western)	Dec-2011	Multi-product storage facility in Virginia and Crude oil pipeline in southeastern New Mexico	\$	220(2)
Velocity South Texas Gathering, LLC (Velocity)	Nov-2011	Crude oil and condensate gathering and transportation assets in South Texas (Gardendale Gathering System)	\$	349
SG Resources Mississippi, LLC (SG Resources)	Feb-2011	Southern Pines Energy Center (Southern Pines) natural gas storage facility	\$	765(3)
Nexen Holdings U.S.A. Inc. (Nexen)	Dec-2010	Crude oil gathering business and transportation assets in North Dakota and Montana	\$	229(4)
PAA Natural Gas Storage, LLC (PNGS)	Sep-2009	Remaining 50% interest in PNGS	\$	215(5)
Rainbow Pipe Line Company, Ltd. (Rainbow)	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	\$	687(6)

⁽¹⁾ As applicable, the approximate purchase price includes total cash paid and debt assumed, including amounts for working capital and inventory.

- (2) Includes two transactions with Western.
- (3) Acquisition made by our subsidiary, PNG. Approximate purchase price of \$750 million, net of cash and other working capital acquired.
- (4) Approximate purchase price of \$170 million, net of cash, inventory and other working capital acquired.
- (5) In connection with the PNGS acquisition we consolidated and subsequently refinanced approximately \$450 million of previously non-recourse joint venture debt.
- (6) Approximate purchase price of \$544 million, net of linefill acquired.

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. 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 our existing 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.

We typically do not announce a transaction until after we have executed a definitive acquisition agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of an acquisition until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive acquisition agreement will be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition efforts will be successful. 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 or if we make acquisitions that fail to perform as anticipated, our future growth may be limited and Our acquisition strategy involves risks that may adversely affect our business.

Pending BP NGL Acquisition. On December 1, 2011, we entered into a definitive agreement to acquire all outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (BP North America). Total consideration for the acquisition, which will be based on an October 1, 2011 effective date, is approximately \$1.67 billion, subject to working capital and other adjustments. A cash deposit of \$50 million was paid upon signing, and the balance, plus 2% interest from October 1, 2011, is payable in cash upon closing. Subject to Canadian and U.S. regulatory approvals and other customary closing conditions, the acquisition is expected to close in the second quarter of 2012.

Upon completion of this acquisition, we will become the indirect owner of all of BP North America s Canadian-based NGL business and certain of BP North America s NGL assets located in the upper-Midwest United States (collectively the BP NGL Assets). The BP NGL Assets to be acquired include varying ownership interests and contractual rights relating to approximately 2,600 miles of NGL pipelines; approximately 20 million barrels of NGL storage capacity; seven fractionation plants with an aggregate net capacity of approximately 232,000 barrels per day; four straddle plants and two field gas processing plants with an aggregate net capacity of approximately six Bcf per day; and long-term and seasonal NGL inventories of approximately 10 million barrels as of October 1, 2011. Certain of these pipelines and storage assets are currently inactive. The acquired business also includes various third-party supply contracts at other field gas processing plants and a supply contract relating to a third-party owned straddle plant with throughput capacity of 2.5 Bcf per day, shipping arrangements on third-party NGL pipelines and long-term leases on 720 rail cars used to move product among various locations. Collectively, these assets and activities provide access to approximately 140,000 to 150,000 barrels per day of NGL supply that are transported through an integrated network to fractionation facilities and markets in Western and Eastern

Table of Contents

Canada and in the U.S. Subject to closing the transaction, we have also entered into an Integrated Supply and Trading Agreement, pursuant to which an affiliate of BP North America will, for a period of two years following the closing of the acquisition, continue to provide sourcing services for gas supply to feed certain of the straddle plants to be acquired as a result of the acquisition.

Global Petroleum Market Overview

The United States comprises less than 4% of the world s population, generates approximately 12% of the world s petroleum production, and consumes approximately 22% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil and NGL) and is derived from the Energy Information Administration s (EIA) Annual Energy Outlook 2012 Early Release (see EIA website at www.eia.doe.gov):

	Projected				
	2011 (1)	2012	2013	2015	2020
		(In milli	ons of barrels per d	lay)	
Supply					
OECD (2)					
U.S.	10.3	10.4	10.5	11.0	12.0
Other	11.8	12.0	12.0	11.6	11.2
Total OECD	22.1	22.4	22.5	22.6	23.2
Organization of the Petroleum Exporting Countries	34.4	34.9	35.8	36.4	38.5
Other	31.6	32.2	31.8	32.9	35.1
Total World Production	88.1	89.5	90.1	91.9	96.8

	Projected				
	2011 (1)	2012	2013	2015	2020
		(In millio	ons of barrels per d	lay)	
<u>Demand</u>					
OECD					
U.S.	19.3	19.1	18.9	19.3	19.4
Other	26.6	26.8	27.0	26.8	27.6
Total OECD	45.9	45.9	45.9	46.1	47.0
Other	42.2	43.6	44.2	45.8	49.8
Total World Consumption	88.1	89.5	90.1	91.9	96.8
U.S. Production as % of World Production	12%	12%	12%	12%	12%
U.S. Consumption as % of World Consumption	22%	21%	21%	21%	20%
Net U.S. (Consumption)	(9.0)	(8.7)	(8.4)	(8.3)	(7.4)
Net U.S. (Consumption)	(9.0)	(8.7)	(8.4)	(8.3)	(7.4)

⁽¹⁾ The 2011 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. The challenging global economic climate of the last several years has resulted in continued uncertainty in the petroleum market. To the extent that an event causes weaker world economic growth, energy demand would likely decline and could result in lower energy prices, depending on the production responses of producers.

Crude Oil Market Overview

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. For example, specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, along with other characteristics, collectively result in varying economic attributes. 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.

Table of Contents

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. The nature and extent of these imbalances change from time to time as a result of a variety of factors, including regional production declines and/or increases; refinery expansions, modifications and shut-downs; available transportation and storage capacity and government mandates and related regulatory factors.

For the 20-year time period beginning in 1985 through 2004, U.S. refinery demand for crude oil increased approximately 29% from approximately 12.0 million barrels per day to approximately 15.5 million barrels per day. U.S. refinery demand for crude oil remained effectively flat from 2005 through 2007 at around 15.5 million barrels per day. Largely as a result of a major economic slowdown and recession, from 2008 to 2011 total U.S. petroleum consumption declined and refinery demand decreased, averaging approximately 14.8 million barrels per day for the 12 months ended October 2011. Of this amount, approximately 5.7 million barrels per day were produced domestically. Accordingly, for the 12 months ended October 2011, approximately 9.1 million barrels per day of the crude oil used by U.S. refineries were imported. This level of crude oil imports represents a meaningful change in a multi-year trend where foreign imports of crude oil tripled over a 23-year period, from approximately 3.2 million barrels per day in 1985 to approximately 10.1 million barrels per day from 2005-2007. Reduced domestic demand for petroleum products from end users and competitive challenges faced by certain U.S. refineries with limited access to domestic feedstocks as well as increased use of ethanol for blending in gasoline have been major factors contributing to the drop in refinery demand for crude oil, partially offset by rising refined products exports. Since 2000, ethanol production has grown from approximately 100,000 barrels per day to approximately 900,000 barrels per day for the 12 months ended October 2011. Growth in ethanol and other renewable fuel production is expected to continue primarily due to government mandates on production. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production and increased supply from other liquid products, including ethanol and biodiesel.

The table below shows the overall domestic petroleum consumption projected out to 2020 and is derived from recent information published by the EIA (see EIA website at www.eia.doe.gov). The amounts in the 2011 column are based on the twelve months from November 2010 to October 2011. We believe these trends will be subject to significant variation from time to time due to a number of factors, including the level of domestic production volumes and infrastructure limitations which impact pricing and geopolitical developments. Based on market and industry conditions throughout 2011 and conditions in early 2012, it appears domestic crude oil and NGL production levels and refined products exports could exceed the EIA s forecast over the next several years.

	Actual		Projecto	ed	
	2011	2012	2013	2015	2020
		(in milli	ons of barrels per da	y)	
Supply					
Domestic Crude Oil Production	5.7	5.9	6.0	6.3	6.7
Net Imports - Crude Oil	9.1	8.9	8.6	8.5	7.4
Crude Oil Input to Domestic Refineries	14.8	14.8	14.6	14.8	14.1
Product Imports	2.3	2.4	2.1	2.1	2.0
Product Exports	(2.6)	(2.4)	(2.3)	(2.3)	(2.0)
Net Product Imports	(0.3)		(0.2)	(0.2)	

Supply from Renewable Sources	0.8	1.0	1.0	1.1	1.3
Other - (NGL Production, Refinery Processing Gain)	3.8	3.3	3.5	3.6	4.0
Total Domestic Petroleum Consumption	19.1	19.1	18.9	19.3	19.4

As illustrated in the table above, imports of foreign crude oil and other petroleum products play a major role in achieving a balanced U.S. market on an aggregate basis. However, because of the substantial number of different grades and varieties of crude oil and their distinguishing physical and economic properties and the distinct configuration of each refinery s process units, significant logistics infrastructure and services are required to balance the U.S. market on a region by region basis.

By way of illustration, 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 each PADD for the twelve months ended October 2011 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov):

	Regional	Refinery	Supply
Petroleum Administration Defense District (in millions of barrels per day)	Supply	Demand	Shortfall
PADD I (East Coast)		1.1	(1.1)
PADD II (Midwest)	0.8	3.3	(2.5)
PADD III (South)	3.3	7.5	(4.2)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.2	2.4	(1.2)
Total U.S.	5.7	14.8	(9.1)

Table of Contents

As a result of advances in horizontal drilling and fracturing technology over the last several years and their application to various large scale resource plays, certain historical trends are being influenced. For example, PADD II production increased beginning in 2005 and as of early 2012 is estimated to be over 800,000 barrels per day, nearly double 2004 s level. This increase is being driven mainly by increased production from the Bakken oil formation in North Dakota using advanced horizontal drilling and fracturing technology.

More recently, other parts of the U.S. have experienced increased production volumes from mature producing areas such as the Rockies, the Permian Basin in West Texas, as well as less developed areas such as the Eagle Ford Shale in South Texas. Actual and anticipated production increases in multiple areas combined with actual and expected increased imports from Canada has strained or is expected to strain existing transportation and terminalling infrastructure in multiple areas. These developments are also resulting in changes to historical trends with respect to crude oil movements between regions of the U.S. For example, the quantity of crude oil transported from the Gulf Coast area into PADD II has declined, but the overall change in crude oil flows has resulted in an increased demand for storage and terminalling services at Cushing, Oklahoma and Patoka, Illinois.

The quality of the increasing crude oil volumes, which are generally lighter (higher gravity) and sweeter (lower sulfur content) than previous production, is exacerbating the demands placed on existing infrastructure. Notably, this change in crude oil quality is in stark contrast to the sizeable, multi-year investments made by a number of U.S. refining companies in order to expand their capabilities to process heavier, sourer grades of crude oil, which caused differentials between crude oil grades and qualities to change relative to historical levels and become much more dynamic and volatile. The combination of (i) a significant increase in North American production volumes, (ii) a change in crude oil qualities and related differentials and (iii) a high utilization of existing pipeline and terminal infrastructure have stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, convert certain pipeline assets to alternative service or reverse flows and expand the use of trucks, rail and barges for the movement of crude oil.

Overall, volatility in various aspects of the crude oil market including absolute price, market structure and grade and location differentials has increased over time and we expect this volatility to persist. Some factors that we believe are causing and will continue to cause volatility in the market include:

- the multi-year narrowing of the gap between supply and demand in North America;
- fluctuations in international supply and demand related to the economic environment, geopolitical events and armed conflicts;
- regional supply and demand imbalances and changes in refinery capacity and specific capabilities;
- significant fluctuations in absolute price as well as grade and location differentials;
- political instability in critical producing nations; and

policy decisions made by various governments around the world attempting to navigate energy challenges.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business.
Refined Products Market Overview
After transport to a refinery, the crude oil is processed into different petroleum products. These refined products fall into three major categories: transportation 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 transportation fuels, particularly motor gasoline.
The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced. 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, conservation, fuel efficiency mandates and, to a lesser extent, weather conditions. According to the EIA, petroleum consumption in the United States rose from approximately 15.7 million barrels per day in 1985 to an average of approximately 20.7 million barrels during the four-year period ending with 2007. From 2008 through the 12 months ended October 2011, petroleum consumption averaged approximately 19.1 million barrels per day, an approximate 8% decrease from peak levels, largely due to the economic weakness. Given this decreased demand for refined products, the increased use of ethanol and other renewable fuels and the resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely shut-down. The EIA is currently forecasting growth in overall refined product demand to increase marginally over the next decade.

10

Table of Contents

The level of future domestic demand generally will be influenced by the slope of the economic recovery as well as the absolute prices of the products. Counteracting the impact of decreased domestic refined product demand on many U.S. refineries has been the combination of a significant decrease in refined product imports and a significant increase in refined product exports. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 2.3 million barrels per day for the twelve months ended October 2011. Conversely, refined product exports increased from approximately 1.1 million barrels in 2005 to 2.6 million barrels for the twelve months ended October 2011. We believe that potential demand growth will be met primarily by the increase in mandated alternative fuels and increased

utilization of existing refining capacity, the combination of which we believe will generate demand for midstream infrastructure, including pipelines and terminals. We believe that demand for refined products pipeline and terminalling infrastructure will also be driven by the following factors:
• multiple specifications of existing products (also referred to as boutique gasoline blends);
• continued specification changes to existing products, such as lower sulfur limits; and
• increased acceptance and mandates of biofuels and other related renewable fuels.
The complexity and volatility of the refined products market creates opportunities to solve the logistical challenges inherent in the business.
NGL Market Overview
NGLs primarily include ethane, propane, normal butane, iso-butane, and natural gasoline, and are derived from natural gas production and processing activities as well as crude oil refining processes. LPG primarily includes propane and butane which liquefy at moderate pressures thus making it easier to transport and store such products. As discussed above, the terms NGL and LPG are sometimes used interchangeably

depending upon the context.

NGL Demand. Individual NGL products have varying uses. Described below are the five basic NGL components and their typical uses:

- Ethane. Ethane accounts for the largest portion of the NGL barrel and substantially all of the extracted ethane is used as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. When ethane recovery from a wet natural gas stream is uneconomic, ethane is also left in the gas stream to be burned as fuel, subject to pipeline specifications.
- Propane. Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and also as petrochemical feedstock for the production of ethylene and propylene.

	Normal butane. Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with d feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive
•	Iso-butane. Iso-butane is principally used by refiners to produce alkylates to enhance the octane content of motor gasoline
•	Natural Gasoline. Natural gasoline is principally used as a motor gasoline blend stock or as a petrochemical feedstock.
Certain NG Canada.	Ls, primarily natural gasoline and butane, are also used as diluents in the transportation of heavy crude oil (bitumen), particularly in
the dry gas	y. The bulk (approximately 71%) of the U.S. NGL supply comes from gas processing plants, which separate a mixture of NGL from (primarily methane). The NGL mix (also referred to as Y Grade) is then either fractionated at the processing site into the individual s (known as purity products), which may be transported, stored and sold to end use markets or transported as a Y-Grade to a regional n facility.
Smaller gas	y of gas processing plants in the U.S. are located along the Gulf Coast, in the West Texas/Oklahoma area and in the Rockies region. processing regions are located in Michigan and Illinois as well as the Marcellus region (which is expanding rapidly) and Southern In Canada, the vast majority of the processing capacity is located in Alberta, with a much smaller (but increasing) amount in British
	11

Table of Contents

NGL products from refineries represent approximately 20% of U.S. supply and are by-products of the refinery conversion processes. Consequently, they have generally already been separated into individual components and do not require further fractionation. NGL products from refineries are principally propane, with lesser amounts of butane, refinery naphthas (products similar to natural gasoline) and ethane. Due to refinery maintenance schedules and butane blending considerations, refinery production of propane and butane varies on a seasonal basis.

NGLs are also imported into certain regions of the U.S. from Canada and other parts of the world (approximately 9% of total supply). NGLs (primarily propane) are also exported from certain regions of the United States.

NGL Transportation and Trading Hubs. NGLs, whether as a mixture or as purity products, are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of product are to be delivered.

The major NGL infrastructure and trading hubs in North America are located at Mont Belvieu, Texas; Conway, Kansas; Edmonton, Alberta; and Sarnia, Ontario. Each of these hubs contains a critical mass of infrastructure, including fractionators, storage, pipelines and access to end markets, particularly Mont Belvieu. Pricing at these hubs is relatively transparent and is tracked in several industry publications. In addition, there are several other hubs, including Empress and Fort Saskatchewan, Alberta and Hobbs, New Mexico. The West Virginia/Western Pennsylvania area is also rapidly developing as a meaningful NGL infrastructure hub.

NGL Storage. NGLs must be stored under pressure to maintain their liquid state. The lighter the product (e.g., ethane), the greater the pressure that must be maintained. Large volumes of NGLs are stored in underground caverns constructed in salt or granite. Product is also stored in above ground tanks. Natural gasoline can be stored at relatively low pressures in tankage similar to that used to store motor gasoline. Propane and butane are stored at much higher pressures in steel spheres, cylinders, bullets or other configurations. Ethane is stored at very high pressures, typically in salt caverns. Storage is especially important for NGLs as supply and demand can vary materially on a seasonal basis.

NGL Market Outlook. NGL supplies from gas processing plants are increasing rapidly due to the increased drilling activity in unconventional resource plays, where producers are targeting—liquids rich—areas to capitalize on high NGL product prices (which historically have been correlated with crude oil prices). Numerous industry and financial analysts project NGL supply volumes will continue to grow over the next several years with some analysts projecting U.S. supply volumes to increase from current levels by as much as 40% by 2016. A significant amount of this volume is expected to come from recently discovered, unconventional resource plays which do not have the NGL infrastructure to process the wet natural gas or transport, fractionate, and store the NGL products. Nor are these new supply areas near historical markets for the NGL purity products. As a result of these dynamics, substantial incremental infrastructure is likely to be developed throughout the NGL value chain over the next several years. A portion of the increased supply of product will likely be absorbed by the domestic petrochemical sector as low cost feed stocks. In addition, growing production of Canadian heavy crude oil is likely to create demand for additional diluents, primarily natural gasoline and butane. The remaining product not absorbed domestically will likely drive continued growth in the LPG export market. The NGL market is, among other things, expected to be driven by:

Table of Contents

•	the absolute prices of NGL products and their prices relative to natural gas;
•	drilling activity and wet natural gas production in developing liquids-rich production areas;
•	production growth/decline rates of wet natural gas in established supply areas;
•	available processing, fractionation, storage and transportation capacity;
•	infrastructure development costs and timing as well as development risk sharing;
•	the cost of acquiring processing rights (e.g. extraction premiums) from producers to process their gas;
•	petro-chemical demand;
•	diluent requirements for Canadian heavy oil;
•	international demand for LPG products;
•	regulatory changes in gasoline specifications affecting demand for butane;
•	refinery shut downs;
•	alternating needs of refineries to store and blend LPG;
•	seasonal shifts in weather; and

• inefficiencies caused by regional supply and demand imbalances.
As a result of these and other factors, the NGL market is complex and volatile, which along with expected market growth creates opportunities to solve the logistical inefficiencies inherent in the business.
Natural Gas Storage Market Overview
North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation. Natural gas storage (and to a lesser extent imported natural gas from Canada) serves as the shock absorber that balances the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods.
The market for natural gas storage services in the United States is driven by:
• the long-term supply and demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis;
• natural gas demand from seasonal or weather-sensitive end-users such as gas-fired power generators and residential and commercial consumers;
• any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations;
• operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials; and
• the extent to which there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area.
13

Table of Contents

During the period from 2001 through 2011, domestic natural gas consumption has grown, albeit unevenly, primarily as a result of growth in the seasonal and weather-sensitive electric power generation and commercial sectors. This growth was offset by declines in the residential and industrial sectors. For a number of years during the same period, domestic natural gas production was relatively flat and failed to keep pace with domestic consumption. Over the past several years, however, domestic natural gas production has been growing rapidly, primarily due to significant increases in production from developing shale resource plays.

The seasonality of natural gas demand has remained strong during the last decade, with consumption during the peak winter months averaging approximately 40% more than consumption during the summer months, per EIA data. This strong seasonal trend has produced seasonal spreads (the price difference between the summer and winter season) that have generally moved within a range of approximately \$0.37-\$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, in 2011 the seasonal spreads (Oct-Jan) traded in a range of approximately \$0.37-\$0.62. While there are a variety of factors that have contributed to these softer market conditions, we believe the key drivers are (i) relatively flat natural gas consumption over the last year (and projected flat consumption for the next several years), (ii) increased natural gas supplies due to production from shale resources, (iii) net increases in storage capacity and (iv) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years. We believe that certain of the supply and demand factors are cyclical and self correcting over time, and that the long term outlook for storage utilization and demand is positive.

Description of Segments and Associated Assets

Our business activities are conducted through three segments Transportation, Facilities and Supply and Logistics. We have an extensive network of transportation, terminalling and storage facilities at major market hubs and in key oil producing basins, as well as 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 Settoon Towing, White Cliffs, Butte and Frontier, in which we own noncontrolling interests.

Table of Contents

As of December 31, 2011, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 16,000 miles of active crude oil and refined products pipelines and gathering systems;
- 23 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 67 trucks and 382 trailers; and
- 82 transport and storage barges and 44 transport tugs through our interest in Settoon Towing.

The following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2011, grouped by geographic location:

		2011 Average Net Barrels
Region / Pipeline and Gathering Systems (1)	System Miles	per Day (2) (in thousands)
Southwest US		
Basin	521	440
Permian Basin Area Systems	2,969	404
Other	162	127
Southwest US Subtotal	3,652	971
Western US		
All American	138	35
Line 63/Line 2000	362	114
Other	150	82
Western US Subtotal	650	231
<u>US Rocky Mountain</u>		
Salt Lake City Area Systems	731	137
Other	3,972	348
US Rocky Mountain Subtotal	4,703	485
US Gulf Coast		
Capline(3)	631	160
Other	1,089	326
US Gulf Coast Subtotal	1,720	486
<u>Central US</u>		
Mid-Continent Area Systems	2,023	213
Other	376	132
Central US Subtotal	2,399	345
Domestic Total	13,124	2,518

<u>Canada</u>		
Rangeland	1,221	59
Rainbow	594	135
Manito	555	66
Other	612	164
Canada Total	2,982	424
Grand Total	16,106	2,942

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

⁽²⁾ Represents average volume for the entire year.

⁽³⁾ Non-operated pipeline.

Table	e of	Contents

Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and are the operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil 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 system 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 440,000 barrels per day (attributable to our interest) during 2011.

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 6 million barrels of tankage located along the system. The Basin system is subject to tariff rates regulated by the FERC.

Permian Basin Area Systems. We operate wholly owned systems of approximately 3,000 miles that aggregate receipts from wellhead gathering lines and bulk truck injection locations into a combination of 4- to 16-inch diameter trunk lines for transportation and delivery into the Basin system at Jal, Wink and Midland as well as our terminal facilities in Midland, Texas. These systems are subject to tariff rates regulated by either the FERC or state regulatory agencies. For 2011, combined throughput on the Permian Basin area systems totaled an average of approximately 404,000 barrels per day.

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 two outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system at Las Flores receives crude oil from ExxonMobil s Santa Ynez field, while the system at Gaviota receives crude oil from the Plains Exploration and Production Company-operated Point Arguello field. These systems both terminate at our Emidio Station. 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.

A portion of our transportation segment profit on Line 63 and Line 2000 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.

2010

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, 2009 2008

2007

Average daily volumes received from:					
Point Arguello (at Gaviota)	5	6	6	7	8
Santa Ynez (at Las Flores)	30	33	34	38	38
Total	35	39	40	45	46

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 144-mile trunk pipeline (of which 102 miles is 14-inch pipe and 42 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 5 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 148 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 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.

Table of Contents

During the fourth quarter of 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. For 2011, combined throughput on Line 63 totaled an average of approximately 61,000 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 (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 approximately 130,000 barrels per day. During 2011, throughput on Line 2000 (excluding Line 63 volumes) averaged approximately 53,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We operate the Salt Lake City Area systems, in which we own interests of between 75% and 100%. The Salt Lake City Area systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. The Salt Lake City Area systems consist of 731 miles of pipelines and approximately 1 million barrels of storage capacity. These systems have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, Wyoming, (ii) approximately 49,000 barrels per day from Wamsutter, Wyoming to Wahsatch, Utah and (iii) approximately 120,000 barrels per day from Wahsatch, Utah to Salt Lake City, Utah. For 2011, throughput on the Salt Lake City Area systems in total averaged approximately 137,000 barrels per day.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system, in which we own an aggregate undivided joint interest of approximately 54%, is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. We also own a 100% interest in approximately 720,000 barrels of tankage located at Patoka, Illinois.

Shell Pipeline Company LP is the operator of this system through August 2013. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, it has two active docks capable of handling approximately 600,000-barrel tankers and is connected to the Louisiana Offshore Oil Port and our St. James terminal and transports sweet and light sour foreign crude to PADD II. Total designed operating capacity is approximately 1.1 million barrels per day of crude oil, of which our attributable interest is approximately 600,000 barrels per day. Throughput on our interest averaged approximately 160,000 barrels per day during 2011.

Central US

Mid-Continent Area Systems. We own and operate pipeline systems that source crude oil from the Cleveland Sand, Granite Wash and Mississippian/Lime resource plays of Western and Central Oklahoma, Southwest Kansas and the eastern Texas Panhandle. These systems consist of over 2,000 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2011, combined throughput on the Mid-Continent Area systems totaled an average of approximately 213,000 barrels per day.

Canada

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system consists of a 554 mile, 8-inch to16-inch mainline pipeline and 667 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Total average throughput during 2011 on the Rangeland system was approximately 59,000 barrels per day.

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system consists of a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 114 miles of gathering pipelines. The system has a throughput capacity of approximately 220,000 barrels per day and transported approximately 135,000 barrels per day during 2011.

Table of Contents

Manito. We own a 100% interest in the Manito heavy oil system. This 555-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line which delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 334 miles of pipeline, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 137 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 pipeline system and can both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2011, approximately 66,000 barrels per day of crude oil were transported on the Manito system.

Pipeline and Gathering Systems Under Construction and Under Development

Basin System Expansion. During 2011, we commenced two expansion projects on the Basin system to increase pipeline capacity. Capacity on crude oil movements from Colorado City, Texas to Cushing, Oklahoma will be increased from 400,000 to approximately 450,000 barrels per day and capacity on the segment from Hendrick to Midland will be increased from 145,000 to approximately 240,000 barrels per day. These projects are expected to be completed in the second quarter of 2012.

Rainbow II Pipeline Expansion. During 2011, we commenced an expansion project for the construction of a 187-mile pipeline to transport condensate and butane from Edmonton, Alberta to our Nipisi truck terminal. Subject to regulatory approval, we expect the project to be in service by the second half of 2013.

Bone Spring Project. During the second quarter of 2011, we commenced construction of an expansion project serving the Bone Spring play in West Texas. The project includes adding six miles of new 6 pipe to an existing system and constructing 20 miles of new 12 pipe and 15 miles of new 10 pipe. The project is designed to initially transport up to approximately 65,000 barrels per day of crude oil and will provide additional take-away capacity for emerging production in Reeves and Ward counties in West Texas. These pipelines will interconnect with our Basin system at Hendrick. We also are constructing up to approximately 100,000 barrels of new storage and terminalling capacity that will be brought on-line in stages. The project is expected to be in service by the first quarter of 2012.

Eagle Ford Area Projects. During 2011, we commenced construction of a new 130-mile crude oil and condensate pipeline, a marine terminal facility and 1.5 million barrels of storage capacity to service Eagle Ford production in South Texas. The project is designed to provide approximately 300,000 barrels per day of take-away capacity from the western region of the Eagle Ford play to Corpus Christi, Texas refining markets and other Gulf Coast markets and is supported by a long-term throughput agreement. PAA has agreed to provide Chesapeake Midstream Development, L.P. the opportunity to acquire up to a 25% joint ownership interest in the project. Additionally, PAA and Flint Hills Resources have executed a Memorandum of Understanding regarding Flint Hills potential joint ownership in this project. We expect to have a 50% ownership interest in this pipeline system, and anticipate it to be in service during the fourth quarter of 2012.

During November 2011, we acquired from Velocity a condensate and crude oil gathering and pipeline system (the Gardendale Gathering System) that is in the advanced stages of construction in the Eagle Ford area of South Texas. The Gardendale Gathering System consists of 120 miles of pipeline with an initial capacity of approximately 150,000 barrels per day and terminals at Gardendale and Catarina with aggregate storage capacity of approximately 185,000 barrels. We have commenced projects to (i) complete current construction, (ii) extend the system to access additional condensate barrels and other crude oil-oriented portions of the Eagle Ford play, and (iii) increase terminal capacity at Gardendale from 150,000 barrels to approximately 250,000 barrels. These expansion activities are expected to be completed at various stages over the next 18 to 24 months.

Bakken Area Projects. During 2011, we commenced a series of projects to service crude oil production in the Bakken region. Such projects include (i) the reversal of our currently idle Wascana Pipeline System, which is expected to be in service during the third quarter of 2012, (ii) the proposed construction of the Bakken North Pipeline System, a 80-mile, 12-inch crude oil pipeline with an initial design capacity of approximately 50,000 barrels that will extend from Trenton, North Dakota to the southern end of the Wascana pipeline, which, subject to regulatory approval and timely receipt of applicable permits, we anticipate placing into service in the fourth quarter of 2012, and (iii) the construction of a multi-use rail facility at Ross, North Dakota, with expected completion by the fourth quarter of 2012.

Medford-to-Cushing Pipeline. In January 2012, we completed the conversion of an existing Oklahoma LPG pipeline into crude oil service. The pipeline extends from Medford, Oklahoma to our terminal facility at Cushing. The pipeline provides an initial crude oil throughput capacity of 12,000 barrels per day and will be expanded to 25,000 barrels per day by July 2012.

Mississippian Lime Pipeline. In early 2012, we announced plans to construct a new 170-mile pipeline to service the increasing Mississippian Lime crude oil production in northern Oklahoma and Southern Kansas. This pipeline will be designed to provide approximately 150,000 barrels per day (approximately 175,000 barrels per day in conjunction with the Medford-to-Cushing pipeline conversion) of crude oil transportation to our terminal facilities at Cushing and is expected to be completed in mid-2013.

18

Table of Contents
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, LPG and natural gas, LPG fractionation and isomerization services and natural gas processing 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 storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products or LPG from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (iv) revenues from the sale of natural gas, (v) fees from LPG fractionation and isomerization and (vi) fees from gas processing services.
As of December 31, 2011, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:
• approximately 71 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
• approximately 9 million barrels of NGL/LPG storage capacity;
approximately 76 Bcf of natural gas storage working capacity;
• approximately 14 Bcf of base gas in storage facilities owned by us;
• a fractionation plant in Canada with a processing capacity of approximately 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of approximately 26,000 barrels per day; and
• four natural gas processing plants located in the Gulf Coast area.

The following is a tabular presentation of our active facilities segment storage and service assets in the United States and Canada as of

December 31, 2011, grouped by product and service type and capacity and throughput as indicated:

Crude Oil and Refined Products Storage Capacity	
(Capacity in millions of barrels)	
Cushing	19
Kerrobert	1
LA Basin	9
Martinez and Richmond	5
Mobile and Ten Mile	3
Patoka	5
Philadelphia Area	4
St. James	7
Yorktown (1)	6
Other	12
	71
NGL/LPG Storage Capacity	
(Capacity in millions of barrels)	
Bumstead	2
Tirzah	1
Other	6
	9
NGL/LPG Fractionation and Isomerization	
(Average throughput in barrels per day)	
California (Fractionation and Isomerization) & Canada (Fractionation)	14,000
Natural Gas Storage Capacity	
(Capacity in billions of cubic feet)	
Salt-caverns (Pine Prairie and Southern Pines)	50
Depleted Reservoir (Bluewater)	26
	76
Gas Processing Facilities	NI/A (2)
ous i rocessing i demotes	N/A (2)

⁽¹⁾ Amount includes 1.6 million barrels of capacity for which we hold lease options (1.1 million barrels of which have been exercised).

The following discussion contains a detailed description of our more significant facilities segment assets.

⁽²⁾ Volumes are not presented as they currently are not a significant driver of our segment results.

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Major Facilities Assets, Including Those Under Construction and Under Development

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 approximately 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.

Since 1999, we have completed multiple expansions, which have increased the capacity of the Cushing Terminal to a total of approximately 19 million barrels. During 2011, we completed our Phase IX, X and XI expansion projects. These projects included adding a new pipeline interconnect and approximately 4 million barrels of storage capacity through the construction of sixteen 270,000 barrel tanks.

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. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels.

L.A. Basin. We own five crude oil and refined product storage facilities in the Los Angeles area with a total of approximately 9 million barrels of useable storage capacity and a distribution pipeline system of approximately 50 miles of pipeline in the Los Angeles Basin. Approximately 8 million barrels of the storage capacity are used for commercial service and approximately 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. Our Los Angeles area system s pipeline distribution assets connect our storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin.

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 have 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 and our Richmond terminal is also able to receive products by train.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that has current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility, which is connected to our Mobile Terminal via a 36-inch pipeline. Approximately two-thirds 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.

Patoka Terminal. Our Patoka Terminal has approximately 5 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Patoka is a growing regional hub with access to domestic and foreign crude oil for certain volumes moving north on the Capline system as well as Canadian barrels moving south. Early in 2011, we commenced construction of Phase IV at our Patoka Terminal, which includes two 286,000 barrel crude oil tanks and one 400,000 barrel crude oil tank. This new tankage is expected to be completed in the second quarter of 2012.

Table of Contents

Philadelphia Area Terminals. We own four refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have a combined storage capacity of approximately 4 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. The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

St. James Terminal. We have approximately 7 million barrels of crude oil storage capacity at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. The facility includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past few years, we completed the construction of a marine dock that is able to receive from tankers and receive from, and load, barges. The facility is also connected to a third party rail-unloading facility. The rail facility, which is exclusively connected to our St. James Terminal, has been expanded to unload 52 rail cars at a time and has capacity to unload 120,000 barrels of sweet crude oil per day. We are currently receiving approximately 60,000 barrels of crude oil per day by rail.

During the third quarter of 2011, we commenced our Phase IV expansion at the St. James Terminal. This project will include construction of an additional 1.0 million barrels of crude oil storage capacity. Completion of this expansion will bring total storage capacity at St. James to approximately 8 million barrels. The project is supported by multi-year contracts and throughput arrangements with third-party customers. We expect to complete Phase IV during the third quarter of 2012.

Yorktown Terminal. During the fourth quarter of 2011, we acquired the idled Western Refinery in Yorktown, Virginia and are operating it as a terminal. This facility has approximately 6 million barrels of storage for crude oil, black oil, propane, butane, and refined products, including 1.6 million barrels of capacity for which we hold lease options. The Yorktown facility has its own deep-water port on the York River with the capacity to service the receipt and delivery of product from ships and barges. This facility also has an active truck rack and rail capacity. We are in the process of making a number of modifications to the Yorktown facility, which will enhance the capabilities of the rail system, the dock facilities and increase connectivity and flexibility within the terminal itself. We expect to complete these projects by the second quarter of 2013.

Pier 400. This is a project 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.

The Environmental Impact Report (EIR) on this project was approved by the Board of Harbor Commissioners of the Port of Los Angeles on November 20, 2008. The EIR was challenged and on January 19, 2010, a final court ruling was issued in our favor. The California South Coast Air Quality Management District issued the Title V permits to construct and operate the facilities on October 6, 2011. Construction of the Pier 400 project is still subject to the completion and execution of a land lease with the Port of Los Angeles and the receipt of certain other regulatory approvals, as well as the completion of commercial arrangements with potential customers. We have approximately \$95 million of capitalized project costs on our balance sheet as of December 31, 2011. We expect to be in a position in 2012 to determine whether or not we will develop this project.

NGL/LPG Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With approximately 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.

During 2010, we began upgrading and improving our Bumstead LPG storage facility, which will increase the useable capacity by approximately 700,000 barrels. This project is expected to be completed in mid-2012.

Tirzah. The Tirzah facility is located in South Carolina and consists of an underground granite storage cavern with approximately 1 million barrels of useable capacity. The Tirzah facility is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline.

NGL/LPG Fractionation and Isomerization

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of NGL. The primary assets consist of approximately 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of approximately 14,000 barrels per day and NGL fractionation capacity of approximately 12,000 barrels per day. During 2011, we commenced our Shafter Expansion Project. This project will include the construction of a 15-mile NGL pipeline system that will be capable of delivering up to 10,000 barrels per day from Occidental Petroleum Corporations s Elk Hills Gas plant to our Shafter facility. It will also include enhancements to our storage and rail facilities. The project is expected to be placed into service in the second quarter of 2013.

Table of Contents

Natural Gas Storage Facilities

Salt Cavern Storage Facilities. We own two FERC regulated, high deliverability salt cavern natural gas storage facilities located on the Gulf Coast. Our Pine Prairie facility is located in Evangeline, Rapides and Acadian Parishes, Louisiana and is permitted for up to 80 Bcf of working gas capacity, which includes 32 Bcf of incremental capacity that was recently approved by the FERC subject to the requirement that Pine Prairie conducts an open season consistent with applicable FERC policy. Our Southern Pines facility is located in Greene County, Mississippi and is permitted for up to 40 Bcf of working gas capacity. These two facilities had an aggregate working gas capacity as of December 31, 2011 of approximately 50 Bcf. During 2012, we anticipate placing an additional 16 Bcf of working gas capacity in service at these facilities, which will include a fifth cavern at Pine Prairie that is scheduled to be placed into service in the second quarter of 2012, a fourth cavern at Southern Pines that is scheduled to be placed into service in the third quarter of 2012 and additional capacity at both facilities from fill/dewater or solution mining under gas operations.

Both of these facilities are strategically-located and have attracted a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and LNG importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hubs, including the Henry Hub, the Carthage Hub and the Perryville Hub, and to existing and proposed LNG import and export facilities.

Pine Prairie s pipeline header system, which includes an aggregate of approximately 80 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States. Pine Prairie s peak daily injection and withdrawal rates are 2.4 Bcf and 3.2 Bcf, respectively, and Pine Prairie has a total of 71,000 horsepower of compression capacity currently in service with another 27,500 horsepower of permitted capacity.

Southern Pines pipeline header system, which includes an aggregate of approximately 60 miles of 24-inch diameter pipe, is directly or indirectly connected to 8 major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern US markets. Southern Pines peak daily injection and withdrawal rates are 1.2 Bcf and 2.4 Bcf, respectively, and Southern Pines has a total of 48,000 horsepower of compression capacity currently in service.

Bluewater. Bluewater is located in the State of Michigan which contains more underground natural gas storage capacity than any other state in the U.S. according to EIA data. Bluewater primarily services seasonal storage needs throughout the Midwestern and northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater s customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario. Bluewater s peak daily injection and withdrawal rates are 0.5 Bcf and 0.8 Bcf, respectively.

Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. Bluewater has filed an application with the FERC to build a 20 pipeline that will be permitted for up to 300 MMcf per day and will connect its facility to a

Canadian pipeline owned by an affiliate of Spectra Energy. The proposed pipeline is intended to replace a 12 pipeline that is permitted for up to 250 MMcf per day and is currently leased from Nova Chemical through January 2013.

Natural Gas Processing

We own and operate four natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of 1.2 Bcf per day. In early 2012, we announced plans to construct a cryogenic gas processing plant near Ross, North Dakota. The plant, if constructed, is expected to be sized to process 50 to 75 million cubic feet per day of gas and is scheduled to be in service in 2013.

Supply and Logistics Segment

Our supply and logistics segment operations generally consist of the following merchant related 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 waterborne 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;

Table of Contents

•	the purchase of LPG from producers, refiners and other marketers;
• profits; an	the resale or exchange of crude oil and LPG at various points along the distribution chain to refiners or other resellers to maximize d
•	the transportation of crude oil and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to various delivery points.
variety of (including and termin positions u	rity of activities that are carried out within our supply and logistics segment are designed to produce a stable baseline of results in a market conditions, while at the same time provide upside potential associated with opportunities inherent in volatile market conditions opportunities to benefit from fluctuating crude oil quality differentials). These activities utilize storage facilities at major interchange nalling locations and various hedging strategies to provide a balance. The tankage that is used to support our arbitrage activities as to capture margins in a contango market or when the market switches from contango to backwardation. See Impact of Commodity attility and Dynamic Market Conditions on Our Business Model below for further discussion.
also owne arrangeme	n to substantial working inventories associated with its merchant activities, as of December 31, 2011, our supply and logistics segment d significant volumes of crude oil and LPG classified as long-term assets for linefill or minimum inventory requirements under service ents with transportation carriers and terminalling providers. The supply and logistics segment also employs a variety of owned or vsical assets throughout the United States and Canada, including approximately:
•	9 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;
•	622 trucks and 731 trailers; and
•	2,453 railcars (all of which are leased).
	tion with its operations, the supply and logistics segment secures transportation and facilities services from our other two segments as rd-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 supply and logistics 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, generally under longer term arrangements.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2011 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	742
LPG sales	103
Waterborne cargos	21
Supply & Logistics activities total	866

Crude Oil and LPG Purchases. We purchase crude oil and LPG from multiple producers under contracts and believe that we have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. These contracts generally range in term from a thirty-day evergreen to five years, with a limited number of contracts extending to ten years and the majority ranging from thirty days to one year. We utilize our truck fleet and gathering pipelines as well as leased railcars, 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 it on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that generally 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.

Table of Contents

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil and refined products 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 integrated oil companies, large independent producers or other LPG marketing companies. Crude oil, refined products and LPG are purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil, refined products 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 activities involved in the supply, logistics and distribution of crude oil and LPG are complex and require current detailed knowledge of crude oil and LPG sources and end markets, as well as 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. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. The contracts generally range in term from a thirty-day evergreen to three years, with a limited number of contracts extending to three years and the majority being approximately thirty-day to one year. We establish a margin for the crude oil and LPG we purchase by entering into physical sales contracts with third parties, 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 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.

Credit. Our merchant activities involve the purchase of crude oil, natural gas, refined products and LPG 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 and, to a lesser extent, standby letters of credit issued under our hedged inventory facility or our senior unsecured revolving credit facility.

When we sell crude oil, LPG, refined products and natural gas, 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, prepayment, letters of credit 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 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 natural gas; 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 up to 100% of their contracted amounts.

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

Table of Contents

Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model

Through our three business segments, we are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, LPG and natural gas. The majority of our activities are focused on crude oil, which is the principal feedstock used by refineries in the production of transportation fuels.

Crude oil, LPG, refined products and natural gas commodity prices have historically been very volatile. For example, over the last 24 years, NYMEX West Texas Intermediate crude oil benchmark prices have ranged from a low of approximately \$10 per barrel during 1986 to a high of over \$147 per barrel during 2008. During 2011, crude oil prices traded within a range of \$75 to \$115 per barrel.

Absent extended periods of lower crude oil prices that are below production replacement costs or higher crude oil prices that have a significant adverse impact on consumption, demand for the services we provide in our fee-based transportation and facilities segments and our gross profit from these activities have little correlation to absolute oil prices. Relative contribution levels will vary from quarter-to-quarter due to seasonal and other similar factors, but our fee-based transportation and facilities segments should comprise approximately 70% to 80% of our aggregate base level segment profit.

Base level segment profit from our supply and logistics 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 adversely affected during certain transitional periods, our crude oil supply, logistics and distribution 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.

In developing our business model and allocating our resources among our three segments, we attempt to anticipate the impacts of shifts between supply-driven markets and demand-driven markets, seasonality, cyclicality, regional surpluses and shortages, economic conditions and a number of other influences that can cause volatility and change market dynamics on a short, intermediate and long-term basis. Our objective is to position the Partnership such that our overall annual base level of cash flow is not materially adversely affected by the absolute level of energy prices, shifts between demand-driven markets and supply-driven markets or other similar dynamics. We believe the complementary, balanced nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets provides us with a durable base level of cash flow in a variety of market scenarios.

In addition to providing a durable base level of cash flow, this approach is also intended to provide opportunities to realize incremental margin during volatile market conditions. For example, if crude oil prices are high relative to historical levels, we may hedge some of our expected pipeline loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge part of the fuel needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, LPG or natural gas in the near term, the market for such product is often in contango, meaning that the price for future deliveries is higher than current prices. In a contango market, entities that have access to storage at major trading locations can purchase crude oil, LPG or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices. Conversely, when there is a higher demand than supply of crude oil, LPG or natural gas in the near term, the market is backwardated, meaning that the price for future deliveries is lower than current prices. In a backwardated market, hedged positions established in a contango market can be unwound, with the physical product or futures position sold into the current higher priced market at a level that more than compensates for any loss associated with closing out future delivery obligations.

The combination of a high level of fee-based cash flow from our transportation and facilities segments, complemented by a number of diverse, flexible and counter-balanced sources of cash flow within our supply and logistics segment is intended to enable us to accomplish our objectives of maintaining a durable base level of cash flow and providing upside opportunities. In executing this business model, we employ a variety of financial risk management tools and techniques, predominantly in our supply and logistics segment.

Risk Management

In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative 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 management s assessment of the cost or benefit in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in our core business; rather, those risks arise as a result of engaging in the trading activity. Our policy is to manage the enterprise level risks inherent in our core businesses, rather than trying to profit from trading activity. Our risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions, as well

Table of Contents

as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities 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. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses.

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 or derivative products for the purpose of speculating on outright commodity price changes.

Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, refined products, LPG and natural gas from thousands of locations and may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions and other uncontrollable events that occur within each month. 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. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

Geographic Data; Financial Information about Segments

See Note 13 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its affiliates accounted for approximately 16% of our revenues for the year ended 2011 and approximately 14% for each of the two years ended December 31, 2010 and 2009. ConocoPhillips Company accounted for approximately 10%, 10% and 12% of our revenues for the years ended December 31, 2011, 2010 and 2009, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2011, 2010 and 2009. The majority of revenues from these customers pertain to our supply and logistics 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 cost of moving an incremental barrel of crude oil. In addition, in areas where additional infrastructure is necessary to accommodate new or increased production or changing product flows, we face competition in providing the required infrastructure solutions as well as the risk of building capacity in excess of sustained demand.

We also face competition with respect to our supply and logistics and facilities services. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, 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, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers also have existing storage facilities connected to their systems that compete with some of our facilities.

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

Table of Contents

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. In 2010 we settled by means of separate Consent Decrees, two ongoing Department of Justice (DOJ)/Environmental Protection Agency (EPA) proceedings regarding certain releases of crude oil. One Consent Decree applies to a specific system. The other (the General Consent Decree) applies to our crude oil pipelines in general. Although we believe that all material aspects of the injunctive elements of the Consent Decrees (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors.

The 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 changes 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.

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 Pipeline and Hazardous Materials Safety Administration (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.

United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act (PIPES Act) of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (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. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately \$32 million in 2011, \$31 million in 2010, and \$25 million in 2009. Based on currently available information, our preliminary estimate for 2012 is that we will incur approximately \$14 million in operational expenditures and approximately \$21 million in capital expenditures associated with our pipeline integrity management program. 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 2002 and 2006 amendments.

On December 13, 2011, the United States Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act). The President signed the Act into law on January 3, 2012. Under the Act, maximum civil penalties for certain violations have been increased from \$100,000 to \$200,000 per violation per day, and from a total cap of \$1 million to \$2 million. In addition, the Act reauthorizes the federal pipeline safety programs of PHMSA through September 30, 2015, and directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in additional natural gas and hazardous liquids pipeline safety rulemaking. Some of these directives include:

Table of Contents

- The Secretary of Transportation must revise regulations establishing time limits for notification of pipeline facility accidents and incidents to a minimum of not more than 1 hour after discovery of an accident or incident;
- The Secretary of Transportation must submit a report to Congress on leak detection systems utilized by operators and promulgate, where technically, operationally and economically feasible, regulations requiring leak detection systems where practicable;
- Within 12 months, the Secretary of Transportation must submit to Congress a report on the results of a study of hazardous liquid pipeline incidents at crossings of inland water bodies at least 100 feet wide, to determine if depth of cover over the buried pipe was a factor in any release of hazardous liquids;
- Within 12 months, the Secretary of Transportation must submit to Congress a report providing information on the total number of authorized full-time positions for pipeline inspection and enforcement at the PHMSA, the total number of positions not filled, the action being taken to fill the vacant positions and any additional inspection and enforcement resource needs of the PHMSA;
- Within 18 months, the Secretary of Transportation must conduct an evaluation to determine whether integrity management system requirements already in place for pipelines in High Consequence Areas (HCAs) should be expanded to pipelines beyond HCAs;
- Within two years, the Secretary of Transportation must submit to Congress a report on the results of a review of existing federal and state regulations for gas and hazardous liquid gathering lines located offshore, including within inlets of the Gulf of Mexico, for the purpose of determining whether the Secretary should issue regulations subjecting offshore gathering lines to the same standards and regulations as other hazardous liquid gathering lines; and
- Within two years, the Secretary of Transportation must determine whether to require the use of automatic or remote-controlled shut-off valves on new and entirely replaced transmission pipeline facilities.

A number of the provisions of the Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. Any additional requirements resulting from these directives are not expected to impact us differently than our competitors. We will work closely with our industry associations to participate with and monitor DOT-PHMSA s efforts.

In December 2009, PHMSA finalized a new rule dictating the shape and content of new control room management programs for hazardous liquid, gas transmission and distribution pipelines. The rule addresses human factors, including fatigue and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition systems. The new rule became effective on February 1, 2010 and requires that control room management plans be written by August 1, 2011, which we completed on time. Implementation of certain aspects such as fatigue training for Controllers and Supervisors, Change Management, Operating Experience and establishing Shift Change procedures was required and completed by October 1, 2011. Implementation for the remaining aspects of the rule is required by August 1, 2012. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate fully implementing the

remaining provisions prior to the established deadline.

We have an internal review process in which we examine the condition and operating history of our pipelines and gathering assets to determine if any of our assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from U.S. 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.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of intrastate pipelines. In practice, states vary in their authority and capacity to address pipeline safety. We do not anticipate any significant issues 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 an attack.

The DOT has adopted American Petroleum Institute Standard 653 (API 653) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. In the United States, costs associated with this program were approximately \$22 million, \$25 million, and \$22 million in 2011, 2010, and 2009, respectively. For 2012, we have budgeted approximately \$32 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

Canada

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.

28

Table of Contents

We have incurred and will continue 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 \$35 million in 2011, \$23 million in 2010, and \$20 million in 2009 on these types of costs. Our preliminary estimate for 2012 is approximately \$62 million.

Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements (including the Consent Decrees, to the extent applicable), 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 (including the General Consent Decree) 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. We believe that our operations are in substantial compliance with applicable occupational health and safety requirements.

Solid Waste

We generate wastes, including hazardous wastes, which are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, (RCRA) and analogous state and provincial laws. Many of the wastes that we generate are not subject to the most stringent requirements of RCRA 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 hazardous wastes under RCRA, 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. 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.

Table of Contents

In conjunction with our acquisitions, we typically 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 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 Energy LLC (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, 2011, we had incurred approximately \$22 million of remediation costs associated with these sites, while SOP s share has been approximately \$11 million.

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

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.

Air Emissions

Our U.S. operations are subject to the U.S. Clean Air Act (Clean Air Act), comparable state laws and associated state and federal regulations. Our Canadian operations are subject to federal and provincial air emission regulations. In 2010, the Canadian Council of Ministers of the Environment agreed to move forward to finalize a new air quality management system. The new Canadian standards for air quality and industrial air emissions are currently in development, with implementation expected to begin in 2013. Under these laws, permits may be required before construction can commence on a new or modified 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

Canada

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 1997 United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. The Kyoto Protocol required Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012. However, by 2009, emissions in Canada were 17% higher than 1990 levels. In December 2011, Canada withdrew from the Kyoto Protocol, but signed the Durban Platform committing it to a legally binding treaty to reduce GHG emissions, the terms of which are to be defined by 2015 and are to become effective in 2020. Environment Canada continues to promote the domestic GHG initiatives implemented while Canada was signatory to the Kyoto Protocol.

In 2007, in response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (also known as the Turning the Corner measures) a regulatory framework for regulating industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Originally, this framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Since 2004, companies emitting more than 100 thousand tons per year (kt/y) of CO2 equivalent (CO2e) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. The current operations of PMC fall well below this 50 kt/y threshold.

In Alberta, the provincial government implemented the *Specified Gas Emitters Regulation* in 2007 (under the Alberta Environmental and Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over 2003-2005 levels for all facilities emitting more than 100 kt/y of CO2e. It is anticipated that the threshold for this regulation will be reduced in future years. Alberta also has a GHG reporting threshold at 50 kt/y of CO2e. Again, emissions from PMC s facilities are well below the 50 kt/y threshold.

Table of Contents

In April 2010, Environment Canada proposed the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* under the Canadian Environmental Protection Act (CEPA). Transportation is one of the largest sources of GHG emissions in Canada, accounting for about 27% of total GHG emissions in 2007. Passenger cars and light trucks account for approximately 12% of total GHG emissions or 45% of transportation emissions. The objective of the proposed regulations is to reduce GHG emissions by establishing mandatory GHG emission standards for new vehicles of the 2011 and later model years that are aligned with U.S. standards. The alignment of vehicle emission standards across North America will provide a level playing field for North American automobile manufacturers. The governments of Canada and the U.S. are consulting to develop aligned regulations to reduce emissions from heavy-duty trucks. In December 2010, the Canadian federal government finalized the *Renewable Fuel Regulations* under CEPA. These regulations require an annual average renewable content of five percent in gasoline and will require a two percent renewable content in diesel fuel and heating oil by 2011. These requirements are further intended to reduce GHG emissions in the truck transportation sector have been announced.

In August 2011, Environment Canada released the text of the proposed regulations to reduce emissions from the coal-fired electricity sector. The proposed regulations apply a stringent performance standard to coal-fired electricity generated units. The standard will be based on parity with the emissions performance of high-efficiency natural gas generation. This is expected to promote replacement of coal-fired units that are reaching the end of their economic life, and will encourage investment in cleaner generation technologies, such as high-efficiency natural gas generation and renewable energy, as well as the use of carbon capture and storage. Regulations are scheduled to come into effect in July 2015, and are likely to stimulate increased demand for natural gas. No other regulatory initiatives to reduce GHG emissions in the electricity sector have been announced.

With regard to the oil and gas industry and the pipeline transportation sector, it is unclear at this time what direction the government plans to take. However, given that there have been no specific regulatory changes announced to date regarding GHG emissions reduction in these sectors; any future initiatives would likely not take effect until beyond 2015.

United States

The United States is not participating in the Kyoto Protocol, and there has not been significant activity with respect to reducing GHG emissions at the federal level in recent years.

In 2009, the U.S. EPA adopted rules for establishing a GHG emissions reporting program. Fewer than ten of our facilities are presently subject to the federal GHG reporting requirements. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds. We import sufficient quantities of finished fuel products into the U.S. to be required to report that activity as well. We also continue to monitor GHG emissions for all of our facilities and activities. At the present time, we do not anticipate the need to purchase GHG credits or install control technology to reduce GHG emissions at any of our facilities.

In 2010, the EPA promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHG s. Fewer than ten of our existing facilities are potential major sources of GHG subject to these permitting requirements. In the absence of any control requirements for GHG s for our facilities that would need to be incorporated into existing Title V permits, we believe the impact of these permitting requirements on our facilities will be minimal.

In the absence of federal climate legislation in the U.S., a number of regional efforts have emerged aimed at reducing GHG emissions. Two of the more significant non-federal GHG programs are the Regional Greenhouse Gas Initiative (RGGI) and the Western Climate Initiative (WCI). RGGI, which includes a number of states in the northeastern U.S., implemented a cap-and-trade program in 2009. At present, this program only applies to utility power plants. None of our facilities are affected by RGGI.

The WCI includes several western U.S. states, some of which are full (voting) members and some of which are just observers. Of the states involved, only California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (AB32). The California Air Resources Board has published a list of facilities expected to be subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. The rules implementing the AB32 program were finalized in December 2011, and we are still evaluating the impact of this program on our Shafter facility. The compliance objectives of the GHG cap-and-trade program will not kick in until 2013 at the earliest and we do not anticipate any problems in complying with those obligations going forward.

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. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in

Table of Contents

the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events, that could have an adverse effect on our assets and operations.

The operations of our refinery customers could also be negatively impacted by current GHG legislation or new regulations resulting in increased operating or compliance costs. Some of the proposed federal and state cap and trade legislation would require businesses that emit GHG s to buy emission credits from government, other businesses, or through an auction process. In addition, refiners could be required to purchase emission credits for GHG emissions resulting from their own refining operations as well as the fuels they sell. While it is not possible at this time to predict the final form of cap-and-trade legislation, any new federal or state restrictions on GHG emissions could result in material increased compliance costs, additional operating restrictions and an increase in the cost of feedstock and products produced by our refinery customers.

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

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 Railroad Commission of Texas (TRRC) and the California Public Utility Commission (CPUC). The CPUC prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities.

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 (now replaced by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE)) 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 formulaic methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2011, the current index for the five year

Table of Contents

period ending July 2016 is the producer price index for finished goods plus an adjustment factor of 2.65 percent. The previous methodology, which was in place until June 30, 2011, was based on the producer price index for finished goods plus an adjustment factor of 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 and settlement as alternatives to the indexing approach that may be used in certain specified circumstances. Because the indexing methodology for the next five-year period 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.

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. The majority of our transportation segment profit in the U.S. is produced by rates that are either grandfathered or set by agreement with one or more shippers. In Canada, rates are set to cover operating costs and a return on capital, without specific agreements with shippers. Shippers may make application to federal or provincial regulatory agencies if they disagree with rates that have been set.

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: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailer vehicles, (v) drug and alcohol testing, (vi) operation and equipment safety and (vii) 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. We are licensed to operate both intra and inter provincially under the direction of the National Safety Code (NSC) that is administered by Transport Canada. Our for hire service is primarily the transportation of crude oil, condensates and NGLs. We are required under the NCS among other things to monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our trucking operations.

Cross Border Regulation

As a result of our cross border activities, including importation of crude oil, LPG and natural gas 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.

Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission (FTC) issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to \$1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (CFTC) to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In November 2010, the CFTC issued proposed rules to implement their new anti-manipulation authority. The proposed rules would subject violators to a civil penalty of up to the greater of \$1 million or triple the monetary gain to the person for each violation.

Table of Contents

We have not experienced a material impact from the FTC regulations. The CFTC rules are not final. We will continue to monitor the status of proposed rules.

Natural Gas Storage Regulation

PNG is subject to extensive laws and regulations. Our natural gas storage operations are subject to regulatory oversight by numerous federal, state, and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines. The regulatory burden increases our cost of doing business and, consequently, affects our profitability. 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. We do not believe that we are affected by applicable laws and regulations in a significantly different manner than are our competitors.

The following is a summary of the kinds of regulation that may impact our natural gas storage operations. However, our unitholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our natural gas storage operations.

Our natural gas storage facilities provide natural gas storage services in interstate commerce and are subject to comprehensive regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (NGA). Pursuant to the NGA and FERC regulations, storage providers are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. The terms and conditions for services provided by our facilities are set forth in FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC s authority extends to maintenance of accounts and records, terms and conditions of service, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites. Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants including PNG Marketing and PAA Natural Gas Canada to ensure market transparency. FERC regulations require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our natural gas storage facilities and related marketing entities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 (EPAct 2005) and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction 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. EPAct 2005 gives the FERC civil penalty authority to impose penalties for certain violations of up to \$1,000,000 per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

Bluewater provides storage service by means of receipts or deliveries of natural gas at the international border with Canada or within the Province of Ontario. The importation and exportation of natural gas from and to the U.S. and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the NEB. Bluewater, PNG Marketing and PAA Natural Gas Canada have regulatory authorization to import and export natural gas from and to the U.S. and Canada.

The natural gas industry historically has been heavily regulated. New rules, orders, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, orders, regulations or laws or the effect they could have on our business, financial condition, and results of operations or ability to make distributions to our unitholders.

Table of Contents

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 2,400% 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 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 spipeline 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 an 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

Our real property holdings are generally comprised of: (i) parcels of land that we own in fee, (ii) surface leases, underground storage leases and (iii) easements, rights-of-way, permits, crossing agreements or licenses from landowners or governmental authorities permitting the use of certain lands for our operations. We believe we have satisfactory title or the right to use the sites upon which our significant facilities are located, subject to customary liens, restrictions or encumbrances. We have no knowledge of any challenge to the underlying fee title of any material fee, lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material deed, lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses. Some of our real property rights (mainly for pipelines) may be subject to termination under agreements that provide for one or more of: periodic payments, term periods, renewal rights, revocation by the licensor or grantor and possible relocation obligations. We believe that our real property holdings are adequate for the conduct of our business activities and that none of the burdens discussed above will materially (i) detract from the value of such properties or (ii) interfere with the use of such properties in our business.

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including Plains Midstream Canada) employed approximately 3,800 employees at December 31, 2011. None of the employees of our general partner are subject to a collective bargaining agreement, except for nine employees covered by an agreement scheduled for renegotiation in September 2012 and another eight employees covered by another agreement scheduled for renegotiation in September 2013. Our general partner considers its employee relations to be good.

Table of Contents

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 the Qualifying Income Exception imposed by Section 7704 of 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 are not liable for U.S. federal income taxes, and a common unitholder is required to report on the unitholder is federal income tax return the unitholder is 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 dividend payments and are treated as income tax expenses as a result of our restructuring of how we hold our Canadian investment on January 1, 2011. Unitholders may be eligible for foreign tax credits with respect to allocable Canadian witholding and income taxes paid.

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, 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 U.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.

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 (or liabilities for which no partner bears the economic risk of loss). 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

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at risk with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitation described above, in the case of taxpayers subject to the passive loss rules (generally, individuals and certain 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.

Table	αf	Contents

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.

Non-U.S., State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as non-U.S., 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 most states in the United States as well as several provinces in Canada. A unitholder may also be required to file state income tax returns and to pay taxes in various states. As a result of recent organizational restructuring of our Canadian entities as of January 1, 2011, our Canadian-source income will pass through a taxable entity and thus will not be subject to Canadian filing obligations for our unitholders. For 2010 and prior years, a unitholder is 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 by partnership entities that were pass-through entities for tax purposes. Unitholders who are not resident in the United States may have additional tax reporting and payment requirements.

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 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 Individual Retirement Accounts (IRAs) and other retirement plans) and non-U.S. 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, non-U.S. corporation or other non-U.S. 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 non-U.S. unitholders are subject to federal income tax withholding at the highest applicable rate.

Available Information

We make available, free of charge on our Internet website at 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 (SEC).

Table of Contents

Item 1A. Risk Factors
Risks Related to Our Business
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. 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 our investment grade credit rating or the ability to receive open credit could negatively affect our ability to purchase crude oil and NGL supplies or to capitalize on market opportunities.
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 and NGL markets. 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. In addition, our ability to capture potential margin attributable to seasonal and other market variations in supply and demand for NGL is also in part dependent upon our ability to use our NGL storage facilities for merchant activities.
We are exposed to the credit risk of our customers in the ordinary course of our supply and logistics 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 risk policies cannot eliminate all risks. In addition, any non-compliance with our risk policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil or other products we purchase by selling such products for physical delivery to third party users, or by entering into a future delivery obligation under derivative contracts. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. Our policy is not to acquire and hold physical inventory or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of crude oil or other products could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 800,000 barrels of crude oil, refined products and NGL. Although this activity is monitored independently by our risk management function, it exposes us to risks within predefined limits and authorizations.

In addition, our operations involve the risk of non-compliance with our risk policies. We have taken steps within our organization to implement our processes and procedures designed to detect unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our risk policies and procedures, particularly if deception or other intentional misconduct is involved.

Table of Contents

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 supply and logistics 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 capacity as it allows a party to simultaneously purchase production or bulk arrangements 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 supply and logistics 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 supply and logistics segment.

The nature of our business and assets exposes us to significant compliance costs and liabilities. As we add assets, we historically have experienced a corresponding increase in the absolute 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 our 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.

We have a history of incremental additions to the miles of pipelines we own. We have also increased our terminalling and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. Although we have implemented programs intended to maintain the integrity of our assets (discussed below), as we acquire additional assets we historically have observed an increase in the number of releases of liquid hydrocarbons into the environment. 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 requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. The DOT regulations include requirements for the establishment of pipeline integrity management programs. We have also developed and implemented certain integrity measures that go beyond regulatory mandate. A portion of these measures are now incorporated into the 2010 Consent Decrees. See Items 1 and 2. Business and Properties Regulation.

The acquisitions we have completed over the last several years have included pipeline assets with varying ages and maintenance and operational histories. Accordingly, for 2012 and beyond, we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have implemented programs intended to maintain the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have an internal review process pursuant to which we examine various aspects of our pipeline and gathering systems that are not subject to the DOT

Table of Contents

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, a significant event or restrictive regulation could adversely affect our profitability. In addition, these offshore fields have experienced substantial production declines since 1995.

A 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 \$10 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated \$3 million incremental decrease in annual transportation segment profit.

In addition, the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico, as well as the resulting oil spill, may lead to increased governmental regulation of our industry's operations in a number of areas, including health and safety, environmental, and licensing, any of which could restrict the supply of crude oil available for transportation. For example, new legislation has been proposed which would revamp federal oversight of offshore drilling, set new safety standards for drilling equipment and well design, and increase liability limits for offshore drilling companies, among other provisions. Other governmental responses may include deep-water drilling moratoria or other potentially major restrictions on drilling and production. Although we currently have no assets that would directly be affected by such regulation, we cannot predict with any certainty whether such regulation, if enacted, might indirectly affect our business.

Our profitability depends on the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered.

Our profitability could be materially impacted by a decline in the volume of crude oil, natural gas and NGL transported, gathered, stored or processed at our facilities. A material decrease in crude oil or natural gas production or crude oil refining, as a result of depressed commodity prices, natural decline rates attributable to oil and natural reservoirs, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of crude oil, natural gas or NGL handled by our facilities and other energy logistics assets.

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.

Fluctuations in demand can negatively affect our operating results.

Demand for crude oil is dependent upon a variety of factors, including price, 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 impact 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.

Fluctuations in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL products, particularly propane, or other reasons, could result in a decline in the volume of NGL products we handle or a reduction of the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGLs we handle and reduce the margins realized. Our NGL products and their demand are affected as follows:

Table of Contents

Ethane. Ethane is typically supplied as purity ethane and as part of an ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could also adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, either alone or in a mixture with propane, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

Iso-butane. Iso-butane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition of motor gasoline resulting from governmental regulation and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, iso-butane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which could negatively impact our operating results.

If we do not make acquisitions or if we make acquisitions that fail to perform as anticipated, 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 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. 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 to timely and effectively 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 ur

require accestrategy. Ou	and may be significant in size relative to our existing assets and operations. Any material acquisition or internal growth project will ess to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth our ability to maintain our targeted credit profile, including maintaining our credit ratings, could affect our cost of capital as well as ou secute our growth strategy.
Our acquis	ition strategy involves risks that may adversely affect our business.
Any acquis	ition 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;
	the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including rising 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.

Table of Contents

We may not be able to successfully close our pending acquisition of the BP NGL Assets, and even if we are successful, such assets may not perform as anticipated.

As noted above, we have signed a definitive purchase and sale agreement to purchase the BP NGL Assets. The closing of the acquisition of such assets is subject to a variety of conditions, including the receipt of various regulatory approvals. We can give no assurance that all such closing conditions will be satisfied and that we will ultimately be able to successfully close the acquisition of the BP NGL Assets.

In addition, even if we are successful in our efforts to close the acquisition of the BP NGL Assets, there are a variety of factors that may cause such assets to underperform relative to our expectations.

For example, BP has historically operated the BP NGL Assets as an integrated, proprietary business which primarily purchases mixed NGL products and/or NGL processing rights (i.e., extraction rights) in Alberta and then transports, processes, fractionates, stores and sells the purity products in Alberta, Sarnia, Ontario and the upper-Midwest of the U.S. Since a significant portion of the BP NGL Assets is dependent upon Western Canadian wet gas supply, throughput on the BP NGL Assets may continue to be adversely impacted by continued declines in Western Canadian wet gas production, particularly declines in wet gas moving East through the Empress processing facilities where there is excess gas processing capacity and significant competition for gas processing extraction rights.

In addition, the BP NGL Assets are comprised of significant fractionation, storage, and marketing assets in the Sarnia area, which is expected to be a primary market for NGL produced from the Marcellus and Bakken plays, and potentially the Utica Shale area. The assets and markets in and around the Sarnia area may be negatively impacted in the short run by the expected increases in NGL production from the Marcellus and the Bakken due to an increase in NGL products in the area. Over the intermediate and long-term we expect supply volume growth from these resources plays will increase the utilization of the BP NGL Assets in the area; however, we can provide no assurance that will occur.

Table of Contents

Also, BP s historical practices involved limited hedging of the commodity risk inherent in its NGL processing operations which leaves the financial results of the BP NGL Assets exposed to changes in NGL prices. As a result, when and if the acquisition of BP s NGL Assets closes, we will acquire inventories of NGL that are not hedged and are exposed to NGL pricing variations, which we may not be able to hedge at profitable levels. Over time, however, once our risk management controls and procedures are applied to the BP NGL Assets, we intend to reduce this type of exposure through increased hedging and contracting activity.

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 liquids pipelines, which include both crude oil and refined products pipelines, are subject to regulation by the FERC under the ICA. The ICA requires that tariff rates for liquids 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 liquids pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings, file complaints against our existing rates, 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.

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 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.

Our sales of oil, natural gas, NGLs and other energy commodities, and related transportation and hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Legislation and regulatory initiatives relating to hydraulic fracturing could reduce domestic production of crude oil and natural gas.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Recent advances in hydraulic fracturing techniques have resulted in significant increases in crude oil and natural gas production in many basins in the United States and Canada. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, and it is typically regulated by state and provincial oil and gas commissions. The process has recently become subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for our transportation, terminalling and storage services.

We face competition in our transportation, facilities and supply and logistics 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 natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers have existing storage facilities connected to their systems that compete with some of our facilities.

Table of Contents

With regard to our NGL operations, we compete with large oil, natural gas and natural gas liquids companies that may have greater financial resources and access to supplies of natural gas and NGLs than we do. Some of the competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services that we provide to our customers. The principal elements of competition are rates, processing fees (e.g., extraction premiums) paid to the owners or aggregators of natural gas to be processed, geographic proximity to the natural gas or NGL mix, available processing and fractionation capacity, transportation alternatives and their associated costs, and access to end user markets.

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, 2011, our consolidated debt outstanding was approximately \$5.2 billion, consisting of approximately \$4.5 billion principal amount of long-term debt (including senior notes) and approximately \$0.7 billion of short-term borrowings. As of December 31, 2011, we had over \$3.6 billion of available borrowing capacity under our senior unsecured revolving credit facilities, our senior secured hedged inventory facility and PNG s credit agreement.

Table of Contents

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The amount of our current	or future indebtedness	could have significant ef	fects 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 Credit Facilities and Indentures.

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 current maturities and debt maturing in the next several years, 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.

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As of December 31, 2011, we had approximately \$5.2 billion of consolidated debt, of which approximately \$4.7 billion was at fixed interest rates and approximately \$0.5 billion was at variable interest rates (including \$150 million of interest rate derivatives that swap fixed-rate debt for floating). We are exposed to market risk due to the floating interest rates on our credit facilities. 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 supply and logistics 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.

An impairment of goodwill could reduce our earnings.

At December 31, 2011, we had approximately \$1.9 billion of goodwill. 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

Table of Contents

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 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.

A decision to not develop our Pier 400 project could reduce our earnings.

At December 31, 2011, we had \$95 million of capitalized project costs on our balance sheet for the Pier 400 project. Development of the project is still subject to the completion and execution of a land lease with the Port of Los Angeles, receipt of certain other regulatory approvals, as well as completion of commercial contracts with potential customers. If we determine that the project will not be developed, we would be required to take a charge to earnings.

Our natural gas storage facilities may not be able to deliver as anticipated, which could prevent us from meeting our contractual obligations and cause us to incur significant costs.

Although we believe that our operating gas storage facilities have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, if our facilities do not perform as designed and we fail to wheel, inject or withdraw natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to satisfy our contractual obligations.

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

Our supply and logistics operations include purchasing crude oil that is carried on third-party tankers. Our waterborne cargos of crude oil are at risk of being damaged or lost because of events such as marine disaster, inclement 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 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 cargos.

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. If at any time our access to this dock was denied, and if access to an alternative dock could not be arranged, the volume 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.

Terrorist attacks aimed at our assets 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 spipeline infrastructure, may be future targets of terrorist organizations. These historical events will subject our operations to increased risks. Any future terrorist attack that may target our assets, those of our customers and, in some cases, those of other parties, could have a material adverse effect on our business.

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.

Table of Contents

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.

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 may 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 ratio of taxable income to distributions may increase;
• the relative voting strength of each previously outstanding unit may be diminished; and
• the market price of the common units may decline.
Our general partner 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

Table of Contents

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 and/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.

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 to transfer 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 our revolving credit agreements. During the continuance of an event of default under our revolving credit agreements, 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 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.

Our debt securities are effectively subordinated to claims of our and our subsidiaries—secured creditors. In the event of insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up, secured creditors would generally have the right to be paid in full before any distribution is made to the holders of our 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, 2011, our total outstanding debt was approximately \$5.2 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 energy 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.

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 partnership laws and other laws and regulations. Under our credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on outstanding amounts. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt securities, or to repurchase our 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 our debt securities. We cannot assure you that we would be able to refinance our debt securities.

Table of Contents

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 additional entity-level taxation. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes or if we become subject to material amounts of additional entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available to pay distributions and our debt obligations.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

In addition, a change in current law may cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to additional 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. 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, deductions or credits 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 common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

Table of Contents

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 technically 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 our filing two tax returns 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 calendar year, 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 it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

If the IRS or Canada Revenue Agency (CRA) contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS or CRA 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 or CRA 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 or CRA 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.

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 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. Non-U.S. persons will also potentially have tax filing and

Table of Contents

payment obligations in additional jurisdictions. 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.

To maintain the uniformity of the economic and tax characteristics 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 non-U.S. 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 and local 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, 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 non-U.S. tax returns. As a result of the Canadian restructuring, 2010 is the last year that non-Canadian resident unitholders will be required to file Canadian tax returns with respect to an investment in our units.

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.

A unitholder who loans his common units to a short seller to cover a short sale of common units (i) may be considered as having disposed of the loaned units, (ii) 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 (iii) 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.

Table of Contents

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 does not appear as if it would 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.

We 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.

We prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase our units 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 use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration 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.

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None.

Item 3. Legal Proceedings

General. In the ordinary course of business, we are involved 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. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In June 2007, the NJDEP brought suit in the Superior Court of New Jersey against GATX, ExxonMobil and our subsidiary, Plains Products Terminals (PPT), to recover natural resources damages associated with, and to require remediation of, contamination at our Paulsboro terminal facility. ExxonMobil and GATX filed third-party demands against

PPT, seeking indemnity and contribution. The natural resources damages were settled with the State of New Jersey. The settlement agreement was approved by the court in September 2011. PPT s allocated share of this liability is \$550,000, which was paid in November 2011. We remain in dispute with ExxonMobil regarding future remediation responsibility as well as allocation of prior remediation costs.

Bay Area Air Quality Management District (BAAQMD). During the time period from 2008 to the present, we have received from BAAQMD various notices of violation for alleged violations of California air emissions regulations at our Martinez terminal. In December 2011, we entered into a settlement agreement with BAAQMD, pursuant to which we paid \$116,000 in penalties.

Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al. In a case filed in the Texas Southern District Court, Pemex Exploración y Producción (PEP) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S. companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P. PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P. At a hearing held on October 20, 2011, the Court ruled that Texas law (not Mexican law) governs the actions.

Table of Contents
Environmental
General
Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our integrity management procedures, remove selected assets from service and invest capital to upgrade the assets. 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. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.
At December 31, 2011, our estimated undiscounted reserve for environmental liabilities, including the reserve related to our Rainbow Pipeline release as discussed further below, totaled approximately \$74 million, of which approximately \$12 million was classified as short-term and \$62 million was classified as long-term. At December 31, 2010, our estimated undiscounted reserve for environmental liabilities totaled approximately \$66 million, of which approximately \$10 million was classified as short-term and \$56 million was classified as long-term. At December 31, 2011 and December 31, 2010, we had recorded receivables totaling approximately \$47 million and \$5 million, respectively, for amounts 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 information currently available to us 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

currently available to us 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 may be in excess of the reserve and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

Rainbow Pipeline Release

On April 29, 2011, we experienced a crude oil release on a remote section of our Rainbow Pipeline located in Alberta, Canada. Upon detection of the release, approximately 45 miles of the pipeline were isolated and depressurized and emergency response personnel were mobilized to conduct clean-up operations in cooperation with the Alberta ERCB. After completing the pipeline repair and responding to additional regulatory requested pipeline inspections and information requests, we received regulatory approval and restarted full operation of the pipeline on August 30, 2011. We completed the remaining site clean-up, reclamation and remediation activities in December 2011, and have demobilized all equipment and personnel from the site. Post-reclamation environmental monitoring will continue in accordance with regulatory requirements.

The aggregate total estimated cost to clean-up and remediate the site, before insurance recoveries, was approximately \$70 million, which was accrued to field operating costs on our consolidated statement of operations. While we believe this amount to be final, there is a small amount of

work that will require completion during the spring of 2012 with regard to monitoring and land contouring. The costs associated with this work are not expected to be material.

As of December 31, 2011, we have a remaining undiscounted gross environmental remediation liability for the release of approximately \$2 million. This liability is presented as a current liability within the caption Accounts payable and accrued liabilities on our consolidated balance sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, to protect us against such environmental liabilities. As of December 31, 2011, we have a remaining receivable of approximately \$41 million for the portion of this liability that we believe is probable of recovery from insurance, net of deductibles. This receivable has been recognized as a current asset within the caption Trade accounts receivable and other receivables, net on our consolidated balance sheet with the offset reducing operating expense on our consolidated statement of operations.

Insurance

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 certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

Table of Contents

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. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. For example, the market for hurricane-or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, and costs have increased substantially with the combination of premiums and deductibles for the 2010 renewal totaling 20% or more of the coverage limit.

For the two years prior to June 2011, we have purchased a hurricane limit of \$10 million to cover property and business interruption, representing substantially the level of insurance that was available. The coverage provided by these policies contained much stricter limitations than the insurance policies available prior to hurricanes Rita and Katrina. As a result of these conditions, we did not renew this coverage in June 2011 and do not plan to purchase this coverage for 2012. We will, instead, self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have renewed at our historic levels. In addition, although we believe that we have established adequate reserves to the extent 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 conditions, results of operations or cash flows.

Item	4	Mine	Safety	Discl	nsures
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Not applicable.

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. As of February 22, 2012, the closing market price for our common units was \$81.51 per unit and there were approximately 159,000 record holders and beneficial owners (held in street name). As of February 22, 2012, there were 155,568,749 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 Price R	Cash		
	High	Low		Distributions (1)
2011				
4th Quarter	\$ 73.55	\$ 54.90	\$	1.0250
3rd Quarter	\$ 64.98	\$ 56.41	\$	0.9950
2nd Quarter	\$ 65.69	\$ 57.80	\$	0.9825
1st Quarter	\$ 65.96	\$ 60.21	\$	0.9700
2010				
4th Quarter	\$ 65.20	\$ 60.91	\$	0.9575
3rd Quarter	\$ 64.21	\$ 57.33	\$	0.9500
2nd Quarter	\$ 60.06	\$ 44.12	\$	0.9425
1st Quarter	\$ 57.11	\$ 49.82	\$	0.9350

⁽¹⁾ Cash distributions for a quarter are declared and paid in the following calendar quarter. See the Cash Distribution Policy below for a discussion of our policy regarding distribution payments.

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.

Table of Contents

Cash Distribution Policy

In accordance with our partnership agreement, we will distribute all of our available cash to our unitholders within 45 days following the end of each quarter 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.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing the acquisitions of Pacific Energy Partners LP (Pacific) in November 2006, Rainbow Pipe Line Company, Ltd. (Rainbow) in May 2008 and PAA Natural Gas Storage, LLC (PNGS) in September 2009, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions was \$83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007	2008	2009	2010	2011	Total
Pacific	\$ 20	\$ 15	\$ 15	\$ 10 \$	5	\$ 65
Rainbow		3	6	1		10
PNGS			1	5	2	8
Total	\$ 20	\$ 18	\$ 22	\$ 16 \$	7	\$ 83

The final \$1 million of incentive distribution reductions related to these acquisitions was applied to the November 2011 distribution.

On December 1, 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (the BP NGL acquisition). We expect this acquisition will close in the second quarter of 2012, subject to Canadian and U.S. regulatory approvals and customary closing conditions. Upon closing this acquisition, our general partner

has agreed to reduce the amount of its incentive distributions by \$15 million per year for two years, beginning with the first distribution paid following closing. Thereafter, our general partner has agreed to an ongoing reduction of \$10 million per year. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL acquisition.

We paid \$204 million to the general partner in incentive distributions in 2011. Additionally, on February 14, 2012, we paid a quarterly distribution of \$1.025 per unit applicable to the fourth quarter of 2011, of which approximately \$63 million was paid to the general partner in incentive distributions. 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 Credit Facilities and Indentures.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding securities authorized for issuance under equity compensation plans.

Table of Contents

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2011, and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans (LTIP).

Item 6. Selected Financial Data

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2011, 2010, 2009, 2008 and 2007 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,								
		2011		2010		2009	2008		2007
				(in milli	ons, e	except for per unit data	1)		
Statement of operations data:									
Total revenues	\$	34,275	\$	25,893	\$	18,520 \$	30,061	\$	20,394
Net income	\$	994	\$	514	\$	580 \$	437	\$	365
Net income attributable to Plains	\$	966	\$	505	\$	579 \$	437	\$	365
Per unit data:									
Basic net income per limited									
partner unit	\$	4.91	\$	2.41	\$	3.34 \$	2.66	\$	2.47
Diluted net income per limited									
partner unit	\$	4.88	\$	2.40	\$	3.32 \$	2.64	\$	2.45
Declared distributions per limited									
partner unit (1)	\$	3.91	\$	3.76	\$	3.62 \$	3.50	\$	3.28
Balance sheet data (at end of period):									
Total assets	\$	15,381	\$	13,703	\$	12,358 \$	10,032	\$	9,906
Long-term debt	\$	4,520	\$	4,631	\$	4,142 \$	3,259	\$	2,624
Total debt	\$	5,199	\$	5,957	\$	5,216 \$	4,286	\$	3,584
Partners capital	\$	5,974	\$	4,573	\$	4,159 \$	3,552	\$	3,424
•									
Other data:									
Net cash provided by operating									
activities	\$	2,365	\$	259	\$	365 \$	857	\$	796
Net cash used in investing									
activities	\$	(2,020)	\$	(851)	\$	(686) \$	(1,339)	\$	(663)
Net cash provided by/(used in)									
financing activities	\$	(345)	\$	604	\$	338 \$	464	\$	(124)
Capital expenditures:									
Acquisitions	\$	1,404	\$	407	\$	393 \$	735	\$	125
Internal growth projects	\$	531	\$	355	\$	364 \$	491	\$	525
Maintenance	\$	120	\$	93	\$	81 \$	81	\$	50
	\$		\$		\$	15 \$	37	\$	9

Investments in unconsolidated subsidiaries

Table of Contents

Year Ended December 31, 2011 2010 2009 2008 2007 **Volumes (2) (3)** Transportation segment (average daily volumes in thousands of barrels per day): Tariff activities 2,942 2,889 2,836 2,851 2,712 Trucking 105 97 85 97 105 Transportation segment total 3,047 2,986 2,921 2,948 2,817 Facilities segment: Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels) 70 61 56 53 46 Natural gas storage (average monthly capacity in billions of cubic feet) 71 47 26 14 13 LPG processing (average throughput in thousands 15 17 of barrels per day) 14 14 18 Facilities segment total (average monthly capacity 70 56 48 in millions of barrels) 82 61 Supply & Logistics segment (average daily volumes in thousands of barrels per day): Crude oil lease gathering purchases 742 620 612 658 685 LPG sales 103 105 103 90 96 55 71 Waterborne cargos 21 68 80 784 772 Supply & Logistics segment total 866 841 846

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

Introduction

⁽¹⁾ 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.

⁽²⁾ Volumes associated with acquisitions represent total volumes for the number of days or months (dependent on the calculation) we actually owned the assets divided by the number of days or months in the year.

Facilities total is calculated as the sum of: (i) crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products (LPG) storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude British thermal unit (Btu) equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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 discus	sion and analysis includes the following:
•	Executive Summary
•	Company Overview
•	Overview of Operating Results, Capital Investments and Significant Activities
•	Acquisitions and Internal Growth Projects
•	Critical Accounting Policies and Estimates
	59

Table of Contents Recent Accounting Pronouncements Results of Operations Outlook Liquidity and Capital Resources **Executive Summary** Company Overview We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as the processing, transportation, fractionation, storage and marketing of natural gas liquids (NGL). The term NGL includes ethane and natural gasoline products as well as

propane and butane, products which are also commonly referred to as liquid petroleum gas (LPG). The terms NGL and LPG are sometimes used interchangeably within this document depending on the context. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P., we also own and operate 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) Supply and Logistics. See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Investments and Significant Activities

During 2011, our net income attributable to Plains was \$966 million, which was a \$461 million year-over-year increase as compared to that recognized during 2010. This increase was primarily driven by strong industry fundamentals and contributions from our acquisitions and internal growth projects. The major items impacting comparability between periods were:

- the favorable results experienced within our supply and logistics segment, which were impacted by (i) the active development of crude oil and liquids-rich resource plays, (ii) favorable crude oil basis differentials and (iii) favorable market structure;
- the favorable results experienced within our transportation segment, which were impacted by (i) increased volumes in key production areas, (ii) increased tariff rates and (iii) favorable foreign currency exchange rates, partially offset by the unfavorable impact of a crude oil

release on our Rainbow Pipeline; and

the favorable results experienced within our facilities segment, which were impacted by expansions to our asset base through acquisitions and our ongoing internal growth projects. Other key items impacting 2011 were: the completion of nine acquisitions for the aggregate consideration, net of cash acquired, of approximately \$1.3 billion; the issuance of debt and equity for net proceeds of approximately \$1.9 billion (this amount includes PNG s issuance, in conjunction with the Southern Pines Acquisition, of approximately 17.4 million common units to third parties for net proceeds of approximately \$370 million); the increase in our income tax expense related to our Canadian operations as a result of Canadian tax legislation changes that became effective on January 1, 2011; and the redemption of our 7.75% senior notes that were maturing in 2012 for approximately \$222 million, as well as the loss of \$23 million recognized in Other income/(expense), net within our Consolidated Financial Statements in conjunction with the early redemption of these notes.

60

Table of Contents

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2011, 2010 and 2009 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	For the Year Ended December 31,									
	2011		2010		2009					
Acquisition capital (1) (2)	\$ 1,404	\$	407	\$	393					
Internal growth projects	531		355		364					
Maintenance capital	120		93		81					
Investment in unconsolidated entities (1)					15					
	\$ 2,055	\$	855	\$	853					

⁽¹⁾ Initial investments in unconsolidated entities are included within Acquisition capital, whereas additional subsequent investments in unconsolidated entities are recognized within Investment in unconsolidated entities.

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 closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in Liquidity and Capital Resources and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2011, 2010 and 2009 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Southern Pines	02/09/2011	\$ 765	Facilities
Gardendale Gathering System	11/29/2011	349	Transportation
Western	12/29/2011	220	Facilities and Transportation
Other (1)	Various	70	Transportation, Facilities and Supply & Logistics
2011 Total		\$ 1,404	
Nexen	12/30/2010	\$ 229	Supply & Logistics and Transportation
Other	Various	178	Transportation and Facilities
2010 Total		\$ 407	

Acquisition capital for the year ended December 31, 2011 includes a cash deposit of \$50 million (reflected in Other current assets on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

PNGS	09/03/2009	\$ 215	Facilities
Other	Various	178	Transportation and Facilities
2009 Total		\$ 393	

(1) Includes a cash deposit of \$50 million (reflected in Other current assets on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

61

Table of Contents

Internal Growth Projects

Our 2011 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2011, 2010 and 2009 projects (in millions):

Projects	2011	:	2010	2009
PAA Natural Gas Storage (multiple projects) (1) (2)	\$ 89	\$	85	\$ 26
Rainbow II Pipeline (1)	44		3	
Cushing - Phases VII and VIII	3		25	25
Cushing - Phases IX through XI	38		21	
Basile Gas Processing Facility	37		14	2
Ross Rail Project (1)	27			
Bumstead Facility	14		2	
Bone Spring Project (1)	15			
Patoka - Phases I through IV (1)	15		20	22
Eagle Ford Project (1)	18			
Edmonton Land			17	
West Texas Gathering Lines			15	
Pier 400 (1)	13		11	18
Nipisi Storage and Truck Terminal (1)	9		6	18
Kerrobert Pumping Project			1	33
Rangeland Tankage				36
St. James - Phases I through III			21	73
Other projects (3)	209		114	111
Total	\$ 531	\$	355	\$ 364

⁽¹⁾ These projects will continue into 2012. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2012 Capital Expansion Projects.

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

Critical Accounting Policies and Estimates

Critical Accounting Policies

⁽²⁾ Expenditures shown for 2009 for PNGS include only those expenditures made subsequent to the acquisition in September 2009 of the remaining 50% interest in PNGS.

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States (GAAP). 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 GAAP and rules and regulations of the United States Securities and Exchange Commission (SEC) 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. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

We believe that the assumptions, judgments and estimates involved in the accounting for our (i) purchase and sales accruals, (ii) fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, including our equity compensation plan accruals, (v) property and equipment and depreciation expense and (vi) allowance for doubtful accounts have the greatest potential impact on our consolidated financial statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates, so we consider these to be our critical accounting policies. Such critical accounting estimates are discussed further as follows:

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, 2011, we estimate that approximately 2% of both annual revenues and cost of sales were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact annual revenues, cost of sales, operating income and net income attributable to Plains line items by approximately 1% or less 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.

Table of Contents

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with Financial Accounting Standards Board (FASB) guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. With exception to our equity method investments, we also expense the transaction costs as incurred in connection with each 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 future revenues, future cash flows and 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. We did not have any material goodwill impairments in 2011, 2010 or 2009. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

Table of Contents

Fair Value of Derivatives. Our derivatives are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income (AOCI). The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the realized 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. Less than 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, asset retirement obligations, equity compensation plan accruals (as further discussed below) 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, 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 \$17 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.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity compensation awards. Under GAAP, 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. 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.

We recognized total compensation expense of approximately \$110 million, \$98 million and \$68 million in 2011, 2010 and 2009, 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 and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. During 2010 and 2011, we conducted a review to assess the useful lives of our property and equipment. See Note 2 to our Consolidated Financial Statements.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. For example, we are continuing to develop our Pier 400 project in California. Development of the project is still subject

to the completion and execution of a land lease with the Port of Los Angeles, receipt of certain other regulatory approvals, as well as completion of commercial contracts with potential customers. We have capitalized \$95 million of costs associated with this project and would assess the project for impairment if we determine that the project will not be developed. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

• whether there is an event or circumstance that may be indicative of an impairment;

64

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•	the grouping of assets;
•	the intention of holding, abandoning or 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.
were predo	ats of approximately \$5 million, \$13 million and less than \$1 million were recognized during 2011, 2010 and 2009, respectively, and ominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue d, in most instances, we utilized other assets to handle these activities.
conditions based on sp customer c	for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established pecific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for discussion.
Recent Ac	ecounting Pronouncements
See Note 2 statements	to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our financial .
Results of	Operations
Analysis o	f Operating Segments
	e our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment

profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 13 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 net

income attributable to Plains.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the supply and logistics 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 with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our supply and logistics 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 activities 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.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. The primary measures used by management are adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) and implied distributable cash flow (DCF).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and

Table of Contents

planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as Selected Items Impacting Comparability. These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP:

				Ļ					Ļ		
Transportation segment profit	\$ 555	\$	516	\$	477	\$	39	8%	\$	39	8%
Facilities segment profit	358		270		208		88	33%		62	30%
Supply & Logistics segment											
profit	647		240		345		407	170%		(105)	(30)%
Total segment profit	1,560		1,026		1,030		534	52%		(4)	%
Depreciation and amortization	(249)		(256)		(236)		7	3%		(20)	(8)%
Interest expense	(253)		(248)		(224)		(5)	(2)%		(24)	(11)%
Other income/(expense), net	(19)		(9)		16		(10)	(111)%		(25)	(156)%
Income tax benefit/(expense)	(45)		1		(6)		(46)	(4,600)%		7	117%
Net income	994		514		580		480	93%		(66)	(11)%
Less: Net income attributable											
to noncontrolling interests	(28)		(9)		(1)		(19)	(211)%		(8)	(800)%
Net income attributable to											
Plains	\$ 966	\$	505	\$	579	\$	461	91%	\$	(74)	(13)%
Net income attributable to											
Plains:											
Earnings per basic limited											
partner unit	\$ 4.91	\$	2.41	\$	3.34	\$	2.50	104%	\$	(0.93)	(28)%
Earnings per diluted limited											
partner unit	\$ 4.88	\$	2.40	\$	3.32	\$	2.48	103%	\$	(0.92)	(28)%
Basic weighted average units		·				·				()	(-) .
outstanding	149		137		130		12	9%		7	5%
Diluted weighted average	1.,,		10,		-200			,,,		,	2,0
units outstanding	150		138		131		12	9%		7	5%
	100		100		-101			, , ,		,	2,0

Table of Contents

The following table sets forth additional non-GAAP financial measures that are reconciled from the most directly comparable measures as reported in accordance with GAAP:

Net income	\$	994	\$	514	\$	580	\$	480	93%	\$	(66)	(11)%
Add:	φ	77 1	φ	314	φ	300	φ	400	93 /0	φ	(00)	(11)/0
Depreciation and amortization		249		256		236		(7)	(3)%		20	8%
Income tax (benefit)/expense		45		(1)		6		46	4,600%		(7)	(117)%
Interest expense		253		248		224		5	2%		24	11%
EBITDA	\$	1,541	\$	1,017	\$	1,046	\$	524	52%	\$	(29)	(3)%
											, ,	, ,
Selected Items Impacting												
Comparability of EBITDA												
Equity compensation expense												
(1)	\$	(77)	\$	(67)	\$	(50)	\$	(10)	(15)%	\$	(17)	(34)%
Gains/(losses) from other									·			
derivative activities (2)		62		(14)		34		76	543%		(48)	(141)%
Inventory valuation		Ŭ <u>-</u>		(1.)				, 0	0.070		(.0)	(111)/0
adjustments net of gains from												
related derivative activities (2)						24			%		(24)	(100)%
Net loss on early repayment of						24			70		(24)	(100) //
senior notes		(23)		(6)		(4)		(17)	(283)%		(2)	(50)%
Significant acquisition-related		(23)		(0)		(+)		(17)	(203) 10		(2)	(30) 10
expenses		(10)						(10)	N/A			%
Net gain/(loss) on foreign		(10)						(10)	1 (/11			,,
currency revaluation (3)		(7)				12		(7)	N/A		(12)	(100)%
				(2)				(1)	%			
Other (4) Selected Items Impacting		(2)		(2)		8			%		(10)	(125)%
Comparability of EBITDA	\$	(57)	\$	(89)	\$	24	\$	32	36%	\$	(113)	(471)%
Comparability of EBITDA	Ф	(37)	Ф	(09)	Ф	24	Þ	32	30%	Ф	(113)	(4/1)%
EBITDA	\$	1,541	\$	1,017	\$	1,046	\$	524	52%	\$	(29)	(3)%
Selected Items Impacting	Ψ	1,571	Ψ	1,017	Ψ	1,040	Ψ	324	3270	Ψ	(2))	(3) 10
Comparability of EBITDA		57		89		(24)		(32)	(36)%		113	471%
Adjusted EBITDA	\$	1,598	\$	1,106	\$	1,022	\$	492	44%	\$	84	8%
110,0000 2211211	Ψ.	1,000	4	1,100	Ψ.	1,022	Ψ	.,	,	Ψ	Ŭ.	3,0
Adjusted EBITDA	\$	1,598	\$	1,106	\$	1,022	\$	492	44%	\$	84	8%
Interest expense		(253)		(248)		(224)		(5)	(2)%		(24)	(11)%
Maintenance capital		(120)		(93)		(81)		(27)	(29)%		(12)	(15)%
Current income tax												
benefit/(expense)		(38)		1		(15)		(39)	(3,900)%		16	107%
Equity earnings in												
unconsolidated entities, net of												
distributions		10		6		(8)		4	67%		14	175%
Distributions to												
noncontrolling interests (5)		(47)		(15)		(2)		(32)	(213)%		(13)	(650)%
Other		(1)						(1)	N/A		•	%
Implied DCF	\$	1,149	\$	757	\$	692	\$	392	52%	\$	65	9%

Our total equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a											
selected item impacting comparability as the dilutive impact of the outstanding awards are included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The compensation expense associated with these awards is shown as a											
selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 10 to our Consolidated Financial Statements for a											
comprehensive discussion regarding our equity compensation plans.											
(2) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are											
presented with related derivative activity. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.											
(3) During 2011 and 2009, there were significant fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar											
(USD), resulting in gains and losses that were not related to our core operating results of the period and were thus classified as selected items impacting comparability. See Note 6 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk											
hedging activities.											
(4) Includes other immaterial selected items impacting comparability.											
67											

Table of Contents

(5) Includes distributions that pertain to the current quarter s net income and are to be paid in the subsequent quarter.

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.

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

Revenues (1)							
Tariff activities	\$ 1,005	\$ 937	\$ 867	\$ 68	7%	\$ 70	8%
Trucking	160	108	94	52	48%	14	15%
Total transportation revenues	1,165	1,045	961	120	11%	84	9%
Cost and Expenses (1)							
Trucking costs	(115)	(73)	(63)	(42)	(58)%	(10)	(16)%
Field operating costs (excluding							
equity compensation expense)	(387)	(346)	(333)	(41)	(12)%	(13)	(4)%
Equity compensation expense -							
operations (2)	(14)	(12)	(9)	(2)	(17)%	(3)	(33)%
Segment general and administrative							
expenses (excluding equity							
compensation expense)	(69)	(65)	(61)	(4)	(6)%	(4)	(7)%
Equity compensation expense -							
general and administrative (2)	(38)	(36)	(25)	(2)	(6)%	(11)	(44)%
Equity earnings in unconsolidated							
entities	13	3	7	10	333%	(4)	(57)%
Segment profit	\$ 555	\$ 516	\$ 477	\$ 39	8%	\$ 39	8%
Maintenance capital	\$ 86	\$ 67	\$ 57	\$ (19)	(28)%	\$ (10)	(18)%
Segment profit per barrel	\$ 0.50	\$ 0.47	\$ 0.45	\$ 0.03	6%	\$ 0.02	4%

					Favorable/(Un	favorable)		
Average Daily Volumes	Year E	inded December	31,	2011-201	10	2010-2009		
(in thousands of barrels per day) (3)	2011	2010	2009	Volumes	%	Volumes	%	
Tariff activities								
All American	35	39	40	(4)	(10)%	(1)	(3)%	
Basin	440	378	394	62	16%	(16)	(4)%	
Capline	160	223	193	(63)	(28)%	30	16%	
Line 63/Line 2000	114	109	131	5	5%	(22)	(17)%	
Salt Lake City Area Systems	137	135	131	2	1%	4	3%	
Permian Basin Area Systems	404	371	368	33	9%	3	1%	

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Mid-Continent Area Systems	213	214	209	(1)	%	5	2%
Manito	66	61	63	5	8%	(2)	(3)%
Rainbow	135	187	183	(52)	(28)%	4	2%
Rangeland	59	52	53	7	13%	(1)	(2)%
Refined products	102	116	100	(14)	(12)%	16	16%
Other	1,077	1,004	971	73	7%	33	3%
Tariff activities total	2,942	2,889	2,836	53	2%	53	2%
Trucking	105	97	85	8	8%	12	14%
Transporation segment total	3,047	2,986	2,921	61	2%	65	2%

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

The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIP Plans that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the Selected Items Impacting Comparability section of the table as shown within the Results of Operations-Non-GAAP

Table of Contents

Financial Measures	discussion above excludes this portion of the equity compensation expense.	See Note 10 to our	Consolidated Financial
Statements for additi	onal discussion regarding 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.

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.

The following is a discussion of items impacting transportation segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our total transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Noteworthy volume variances for 2011 compared to 2010 on our individual pipeline systems included (i) increased volumes on our Basin and Permian Basin Area Systems and certain of our Canadian pipelines driven by increased producer drilling in the surrounding regions and (ii) additional volumes of approximately 28,000 barrels per day for 2011 from the Robinson Lake pipeline acquired in connection with the Nexen acquisition in December 2010, which, in the Average Daily Volumes table above is included within Other. These favorable volume variances were partially offset by (i) decreased volumes on our Rainbow System related to downtime associated with a pipeline release detected during April 2011 (see further discussion below) as well as a third-party competitor pipeline placed into service during the third quarter of 2011 and (ii) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply and unplanned refinery downtime.

The most noteworthy favorable volume variance for 2010 compared to 2009 was the increase of volumes on our Capline pipeline system that resulted from the additional 21% undivided joint interest that we purchased in this pipeline system during December 2009.

In addition to the impact of the volumetric variances discussed above, our transportation segment results were also impacted by the following for the years ended December 31, 2011, 2010 and 2009:

- Rate Changes Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the upward or downward indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate pipelines or other negotiated rate changes. During the comparable periods discussed herein, revenues fluctuated on our FERC regulated pipelines due to the upward indexing that was effective July 1, 2009 and July 1, 2011 and the downward indexing of the FERC rate that was effective as of July 1, 2010. Revenues were further impacted by increasing tariff rates on our Canadian pipelines.
- Foreign Exchange Impact Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2011,

2010, and 2009 were \$0.99 CAD: \$1.00 USD, \$1.03 CAD: \$1.00 USD, and \$1.14 CAD: \$1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted by approximately \$12 million for 2011 compared to 2010 and by approximately \$24 million for 2010 compared to 2009 due to the appreciation of the Canadian dollar relative to the U.S. dollar.

- 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. The loss allowance revenue increased by approximately \$16 million for 2011 compared to 2010 and \$9 million for 2010 compared to 2009. These increases were primarily due to a higher average realized price per barrel during each of the comparative periods (including the impact of gains from derivative activities). The increase for the 2011 period was partially offset by lower volumes.
- Trucking Business Activity Trucking revenues, net of costs, increased by approximately \$10 million for 2011 compared to 2010 primarily due to increased volumes in Canada resulting from increased producer drilling and downtime on the Rainbow Pipeline. See additional discussion regarding our Rainbow Pipeline release below as well as Note 11 to our Consolidated Financial Statements. Trucking revenues, net of costs, increased by approximately \$4 million for 2010 compared to 2009 primarily due to volume increases from increased short-haul shipments and the addition of a heavy oil truck terminal at Nipisi, Alberta during December 2009, which was partially offset by higher fuel costs.

69

Table of Contents

- Rainbow Pipeline System As a result of a crude oil release that occurred in April 2011, volumes and revenues for the Rainbow Pipeline System were reduced due to pipeline downtime on a portion of the system, and expenses increased due to repair and response costs. In an unrelated development occurring shortly after the release, we experienced additional downtime and expenses related to forest fires in the same region. As a result of these incidents, for the year ended December 31, 2011, we estimate revenues were reduced by approximately \$21 million. However, such unfavorable impacts were partially offset by the benefit of increased tariff rates on the system, as discussed further above. We resumed service on the impacted segment of the pipeline on August 30, 2011. See Note 11 to our Consolidated Financial Statements for further information regarding this pipeline release.
- Acquisitions As discussed above, we acquired the Robinson Lake pipeline as part of the December 2010 Nexen acquisition. This pipeline contributed approximately \$8 million of revenue for the year ended December 31, 2011.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the impact of approximately \$11 million of environmental remediation expenses associated with the Rainbow Pipeline release. See Note 11 to our Consolidated Financial Statements for further information regarding this release. Excluding costs associated with this incident, field operating costs per barrel increased approximately 6% in 2011 to \$0.34 per barrel as compared to \$0.32 per barrel in 2010 due to general cost increases and volume mix. Field operating costs for 2009 were approximately \$0.32 per barrel.

Equity Compensation Expenses. Equity compensation expense increased during 2011 and 2010, primarily due to (i) an increase in unit price of \$10.66 and \$9.94 during 2011 and 2010, respectively, and (ii) additional awards that have been deemed probable of occurring. The increase in unit price impacts the fair value of our liability-classified awards. A majority of our equity compensation awards (including the Class B units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2011 and 2010, we determined that PAA distribution levels of \$4.35 and \$4.00 per unit, respectively, that were previously improbable, were probable of occurring. We incurred additional expense in both periods as a result of the additional awards that were deemed probable of occurring. See Note 10 to our Consolidated Financial Statements for further information regarding our equity compensation plans.

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 in 2011 compared to 2010 and in 2010 compared to 2009 is primarily due to increased spending on pipeline integrity projects as well as timing of repairs between years.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities increased for year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to earnings from our 34% interest in White Cliffs Pipeline LLC, which we acquired in September 2010.

Table of Contents

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, natural gas 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:

Storage and terminalling revenues (1)	\$ 605	i	\$ 490	\$ 362	\$ 115	23%	\$ 128	35%
Natural gas sales (2)	191				191	N/A		N/A
Storage related costs (natural gas								
related)	(22	2)	(23)	(5)	1	4%	(18)	(360)%
Natural gas costs (2)	(183	3)			(183)	N/A		N/A
Field operating costs (excluding								
equity compensation expense)	(165	i)	(140)	(120)	(25)	(18)%	(20)	(17)%
Equity compensation expense -								
operations (3)	(2	2)	(2)	(1)		%	(1)	(100)%
Segment general and administrative								
expenses (excluding equity								
compensation expense)	(47	')	(39)	(26)	(8)	(21)%	(13)	(50)%
Equity compensation expense -								
general and administrative (3)	(19))	(16)	(10)	(3)	(19)%	(6)	(60)%
Equity earnings in unconsolidated								
entities				8		%	(8)	(100)%
Segment profit	\$ 358		\$ 270	\$ 208	\$ 88		62	30%
Maintenance capital	\$ 22		\$ 17	\$ 16	\$ (5)	` /	\$ (1)	(6)%
Segment profit per barrel	\$ 0.36)	\$ 0.32	\$ 0.29	\$ 0.04	13%	\$ 0.03	10%

Crude oil, refined products and LPG storage (average monthly							
capacity in millions of barrels)	70	61	56	9	15%	5	9%
Natural gas storage (average monthly capacity in billions of							
cubic feet)	71	47	26	24	51%	21	81%
LPG processing (average throughput in thousands of							
barrels per day)	14	14	15		%	(1)	(7)%
Facilities segment total (average monthly capacity in millions of							
barrels)	82	70	61	12	17%	9	15%

(1)	Includes intersegment amounts.
(2) was established in 201	Natural gas sales and costs are attributable to the activities performed by PNG s commercial optimization group, which 0.
only and have no impa the table as shown in the	The equity compensation expense presented in the reconciliation to segment profit above includes the portion of the xpense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash act on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation
(4) divided by the number	Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets of months in the period.
	Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity at for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in processing volumes multiplied by the number of days in the year and divided by the number of months in the year.
	71

Table of Contents

The following is a discussion of items impacting facilities segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues, less storage related costs and natural gas purchases, and volumes increased year-over-year for each comparative year presented. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

• PNG Acquisition and Expansion Projects Revenues and volumes for 2011 compared to 2010 were favorably impacted by PNG s completion of the Southern Pines Acquisition, which closed on February 9, 2011. This acquisition contributed approximately \$37 million of additional revenues, net of storage related costs, for 2011. Additionally, revenues and volumes for 2011 were further favorably impacted by the expansion of PNG s working gas capacity at the Pine Prairie facility.

Revenues and volumes for 2010 compared to 2009 were impacted by the PNGS Acquisition, which closed during the third quarter of 2009. This acquisition and ongoing expansion activities at PNG contributed approximately \$58 million of additional net revenue and approximately 22 billion cubic feet (Bcf) of additional natural gas storage capacity for the year ended December 31, 2010. This net revenue amount includes the applicable storage related costs that are primarily due to increased volume of leased assets. Revenues were also favorably impacted by the acquisition of a natural gas processing business, which closed during the second quarter of 2009. This acquisition contributed approximately \$9 million in additional revenue for the year ended December 31, 2010.

- Other Major Expansion Projects Expansion projects that were completed in phases throughout recent years also favorably impacted revenues and volumes. These expansion projects were completed at some of our major terminal locations, and we estimate that such projects increased our revenues by approximately \$28 million on a combined basis for the year ended December 31, 2011 compared to the year ended December 31, 2010 and by a combined \$14 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. Additions and expansions at our Cushing, Patoka and Wichita Falls facilities comprised the majority of the 9 million barrel increase in total crude oil, refined products and LPG storage average monthly capacity in 2011 as compared to 2010, while additions and expansions at our Cushing, Patoka and St. James facilities accounted for the majority of the 5 million barrel increase in 2010 as compared to 2009.
- Other Revenues for all comparative periods also increased as a result of general escalations on existing leases.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) in general remained relatively constant on a per barrel basis during the comparative periods presented. The absolute increase in costs during each comparable period is consistent with the overall growth of the segment through (i) expansion projects at some of our major terminal and storage locations and (ii) acquisitions such as the Southern Pines, PNGS and natural gas processing business acquisitions discussed above.

Equity Earnings in Unconsolidated Entities. In the September 2009 PNGS Acquisition, we acquired the remaining 50% of PAA/Vulcan. As a result, we no longer have interests in unconsolidated entities associated with our facilities segment. See Note 3 to our Consolidated Financial Statements for additional discussion regarding this acquisition.

Maintenance Capital. The increase in maintenance capital in 2011 compared to 2010 is primarily due to increased integrity spending and is impacted by timing between years for various equipment replacements and repairs.

Table of Contents

Supply and Logistics Segment

Our revenues from supply and logistics 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. 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 (i) increases or decreases in our supply and logistics segment volumes (which consist of lease gathered crude oil purchase volumes, LPG sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) 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 combination of our lease gathered business and our risk management activities provides a balance that provides general 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 supply and logistics segment for the periods indicated:

Revenues	\$ 33,068	\$ 24,990	\$ 17,759	\$ 8,078	32%	\$ 7,231	41%
Purchases and related costs (2)	(31,984)	(24,448)	(17,141)	(7,536)	(31)%	(7,307)	(43)%
Field operating costs (excluding							
equity compensation expense)	(314)	(195)	(183)	(119)	(61)%	(12)	(7)%
Equity compensation expense -							
operations (3)	(2)	(3)	(1)	1	33%	(2)	(200)%
Segment general and administrative							
expenses (excluding equity							
compensation expense)	(86)	(75)	(67)	(11)	(15)%	(8)	(12)%
Equity compensation expense -							
general and administrative (3)	(35)	(29)	(22)	(6)	(21)%	(7)	(32)%
Segment profit	\$ 647	\$ 240	\$ 345	\$ 407	170%	\$ (105)	(30)%
Maintenance capital	\$ 12	\$ 9	\$ 8	\$ (3)	(33)%	\$ (1)	(13)%
Segment profit per barrel	\$ 2.05	\$ 0.84	\$ 1.22	\$ 1.21	144%	\$ (0.38)	(31)%

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Crude oil lease gathering							
purchases	742	620	612	122	20%	8	1%
Waterborne cargos	21	68	55	(47)	(69)%	13	24%

⁽¹⁾ Revenues and costs include intersegment amounts.

	rchases and related costs include interest expense (related to hedged crude oil inventory purchases) of approximately and \$11 million for the years ended December 31, 2011, 2010, and 2009, respectively.
equity compensation exper only and have no impact of the table as shown in the	e equity compensation expense presented in the reconciliation to segment profit above includes the portion of the nse represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity see Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation
(4) Cal	lculated based on crude oil lease gathering purchased volumes, LPG sales volumes and waterborne cargo volumes.
barrel, and \$33 to \$82 per to the same pricing indices the margins related to those	Exchange (NYMEX) benchmark price of crude oil ranged from approximately \$75 to \$115 per barrel, \$64 to \$92 per barrel during 2011, 2010, and 2009, respectively. Because the commodities that we buy and sell are generally indexed is for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, we sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our creased for all periods presented, resulting from higher commodity prices and increases in volumes in the comparative
	73

Table of Contents

Generally, we expect a base level of earnings from our supply and logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. A contango market is favorable to our commercial strategies that are associated with storage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market can have a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in a backwardated market, there is little incentive to store crude oil as current prices are above future delivery prices. Our supply and logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our LPG marketing operations are weather-sensitive, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on financial performance.

The following is a discussion of items impacting supply and logistics segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes

2010. One of the principal drivers of this increase was the impact of higher volumes due to increased production related to the active development of crude oil and liquids-rich resource plays. The increase in volumes was primarily a result of increased drilling activities in the Bakken, Eagle Ford Shale, West Texas, Western Oklahoma and Texas Panhandle producing regions. Volumes also increased as a result of our December 2010 Nexen acquisition, which is primarily associated with the Bakken resource play. Another principal driver of our results was increased margins related to production volumes exceeding existing pipeline takeaway capacity in certain regions and the associated logistics challenges. As the infrastructure in these areas continues to be developed, we may not experience the same opportunities for enhanced margins that we have seen over the past year. We believe the fundamentals of our business remain strong; however, a normalization of margins may occur as the logistics challenges are addressed.

In addition, net revenues associated with our non-lease gathering activities increased for 2011 compared to 2010 as a result of (i) a more favorable market structure, (ii) more favorable crude oil quality differentials experienced in certain regions in 2011 and (iii) our mark-to-market valuation of our derivatives, as discussed further below. However, waterborne cargo volumes decreased over the 2011 period, which is primarily reflective of the increased domestic production.

2010 compared to 2009. Revenues, net of purchases and related costs, decreased by approximately \$76 million or 12% in 2010 compared to 2009 despite our relatively consistent volumetric activity primarily due to (i) decreased LPG margins and (ii) our derivative activities (as shown in the table below). LPG margins for 2010 were negatively impacted by lower demand, while 2009 margins were higher than expected due to the liquidation of lower valued inventory following a write-down of inventory values during 2008. The 2010 period was also unfavorably impacted compared to 2009 due to (i) a less favorable market structure and (ii) less favorable crude oil quality differentials; however, these unfavorable variances were partially offset by improved margins within our lease gathering activities.

Impact from derivative activities. The impact of the mark-to-market valuation of our derivative activities on net revenues was as follows (in millions):

			r the Ti Inded D		Variance				
	2	2011		2010	2009	201	11-2010		2010-2009
Gains/(losses) from derivative									
activities(1)	\$	62	\$	(17)	\$ 38	\$	79	\$	(55)

⁽¹⁾ Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased year-over-year for each of the comparative periods primarily due to increased use of third-party contractors to truck lease gathered volumes, particularly in the Rockies, due to the Nexen acquisition completed in the fourth quarter of 2010.

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Equity Compensation Expense. Equity compensation expense increased for the comparative periods presented. See a discussion regarding such
increases within the Transportation Segment above. Also, see Note 10 to our Consolidated Financial Statements for additional information on
our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and Amortization. Depreciation and amortization expense was \$249 million for the year ended December 31, 2011 compared to \$256 million and \$236 million for the years ended December 31, 2010 and 2009, respectively. Included within 2011 and 2010 depreciation expense are reductions resulting from extensions of the depreciable lives of several of our crude oil and other storage facilities and pipeline systems. The extension of depreciable lives is based on an internal review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and technology. The reductions of depreciation expense associated with the extensions of depreciable lives were \$23 million in 2010 and \$60 million (incrementally by \$37 million as compared to the prior year) in 2011. This decrease was offset by an increased amount of assets resulting from our acquisition activities, including Southern Pines and Nexen in 2011 and PNGS and a natural gas processing business in 2010 as well as various internal growth projects in both years.

Included in depreciation expense for the years ended December 31, 2011, 2010 and 2009 are net losses of approximately \$11 million, \$13 million and \$1 million, respectively, recognized upon disposition of certain assets and impairments for assets taken out of service. Amortization of debt issue costs was \$7 million, \$7 million and \$6 million in 2011, 2010 and 2009, respectively.

Interest Expense

Interest expense was \$253 million for the year ended December 31, 2011, compared to \$248 million and \$224 million for the years ended December 31, 2010 and 2009, respectively. Interest expense is primarily impacted by:

- our weighted 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

interest capitalized on capital projects.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2011 and 2010 (in millions, except for percentages):

	\$	Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2009	\$ 224	0.3%	6.0%
Impact of retirement of senior notes (2)(3)	(21)		