ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
March 01, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2010

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware	76-0568219
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana Street, 10th Floor, Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

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

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

Securities to be 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 þ 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 þ

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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 þ 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. þ

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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	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 þ

The aggregate market value of Enterprise Products Partners L.P.'s ("EPD") common units held by non-affiliates at June 30, 2010 was approximately $15.7 billion based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange. This figure excludes common units beneficially owned by certain affiliates, including the estate of Dan L. Duncan. There were 843,674,372 common units of EPD and 4,520,431 Class B units (which generally vote together with the common units) outstanding at February 1, 2011.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

1

Table of Contents

SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" a intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business.

Enterprise is managed by its general partner, which is currently Enterprise Products Holdings LLC ("Enterprise GP") as a result of the Holdings Merger (see below). Enterprise GP was formerly named EPE Holdings, LLC ("EPE Holdings"), which was the general partner of Enterprise GP Holdings L.P. ("Enterprise GP Holdings" or "Holdings"). Enterprise GP is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company. Enterprise's former general partner was Enterprise Products GP, LLC ("EPGP").

On September 3, 2010, Holdings, Enterprise, Enterprise GP, EPGP and Enterprise ETE LLC ("MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into MergerCo and related transactions were completed, with MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is a director of Enterprise GP and one of three managers of Dan Duncan LLC.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within 90 days of the vacancy's occurrence, the Chief Executive Officer ("CEO") of our general partner, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously.

Ms. Williams is currently the Duncan Voting Trustee.

Table of Contents

The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. For all purposes whatsoever, the DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take part in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and, subject to the provisions of the DD LLC Voting Trust Agreement, to receive distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, EPO, Duncan Energy Partners (as defined below), DEP GP (as defined below), EPGP, Holdings and Enterprise GP were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO, Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and CEO of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). We own noncontrolling interests in Energy Transfer Equity, which we account for using the equity method of accounting.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2010 ("annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe, similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Table of Contents

PART I

Items 1 and 2. Business and Properties.

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids, or NGLs, crude oil, refined products and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. Our principal executive offices are located at 1100 Louisiana Street, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website address is www.epplp.com.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 100% by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. Our general partner is a wholly owned subsidiary of Dan Duncan LLC.

As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
Lbs	= pounds
MBPD	= thousand barrels per day
MBbls	= thousand barrels
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
TBtus	= trillion British thermal units

Business Strategy

We operate an integrated network of midstream energy assets. Our business strategies are to:

§ capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities including in the Rocky Mountains and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale and Eagle Ford Shale producing regions;

§ capitalize on expected demand growth for natural gas, NGLs, crude oil and petrochemical and refined products;

§ maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

§ enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and

§ share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth capital projects or purchase the projects' end products.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future.

Table of Contents

Offer to Acquire Duncan Energy Partners

On February 22, 2011, Enterprise submitted a proposal to the Audit, Conflicts and Governance Committee of the Board of Directors of DEP GP to purchase all of Duncan Energy Partners' outstanding publicly-held common units through a unit-for-unit exchange. Subject to negotiation and execution of a definitive agreement, Enterprise would offer 0.9545 of its common units for each outstanding publicly-held Duncan Energy Partners' common unit as part of a transaction that would be structured as a merger between Duncan Energy Partners and a wholly owned subsidiary of Enterprise. The proposed exchange ratio represents a value of $42.00 per common unit, or a premium of approximately 30%, based on the 10-day average closing price of Duncan Energy Partners' common units on February 18, 2011. If the proposed merger is approved, Enterprise will file a registration statement, which will include a proxy statement of Duncan Energy Partners and other materials, with the SEC.

Holdings Merger

On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with MergerCo and related transactions were completed, with MergerCo surviving such merger. At the effective time of the Holdings Merger, Enterprise GP (which was the general partner of Holdings prior to consummation of the Holdings Merger) succeeded as Enterprise's general partner, and each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive Enterprise common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. Enterprise issued an aggregate of 208,813,454 of its common units (net of 23 fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of its common units previously owned by Holdings.

In connection with the Holdings Merger, Enterprise's partnership agreement was amended and restated to effect the cancellation of its general partner's 2% economic general partner interest and its incentive distribution rights in Enterprise. In addition, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise on an initial amount of 30,610,000 of Enterprise's common units (the "Designated Units") for a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions to be paid during the following periods, if any: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

For information regarding other developments during 2010, see "Significant Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1 and 2 discussion.

Basis of Presentation

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger was accounted for as an equity transaction, and no gain or loss was recognized, in accordance with Accounting Standards Codification ("ASC") 810-10-45, Consolidation – Overall – Changes in Parent's Ownership Interest in a Subsidiary. The Holdings Merger results in Enterprise GP Holdings L.P. being considered the surviving consolidated entity for accounting purposes, while Enterprise Products Partners L.P. is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE: EPE) electronically filed its annual and quarterly

Table of Contents

consolidated financial statements with the U.S. Securities and Exchange Commission. You can access this information at www.sec.gov.

See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding the basis of presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 1 and 2 discussion.

Significant Growth Capital Projects

Eagle Ford Shale. We continue to expand our midstream asset capabilities in the Eagle Ford Shale supply basin in South Texas and recently announced new commercial agreements with several major producers including EOG Resources, Inc., Anadarko Petroleum Corporation ("Anadarko"), Pioneer Natural Resources USA, Inc., Petrohawk Energy Corporation and Chesapeake Energy Corporation. In June 2010, we announced several new natural gas, NGL and crude oil infrastructure construction projects to accommodate growing production volumes from the Eagle Ford Shale. We plan to install approximately 360 miles of pipelines, build a new natural gas processing facility in South Texas and construct a 75 MBPD NGL fractionator at our Mont Belvieu complex. Following completion of these construction projects, which is expected in mid-2012, we will have the capability to gather, transport and process almost 2.1 Bcf/d of natural gas and produce more than 150 MBPD of NGLs from South Texas and the Eagle Ford Shale.

The planned construction projects include an expansion of our Eagle Ford rich natural gas mainline that will involve adding three additional pipeline segments totaling 168 miles. Upon completion, the rich gas mainline system and associated laterals will consist of approximately 300 miles of pipelines representing gathering and transportation capacity of more than 600 MMcf/d. The east end of the Eagle Ford mainline will terminate at a new cryogenic natural gas processing facility we plan to build that will produce in excess of 60 MBPD of mixed NGLs. Takeaway capacity for residue gas from the new processing facility will be provided by a combination of our existing pipeline infrastructure and construction of additional natural gas pipelines, including a new 64-mile, 36-inch diameter pipeline that terminates at our Wilson natural gas storage facility. An expansion project to provide an incremental 5 Bcf of natural gas storage capacity adjacent to our Wilson facility is currently underway.

Transportation of mixed NGLs from our new processing facility to our Mont Belvieu complex will be accomplished by expanding our infrastructure, highlighted by the planned construction of a new 127-mile, 16-inch diameter NGL pipeline. This new pipeline will have an initial transportation capacity of more than 80 MBPD, and will be readily expandable to over 210 MBPD if needed. To accommodate expected volumes from the Eagle Ford Shale and other producing regions, we plan to construct a fifth NGL fractionator with a design capacity of 75 MBPD at our Mont Belvieu complex. The addition of this fifth unit will increase NGL fractionation capacity at our Mont Belvieu complex to approximately 380 MBPD.

In addition to the natural gas and NGL projects described above, we are also constructing a 140-mile expansion of our South Texas System to serve crude oil producers in the Eagle Ford Shale basin. This pipeline expansion will facilitate crude oil deliveries to the Cushing and Houston markets and is expected to be completed in the fourth quarter of 2011. We are also constructing a new crude oil terminal, which will be strategically located southeast of Houston, Texas close to two large-diameter crude oil distribution pipelines. The new crude oil terminal, which is expected to begin service in mid-2012, will provide access to major refiners in Texas City, Texas as well as other installations in Pasadena/Deer Park and Baytown, Texas and along the Houston Ship Channel via our Seaway Crude Pipeline System.

In the aggregate, the estimated cost of our Eagle Ford expansion projects is approximately $2.7 billion (including capitalized interest), which we expect to be incurred from 2010 to 2012.

Haynesville Extension. In October 2009, we announced plans to extend our Acadian Gas System into the rapidly growing Haynesville Shale supply basin in northwest Louisiana. Our 270-mile Haynesville Extension pipeline will have transportation capacity of up to 1.8 Bcf/d of natural gas and will extend from our existing Acadian Gas System to the Haynesville, Louisiana production region. The pipeline is also

Table of Contents

planned to interconnect with interstate pipelines in central and southern Louisiana. The pipeline is expected to be completed in September 2011.

The total budgeted cost of the Haynesville Extension is approximately $1.56 billion (including capitalized interest). In June 2010, Duncan Energy Partners agreed to fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures. In order to fund its capital spending requirements under the Haynesville Extension project, Duncan Energy Partners entered into new long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

For additional information regarding our capital project expenditures, see "Liquidity and Capital Resources Capital Spending" included under Item 7 of this annual report.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have six reportable business segments:

§ NGL Pipelines & Services;

§ Onshore Natural Gas Pipelines & Services;

§ Onshore Crude Oil Pipelines & Services;

§ Offshore Pipelines & Services;

§ Petrochemical & Refined Products Services; and

§ Other Investments.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, properties owned, seasonality and competition. Our results of operations and financial condition are subject to a variety of risks. For information regarding our risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1 and 2.

Our consolidated revenues are derived from a wide customer base. During 2010 and 2009, our largest non-affiliated customer was Shell Oil Company and its affiliates ("Shell"), which accounted for 9.4% and 9.8% of our consolidated revenues, respectively. During 2008, our largest non-affiliated customer was Valero Energy Corporation and its affiliates ("Valero"), which accounted for 11.2% of our consolidated revenues.

For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report. In addition, certain of our operations entail the use of derivative instruments. For information regarding our use of commodity derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Financial Information by Business Segment

For detailed financial information regarding our business segments, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our: (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 16,900 miles; (iii) NGL and related product storage and terminal facilities with approximately 160 MMBbls of working storage capacity; and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to produce isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, and is used in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 25 processing plants located across Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of NGLs. This rich natural gas in its raw form is usually not acceptable for transportation in the nation's natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove NGLs from the natural gas stream, which enables the natural gas to meet pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of a natural gas stream. After extraction by the processing plants, we typically transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to a percentage of the mixed NGLs we extract and generally bears the cost of natural gas associated with shrinkage and plant fuel. The value of natural gas lost as a result of NGL extraction (i.e., shrinkage) and consumed as plant fuel is

Table of Contents

referred to as plant thermal reduction ("PTR"). Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing natural gas at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs in which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our keepwhole and margin-band gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts typically contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments (e.g., forward NGL sales contracts).

Our NGL marketing activities generate revenues from the sale and delivery of NGLs we take title to through our processing activities (i.e., our equity NGL production) and open market and contract purchases from third parties. These sales contracts may also include forward product sales contracts. In general, sales prices referenced in the contracts utilized within our NGL marketing activities are market-based and may include pricing differentials for such factors as delivery location. The majority of our consolidated revenues and costs and expenses are generated from marketing activities, including those associated with NGLs. Changes in our consolidated revenues and operating costs and expenses period-to-period are explained in part by changes in market prices for the products we sell. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the sales prices charged to customers. The volume of products sold may fluctuate from period-to-period depending on market conditions, volumes produced and opportunities, which may be influenced by current and forward market prices for purity NGL products and our hedging activities.

Our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. Our inventories of ethane, propane and normal butane are typically at higher levels from March through November since these products are normally in higher demand and at higher price levels during the winter months. Isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year. Generally, our inventory cycle begins in late-February to mid-March (the seasonal low point), building through September, and remaining level until early December before being drawn down through winter until the seasonal low is reached again.

For additional information regarding our inventories and consolidated segment revenues and expenses, see Notes 7 and 14, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

NGL pipelines, storage facilities and import/export terminals. Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect purity NGL products to and from fractionation plants, petrochemical plants, export facilities and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Excluding inventories held in connection with our marketing activities, we typically do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. However, we occasionally act as shipper for certain volumes being transported.

Our NGL and related product storage facilities are integral parts of our operations used for the storage of products owned by us and our customers. In general, our underground salt dome storage caverns (or wells) are used to store mixed NGLs and purity NGL, petrochemical and refined products. We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. The customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage. Accordingly, the profitability of our storage operations is dependent upon the level of storage capacity reserved by customers, the volume of product delivered into and withdrawn from the underground caverns and the level of throughput fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas and an NGL terminal in Providence, Rhode Island with ship unloading capabilities. Our NGL import facility is primarily used to offload volumes for delivery to our storage and fractionation facilities located in Mont Belvieu, Texas. Our NGL export facility is used for loading refrigerated marine tankers for customers. Revenues from our terminal services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments if terminaling contracts are cancelled. Accordingly, the profitability of our NGL terminal activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in 11 NGL fractionation facilities located in Texas, Louisiana, Colorado and Ohio. NGL fractionators separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the United States are domestic natural gas processing plants and crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck to NGL fractionation facilities.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed at our NGL fractionation facilities by joint owners and third-party customers.

Our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities. We typically earn revenues from NGL fractionation under fee-based arrangements. These fees (usually stated in cents per gallon) are contractually subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility in

Table of Contents

Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

Seasonality. Our natural gas processing and NGL fractionation operations typically exhibit little to no seasonal variation. NGL pipeline transportation volumes are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending into motor gasoline). With respect to our NGL and related product storage facilities, we usually experience an increase in demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn down for heating needs. Likewise, the revenues we recognize from NGL marketing activities are predicated on the overall demand for such products, which may fluctuate due to seasonal needs for gasoline blending feedstocks, heating requirements and similar factors. In general, our import volumes peak during the spring and summer months and our export volumes are typically at their highest levels during the winter months. Lastly, our facilities located along the Gulf Coast of the United States may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our natural gas processing business activities and related NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, financial institutions with trading platforms and independent processors. Each of our marketing competitors has varying levels of financial and personnel resources, and competition generally revolves around price, quality of customer service and proximity to customers and other market hubs. In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate pipeline companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and quality of customer service.

Our primary competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections provided and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading throughput capacity.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL fractionator to receive a customer's mixed NGLs and store and distribute its purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Table of Contents

Properties. The following table summarizes the significant natural gas processing assets included in our NGL Pipelines & Services business segment at February 1, 2011.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Meeker	Colorado	100%	1.70	1.70
Pioneer	Wyoming	100%	1.35	1.35
Toca	Louisiana	67.9%	0.70	1.10
Chaco	New Mexico	100%	0.65	0.65
North Terrebonne	Louisiana	64.2%	0.73	1.30
Calumet	Louisiana	35.4%	0.57	1.60
Neptune	Louisiana	66%	0.43	0.65
Pascagoula	Mississippi	40%	0.40	1.50
Yscloskey	Louisiana	13.6%	0.26	1.85
Thompsonville	Texas	100%	0.33	0.33
Shoup	Texas	100%	0.29	0.29
Gilmore	Texas	100%	0.25	0.25
Armstrong	Texas	100%	0.25	0.25
Others (11 facilities) (2)	Texas, New Mexico, Louisiana	Various (3)	1.27	2.93
Total processing capacities			9.18	15.75

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) Other natural gas processing facilities include our Venice, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin, Carlsbad and Chaparral facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").
(3) Our ownership in these facilities ranges from 13.1% to 100%.

Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Meeker, Pioneer, Toca, Chaco, North Terrebonne, Calumet, Neptune, Burns Point, Carlsbad and Chaparral plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 51.2%, 48.3% and 52.4% during the years ended December 31, 2010, 2009 and 2008, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 350 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

Table of Contents

The following table summarizes the significant NGL pipelines and related storage assets included in our NGL Pipelines & Services business segment at February 1, 2011.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Usable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	8,068	
Seminole Pipeline	Texas	90% (1)	1,373	
South Texas NGL System	Texas	100% (2)	1,482	
Dixie Pipeline	South and Southeastern U.S.	100%	1,306	
Chaparral NGL System (3)	Texas, New Mexico	100%	1,010	
Louisiana Pipeline System	Louisiana	100%	948	
Skelly-Belvieu Pipeline	Texas	50% (4)	572	
Promix NGL Gathering System	Louisiana	50% (5)	368	
Houston Ship Channel	Texas	100%	298	
Rio Grande Pipeline	Texas	70% (6)	249	
Lou-Tex NGL Pipeline	Texas, Louisiana	100%	205	
Others (9 systems) (7)	Various	Various	1,001	
Total miles			16,880	
NGL and related product storage capacity by state:				
Texas (8)				120.7
Louisiana				13.5
Kansas				8.4
Mississippi				7.8
Others (9)				9.6
Total working capacity (10)				160.0

(1) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company ("Seminole").
(2) The ownership interest presented reflects consolidated ownership of these systems by EPO (34%) and Duncan Energy Partners (66%).
(3) The Chaparral NGL System includes the 180-mile Quanah Pipeline, which begins in Sutton County, Texas, and connects to the Chaparral Pipeline near Midland, Texas.
(4) Our ownership interest in this pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu").
(5) Our ownership interest in this pipeline system is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(6) We hold a 70% interest in this system through a majority owned subsidiary, Rio Grande Pipeline Company ("Rio Grande").
(7) Includes our Tri-States, Belle Rose, Wilprise, Chunchula, Bay Area and South Dean pipelines located in the coastal regions of Alabama, Louisiana, Mississippi and Texas; Port Arthur, Wilcox and Panola pipelines located in East Texas; and our Meeker pipeline in Colorado.
(8) The amount shown for Texas includes 34 underground NGL, petrochemical and refined products storage caverns with an aggregate working capacity of approximately 100 MMBbls that are owned by EPO (34%) and Duncan Energy

Partners (66%). These 34 caverns are located in Mont Belvieu, Texas.
(9) Includes storage capacity at our facilities in Alabama, Arizona, California, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina and Wisconsin.
(10) Our underground storage caverns and above ground storage tanks have an aggregate 160 MMBbls of total working storage capacity, which includes 23.2 MMBbls held under long-term operating leases. The leased facilities are located in Indiana, Kansas, Louisiana and Texas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products being shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,207 MBPD, 2,099 MBPD and 1,948 MBPD during the years ended December 31, 2010, 2009 and 2008, respectively.

Table of Contents

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Tri-States pipeline.

§ The Mid-America Pipeline System is a regulated NGL pipeline system consisting of three primary segments: the 3,021-mile Rocky Mountain pipeline, the 2,769-mile Conway North pipeline and the 2,278-mile Conway South pipeline. This system is present in 13 states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline connects the Conway hub with Kansas refineries and provides birectional transportation of NGLs between Conway, Kansas and the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. This system includes 14 unregulated propane terminals.

During 2010, approximately 51% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants. The remaining volumes consisted of purity NGL products originating from NGL fractionators located in Kansas, Oklahoma and Texas, as well as deliveries from Canada.

§ The Seminole Pipeline is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of West Texas to markets in southeast Texas including our NGL fractionation facility in Mont Belvieu, Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

§ The South Texas NGL System is a network of NGL gathering and transportation pipelines located in South Texas. The system gathers and transports mixed NGLs from our South Texas natural gas processing plants to our South Texas NGL fractionation facilities. In turn, the system transports NGLs from our South Texas NGL fractionation facilities to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines. The South Texas NGL System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas.

§ The Dixie Pipeline is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern United States and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. This system includes eight unregulated propane terminals and operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

§ The Chaparral NGL System transports NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 830-mile regulated Chaparral pipeline and the 180-mile unregulated Quanah pipeline.

§ The Louisiana Pipeline System is a network of NGL pipelines located in southern Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical companies located along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. Originating from a central point in Henry, Louisiana, pipelines extend westward to Lake Charles, northward to an interconnect with the Dixie Pipeline at Breaux Bridge, and eastward to Napoleonville, Louisiana, where our Promix NGL fractionation and storage facilities are located.

Table of Contents

- § The Skelly-Belvieu Pipeline is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. We became operator of this pipeline in January 2011.

- § The Promix NGL Gathering System gathers mixed NGLs from natural gas processing plants in southern Louisiana for delivery to our Promix NGL fractionator.

- § The Houston Ship Channel pipeline system connects our Mont Belvieu, Texas facilities with our Houston Ship Channel import/export terminals and various third-party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

- § The Rio Grande Pipeline is a regulated pipeline originating near Odessa, Texas that transports mixed NGLs to a pipeline interconnect at the Mexican border south of El Paso, Texas.

- § The Lou-Tex NGL Pipeline system transports NGLs and refinery grade propylene between the Louisiana and Texas markets.

Our NGL and related product storage and terminal facilities are integral components of our midstream energy infrastructure. We operate these storage and terminal facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and a facility in Kansas that are operated for us by a third-party.

Our largest underground storage facility is located in Mont Belvieu, Texas and is owned 66% by Duncan Energy Partners and 34% by EPO. This storage facility consists of 34 underground NGL, petrochemical and refined product salt dome storage caverns with an aggregate working storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical and refined products for industrial customers located along the upper Texas Gulf Coast. During 2010, Duncan Energy Partners elected to participate with us on a cavern conversion project, which consists of converting two storage caverns in Mont Belvieu, Texas from NGL to refined products storage service. Conversion of one of the caverns was completed in November 2010. We are currently evaluating the timing for converting the second cavern.

On February 8, 2011, a fire occurred at our Mont Belvieu, Texas storage complex (at the West Storage facility). The incident resulted in one fatality. The West Storage Facility consists of 10 underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls and an above-ground brine pit with a brine capacity of approximately 2 MMBbls. Operationally, we have focused on returning our Mont Belvieu facilities to as close to the same capabilities as we had prior to the event. We are changing our storage configuration to enable us to recover our receipt and delivery capabilities by utilizing our North and East Storage facilities. We continue to work with authorities to determine the cause of the event. Our insurance deductible for property damage events such as this is $5 million per occurrence. At this time, due to the recent nature of this incident, we are not able to estimate any additional losses related to this event other than the property damage insurance deductible.

Table of Contents

The following table summarizes the significant NGL fractionation assets included in our NGL Pipelines & Services business segment at February 1, 2011.

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	75% (2)	253	305
Shoup and Armstrong	Texas	100% (3)	97	97
Hobbs	Texas	100%	75	75
Norco	Louisiana	100%	75	75
Promix	Louisiana	50% (4)	73	145
BRF	Louisiana	32.2% (5)	19	60
Tebone	Louisiana	56.4% (2)	12	30
Other (6)	Colorado, Ohio	100%	15	15
Total plant capacities			619	802

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) Ownership interests presented reflect direct consolidated interests in each facility.
(3) The ownership interest presented reflects consolidated ownership of these plants by EPO (34%) and Duncan Energy Partners (66%).
(4) Our ownership interest in this facility is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(6) Consists of two NGL fractionation facilities located in northeast Colorado and a fractionation facility located near Todhunter, Ohio.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities, with the exception of our two Colorado fractionators.

§ Our Mont Belvieu NGL fractionation facility is located in Mont Belvieu, Texas, which is a key hub of the NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, East Texas and the Gulf Coast.

In November 2010, we commenced operations on a fourth 75 MBPD NGL fractionator at our Mont Belvieu facility that provides us with additional capacity to process growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale supply basin in South Texas. This project increased our gross NGL fractionation capacity at Mont Belvieu to approximately 305 MBPD. To accommodate expected volumes from the Eagle Ford Shale and other producing regions, we plan to construct a fifth NGL fractionator with a capacity of 75

MBPD. This project is expected to be completed by January 2012.

§ Our Shoup and Armstrong fractionators process mixed NGLs supplied by our South Texas natural gas processing plants. Purity NGL products from the Shoup and Armstrong fractionators are transported to local markets in the Corpus Christi area and also to Mont Belvieu, Texas using our South Texas NGL Pipeline System.

In May 2010, we and Duncan Energy Partners announced our plans to expand our Shoup and Armstrong fractionation facilities to provide us with the ability to accommodate increased NGL volumes associated with increased natural gas production from the Eagle Ford natural gas supply basin. In June 2010, we completed the modifications to our Shoup facility, which increased its NGL fractionation capacity to 77 MBPD. In January 2011, we completed modifications to

Table of Contents

infrastructure at the Armstrong facility, which increased its NGL fractionation capacity to 20 MBPD.

- § Our Hobbs NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical plants and refineries in West Texas, New Mexico, California and northern Mexico. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

- § Our Norco NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including from our Yscloskey, Pascagoula, Venice and Toca facilities.

- § The Promix NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including from our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the Promix NGL Gathering System (described previously), Promix owns five NGL storage caverns and a barge loading facility that are integral to its operations.

- § The BRF facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 90.7%, 88.8% and 83.6% during the years ended December 31, 2010, 2009 and 2008, respectively. These rates reflect the periods in which we owned an interest in such facilities or, for recently constructed facilities, since the dates such assets were placed into service.

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP. Our import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. In addition to these facilities, we own a barge dock also located on the Houston Ship Channel that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. We also own an NGL terminal in Providence, Rhode Island that includes 0.4 MMBbls of refrigerated tank storage capacity and ship unloading capabilities at rates up to 11,800 barrels per hour. Our average combined NGL import and export volumes were 114 MBPD, 98 MBPD and 74 MBPD for the years ended December 31, 2010, 2009 and 2008, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,800 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our related natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing activities. Our onshore natural gas pipeline systems provide for the gathering and transportation of natural gas from major producing regions such as the San Juan, Barnett Shale, Permian, Piceance, Greater Green River, Haynesville and Eagle Ford supply basins in the western United States. In addition, certain of these systems receive natural gas production from the Gulf of Mexico through coastal pipeline interconnects with offshore pipelines. Our onshore natural gas pipelines receive natural gas from producers, other pipelines or shippers through

Table of Contents

system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers, or to other onshore pipelines.

Our onshore natural gas pipelines typically generate revenues from transportation agreements whereby shippers are billed a fee per unit of volume transported (typically per MMBtu) multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. In connection with our natural gas transportation services and marketing activities, intrastate natural gas pipelines (such as our Acadian Gas System) may also purchase natural gas from producers and other suppliers for transport and resale to customers such as electric utility companies, local natural gas distribution companies, industrial users and other natural gas marketing companies.

Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from third-party well-head purchases, regional natural gas processing plants and the open market. In general, sales prices referenced in the contracts utilized within our natural gas marketing activities are market-based and may include pricing differentials for such factors as delivery location. We entered the natural gas marketing business in an effort to maximize the utilization of our portfolio of natural gas pipeline and storage assets. We expect our natural gas marketing business to continue to expand in the future. The results of operations for our onshore natural gas pipelines and related marketing activities are generally dependent upon the volume of natural gas transported and/or sold, the level of firm capacity reservations made by customers and amounts charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements).

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with certain intrastate natural gas transportation contracts and our natural gas marketing activities. In addition, we purchase and resell natural gas for certain producers that use our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to fluctuations in commodity prices through transportation arrangements with shippers. For example, nearly all of the transportation revenues generated by our San Juan Gathering System are based on a percentage of a regional price index for natural gas. This index is subject to change based on a variety of factors including natural gas supply and consumer demand. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage (“Petal”) and Hattiesburg Gas Storage locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into six interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

Our natural gas storage facilities are designed to handle sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal modes of operation. The ability of underground salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond quickly in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities.

Table of Contents

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation utilities increase their output to meet residential and commercial demand for electricity used for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is used to meet residential and commercial heating requirements. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Competition. Within their market areas, our onshore natural gas pipelines compete with other natural gas pipelines on the basis of price (in terms of transportation fees), quality of customer service and operational flexibility. Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates and financial institutions with trading platforms. Competition in the natural gas marketing business is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Table of Contents

Properties. The following table summarizes the significant assets included in our Onshore Natural Gas Pipelines & Services business segment at February 1, 2011.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100% (1)	8,128	6,640	
Jonah Gathering System	Wyoming	100%	849	2,550	
Piceance Basin Gathering System	Colorado	100%	106	1,600	
White River Hub	Colorado	50% (2)	10	1,500	
San Juan Gathering System	New Mexico, Colorado	100%	6,070	1,200	
Acadian Gas System	Louisiana	Various (3)	1,041	1,149	
Val Verde Gas Gathering System	New Mexico, Colorado	100%	467	550	
Carlsbad Gathering System	Texas, New Mexico	100%	919	220	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	589	143	
State Line Gathering System (4)	Louisiana, Texas	100%	188	700	
Fairplay Gathering System (4)	Texas	100%	249	285	
Other (5 systems) (5)	Texas, Mississippi	Various (6)	754	2,015	
Total miles			19,778		
Natural gas storage facilities:					
Petal	Mississippi	100%			16.6
Hattiesburg	Mississippi	100%			2.1
Wilson	Texas	Leased (7)			6.8
Acadian	Louisiana	Leased (8)			1.3
Total gross capacity					26.8

(1) In general, our consolidated ownership of this system is 100% through interests held by EPO and Duncan Energy Partners. We own and operate a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in and lease certain segments of the Enterprise Texas pipeline system, which is a component of the Texas Intrastate System.
(2) Our ownership interest in this natural gas pipeline hub facility is held indirectly through our equity method investment in White River Hub, LLC ("White River Hub").
(3) Our ownership interest reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Amounts presented include the 49.5% equity method investment that Acadian Gas has in the 27-mile Evangeline pipeline.
(4) We acquired the State Line and Fairplay Gathering Systems in May 2010.
(5) Includes the Delmita, Big Thicket and Indian Springs gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. The Petal and Hattiesburg pipelines, which have a combined capacity in

excess of 1.6 MMcf/d, are integral components of our Petal and Hattiesburg natural gas storage operations.
(6) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary. Our 100% ownership interest in Big Thicket reflects consolidated ownership by EPO (34%) and Duncan Energy Partners (66%).
(7) We hold this facility under an operating lease that expires in January 2028.
(8) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64.2%, 64.4% and 68.7% during the years ended December 31, 2010, 2009 and 2008, respectively. Such utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where throughput capacity is reserved whether or not the shipper actually utilizes such capacity. The utilization rate for 2008 excludes the White River Hub, which commenced operations during December 2008. Our utilization rates reflect the periods in which we owned an interest in such assets or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines. With the exception of the White River Hub and certain minor segments of the Texas Intrastate System, we operate our onshore natural gas pipelines and storage facilities.

Table of Contents

§ The Texas Intrastate System gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,653-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 660-mile Waha gathering system and the 174-mile TPC Offshore gathering system. The Enterprise Texas pipeline system includes a 265-mile pipeline we lease from an affiliate of ETP. The leased Wilson natural gas storage facility located in Wharton County, Texas is an integral part of the Texas Intrastate System. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 173-mile Sherman Extension pipeline, which is part of our Enterprise Texas pipeline system, was completed in late February 2009 and is capable of transporting up to 1.2 Bcf/d of natural gas from the prolific Barnett Shale supply basin in North Texas. The Sherman Extension provides producers with connections to third-party interstate pipelines having access to markets outside of Texas. An aggregate of 1.0 Bcf/d of the Sherman Extension's throughput capacity has been contracted for by customers, including EPO, under long-term contracts.

In July 2010, we completed and placed the final segment of our Trinity River Lateral natural gas pipeline into service. The Trinity River Lateral pipeline, which is part of our Enterprise Texas pipeline system, extends approximately 42 miles from the Trinity River Basin north of Arlington, Texas to an interconnect near Justin, Texas with our Sherman Extension pipeline. The Trinity River Lateral provides producers in Tarrant and Denton Counties in North Texas with up to 1.0 Bcf/d of production takeaway capacity.

We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in the second quarter of 2011. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of usable natural gas storage capacity.

§ The Jonah Gathering System is located in the Greater Green River Basin of southwest Wyoming. This system gathers natural gas from the Jonah and Pinedale supply fields for delivery to regional natural gas processing plants, including our Pioneer plant, for ultimate delivery into major interstate pipelines.

§ The Piceance Basin Gathering System consists of the 52-mile Piceance Creek, 32-mile Great Divide and 22-mile Collbran Valley gathering systems located in the Piceance Basin of northwestern Colorado. The Piceance Creek gathering system extends from a connection with the Great Divide gathering system to our Meeker natural gas processing plant and ultimate delivery into the White River Hub and other major interstate pipelines. The Great Divide gathering system gathers natural gas from the southern portion of the Piceance Basin, including natural gas gathered on the Collbran Valley gathering system, to an interconnect with our Piceance Creek gathering system.

§ The White River Hub is a regulated interstate natural gas transportation hub facility. The White River Hub connects to six interstate natural gas pipelines in northwest Colorado and has a gross capacity of 3 Bcf/d of natural gas (1.5 Bcf/d net to our 50% ownership interest).

§ The San Juan Gathering System serves producers in the San Juan Basin of north New Mexico and southern Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas to regional processing plants, including our Chaco plant located in New Mexico for ultimate delivery into major interstate pipelines.

§ The Acadian Gas System purchases, transports, stores and resells natural gas in Louisiana. The Acadian Gas System is comprised of the 576-mile Cypress pipeline, the 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The Acadian Gas System includes a leased natural

Table of Contents

gas storage facility at Napoleonville, Louisiana that is an integral part of its pipeline operations. The Acadian Gas pipeline system links natural gas supplies from onshore Gulf Coast and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers, located primarily in the natural gas market area of the Baton Rouge – New Orleans – Mississippi River corridor.

In October 2009, we and Duncan Energy Partners announced plans to extend our Acadian Gas System into the rapidly growing Haynesville Shale supply basin in northwest Louisiana. Our 270-mile Haynesville Extension pipeline will have transportation capacity of up to 1.8 Bcf/d of natural gas and will extend from our existing Acadian Gas System to the Haynesville, Louisiana production region. The pipeline is also planned to interconnect with interstate pipelines in central and southern Louisiana. The Haynesville Extension will provide producers in the Haynesville Shale supply basin with takeaway capacity, including access to more than 150 end-use markets along the Mississippi River corridor between Baton Rouge and New Orleans, Louisiana. In addition, shippers will be able to access our Napoleonville salt dome storage cavern and have the ability to make physical deliveries into the Henry Hub and benefit from more favorable pricing points. The Haynesville Extension will also allow shippers to reach nine interstate pipeline systems. The pipeline is expected to be completed in September 2011.

§ The Val Verde Gas Gathering System gathers natural gas, including coal bed methane from the Fruitland Coal Formation in the San Juan Basin, from producing regions in northern New Mexico and southern Colorado.

§ The Carlsbad Gathering System gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery to natural gas processing plants, including our Chaparral and Carlsbad plants, as well as delivery into the El Paso Natural Gas and Transwestern pipelines.

§ The Alabama Intrastate System gathers natural gas, primarily coal bed methane, from the Black Warrior supply basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

§ The Encinal Gathering System gathers natural gas from the Olmos, Wilcox and Eagle Ford formations in South Texas for processing at our South Texas natural gas processing plants.

§ The State Line Gathering System gathers natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas. This independent gathering system will connect to our Haynesville Extension natural gas pipeline project, which is under development by Acadian Gas LLC. We acquired the State Line Gathering System and Fairplay Gathering System (see below) and related assets in May 2010 from M2 Midstream LLC ("Momentum") for approximately $1.2 billion in cash. For information regarding our acquisition of these systems, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ The Fairplay Gathering System gathers natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations in eastern Texas. This system is expected to extend our asset base through future interconnects with our Texas Intrastate System, along with supporting deliveries of NGLs into our Panola pipeline and further to our fractionation, storage and distribution complex in Mont Belvieu, Texas. We acquired the Fairplay Gathering System in May 2010.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,700 miles of onshore crude oil pipelines and 11 MMBbls of above-ground storage tank capacity. This segment also includes our crude oil marketing activities.

Table of Contents

Onshore crude oil pipelines, terminals and related marketing activities. Our onshore crude oil pipeline systems gather and transport crude oil primarily in Oklahoma, New Mexico and Texas to refineries, centralized storage terminals and connecting pipelines. Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of crude oil transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

We own crude oil terminal facilities in Cushing, Oklahoma and Midland, Texas that are used to store crude oil volumes for us and our customers. Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. The customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Lastly, we provide fee-based trade documentation services whereby we document the transfer of title for crude oil volumes transacted between buyers and sellers at our terminals. In general, the profitability of our crude oil terminaling operations is dependent upon the level of storage capacity reserved by our customers, the volume of product withdrawn from our terminals and the level of fees charged (including those charged internally, which are eliminated in the preparation of our consolidated financial statements).

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers or on the open market. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location. To limit the exposure of our crude oil marketing activities to commodity price risk, our purchases and sales of crude oil are generally contracted to occur within the same calendar month. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing business.

Seasonality. Our onshore crude oil pipelines and related activities typically exhibit little to no effects of seasonality. However, our onshore pipelines situated along the Texas Gulf Coast may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our onshore crude oil pipelines, terminals and related marketing activities compete with other crude oil pipeline companies, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent crude oil gathering and marketing companies. The onshore crude oil business can be characterized by thin operating margins and strong competition for supplies of crude oil. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Table of Contents

Properties. The following table summarizes the significant crude oil pipelines and related terminal assets included in our Onshore Crude Oil Pipelines & Services business segment at February 1, 2011.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Usable Storage Capacity (MMBbls) (1)
Crude oil pipelines:				
Seaway Crude Pipeline System	Texas, Oklahoma	50% (2)	669	3.4
Red River System	Texas, Oklahoma	100%	1,749	1.2
South Texas System	Texas	100%	1,174	1.1
West Texas System	Texas, New Mexico	100%	372	0.4
Other (4 systems) (3)	Texas, Oklahoma, New Mexico	Various	746	0.3
Total miles			4,710	
Crude oil terminals:				
Cushing terminal	Oklahoma	100%		3.1
Midland terminal	Texas	100%		1.5
Total capacity				11.0

(1)   Usable storage capacity is presented net to our ownership interest in each asset.
(2)   Our ownership interest in this pipeline system is held indirectly through our equity method investment in Seaway Crude Pipeline Company (“Seaway”).
(3)   Includes our Azelea, Mesquite and Sharon Ridge crude oil gathering systems and Basin Pipeline System. We own 100% of these assets with the exception of the Basin Pipeline System, in which we own a 13% undivided interest.

The maximum number of barrels that our crude oil pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon product composition and demand levels at various delivery points, the exact capacities of our crude oil pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 670 MBPD, 680 MBPD and 696 MBPD during the years ended December 31, 2010, 2009 and 2008, respectively.

Our crude oil marketing activities utilize a fleet of approximately 190 tractor-trailer tank trucks, the majority of which are leased from third parties. In addition, we have 17 crude oil truck terminal facilities in Texas, Oklahoma and North Dakota.

The following information highlights the general use of each of our principal crude oil pipelines and terminals, all of which we operate with the exception of the Basin Pipeline System.

§ The Seaway Crude Pipeline System is a regulated system that transports imported crude oil from Freeport, Texas to Cushing, Oklahoma and supplies refineries in the Houston, Texas area through its terminal facility at Texas City, Texas. The Seaway Crude Pipeline System also has a connection to our South Texas System that allows it to receive both onshore and offshore domestic crude oil production from the Texas Gulf Coast area for delivery to Cushing.

§ The Red River System is a regulated pipeline that transports crude oil from North Texas to southern Oklahoma for delivery to either two local refineries or pipeline interconnects for further transportation to Cushing, Oklahoma.

§ The South Texas System transports crude oil from an origination point in South Texas to the Houston, Texas area. Crude oil transported on the South Texas System is delivered either to Houston area refineries or pipeline interconnects (including those with our Seaway Crude Pipeline System) for ultimate delivery to Cushing, Oklahoma. The 140-mile expansion of our South Texas System designed to serve crude oil producers in the Eagle Ford Shale basin is expected to be completed in the fourth quarter of 2011.

§ The West Texas System connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas.

§ The Cushing and Midland terminals provide crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has 19 above-ground storage tanks with aggregate crude oil storage capacity of 3.1 MMBbls. The Midland terminal has a storage capacity of 1.5 MMBbls through the use of 12 above-ground storage tanks.

In addition, we are constructing a new crude oil terminal that will be located southeast of Houston, Texas. The new Houston terminal is expected to begin service in mid-2012 and will link crude oil production in the Eagle Ford Shale basin with the Houston-area refinery market.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment serves some of the most active drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. This segment includes approximately 1,400 miles of offshore natural gas pipelines, approximately 1,000 miles of offshore crude oil pipelines and six offshore hub platforms.

Our offshore Gulf of Mexico pipelines provide for the gathering and transportation of natural gas or crude oil. In general, revenues from our offshore pipelines are derived from fee-based agreements whereby the customer is charged a fee per unit of volume gathered or transported (typically per MMBtu of natural gas or per barrel of crude oil) multiplied by the volume delivered. These agreements tend to be long-term, often involving life-of-reserve commitments with both firm and interruptible components. In the case of our Poseidon Oil Pipeline System, we purchase crude oil from producers and shippers at a receipt point (at a fixed or index-based price less a location differential) and then sell like quantities of crude oil back to the customer at onshore Louisiana locations (at the same fixed or index-based price, as applicable). The net revenue we recognize from such arrangements is based on the location differential, which represents the fee Poseidon charges for providing transportation services.

Our offshore platforms are integral components of our pipeline operations. In general, platforms are critical components of the energy-related infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore crude oil and natural gas reserves. Platforms are used to: interconnect the offshore pipeline grid; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; conduct drilling operations during the initial development phase of an oil and natural gas property and process off-lease production. Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. For example, the producers utilizing our Independence Hub platform have agreed to pay us $54.6 million of demand fees annually through March 2012. These demand fees are in addition to commodity charges they pay us based on volumes delivered to the platform.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico that generally arise during the summer and fall months. See Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding weather-related risks and insurance matters.

Competition. Within their respective market areas, our offshore pipelines compete with other offshore pipelines primarily on the basis of fees charged, available throughput capacity, connections to

Table of Contents

downstream markets and proximity and access to existing reserves. Our competitors may have access to greater capital resources than we do, which could enable them to address business opportunities in the Gulf of Mexico more quickly than we can.

Properties. The following table summarizes the significant assets included in our Offshore Pipelines & Services business segment at February 1, 2011.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System (1)	100%	291		1,335	
Viosca Knoll Gathering System	100%	137		600	
Independence Trail	100%	134		1,000	
Green Canyon Laterals	Various (2)	73		446	
Phoenix Gathering System	100%	77		450	
Falcon Natural Gas Pipeline	100%	14		400	
Anaconda Gathering System	100%	137		300	
Manta Ray Offshore Gathering System (3)	25.7%	250		206	
Nautilus System (3)	25.7%	101		154	
Nemo Gathering System (5)	33.9%	24		102	
VESCO Gathering System (4)	13.1%	158		65	
Total miles		1,396			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline (6)	50%	374			250
Poseidon Oil Pipeline System (7)	36%	367			155
Shenzi Oil Pipeline	100%	83			230
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Constitution Oil Pipeline	100%	67			80
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		992			
Offshore hub platforms:					
Independence Hub	80%		8,000	800	N/A
Marco Polo (8)	50%		4,300	150	60
Viosca Knoll 817	100%		671	145	5
Garden Banks 72	50%		518	113	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) Based on the maximum allowable operating pressure, our HIOS pipeline system can transport up to 1,335 MMcf/d of natural gas. On January 12, 2010, we filed for FERC authority to reduce the firm certificated capacity on the HIOS pipeline system from 1,400 MMcf/d to 350 MMcf/d.
(2) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.
(3) Our ownership interest in these pipeline systems is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").

(4) Our ownership interest in this system is held indirectly through our equity method investment in VESCO.
(5) Our ownership interest in this system is held indirectly through our equity method investment in Nemo Gathering Company, LLC ("Nemo").
(6) Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(7) Our ownership interest in this system is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC. ("Poseidon").
(8) Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 23.8%, 22.3% and 22% during the years ended

Table of Contents

December 31, 2010, 2009 and 2008, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

§ The High Island Offshore System ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. In addition, this system includes the 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

§ The Viosca Knoll Gathering System transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

§ The Independence Trail natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline at a pipeline interconnect on our West Delta 68 platform. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The Green Canyon Laterals consist of 11 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

§ The Phoenix Gathering System connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

§ The Falcon Natural Gas Pipeline delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located at the Brazos Addition Block 133 platform.

§ The Anaconda Gathering System connects our Marco Polo platform and the third-party owned Constitution and Typhoon platforms to the ANR pipeline system.

§ The Manta Ray Offshore Gathering System transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

§ The Nautilus System connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant located in south Louisiana.

§ The Nemo Gathering System transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

§ The VESCO Gathering System is a regulated natural gas pipeline system associated with the Venice natural gas processing plant in south Louisiana. This gathering pipeline is an integral part of the natural gas processing operations of VESCO and is accounted for under our NGL Pipelines & Services business segment.

Table of Contents

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 29.5%, 28.7% and 20.1% during the years ended December 31, 2010, 2009 and 2008, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

§ The Cameron Highway Oil Pipeline gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This system includes two pipeline junction platforms.

§ The Poseidon Oil Pipeline System gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform.

§ The Shenzi Oil Pipeline provides gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi Oil Pipeline allows producers to access our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The Allegheny Oil Pipeline connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The Marco Polo Oil Pipeline transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

§ The Constitution Oil Pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

With respect to natural gas processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 28.5%, 39.4% and 36.5% during the years ended December 31, 2010, 2009 and 2008, respectively. With respect to crude oil processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 19.2%, 13.6% and 16.9% during the years ended December 31, 2010, 2009 and 2008, respectively. For recently constructed assets, these rates reflect the periods since the dates such assets were placed into service. In addition to our offshore hub platforms, we also own or have an ownership interest in 13 pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

The following information highlights the general use of each of our principal Gulf of Mexico offshore hub platforms. We operate these platforms with the exception of the Independence Hub and Marco Polo platforms.

§ The Independence Hub platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The Marco Polo platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located in the South Green Canyon area of the Gulf of Mexico.

§ The Viosca Knoll 817 platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

Table of Contents

§ The Garden Banks 72 platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The East Cameron 373 platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

§ The Falcon Nest platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, processes natural gas from the Falcon field.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment consists of (i) propylene fractionation plants, pipelines and related marketing activities, (ii) a butane isomerization facility and related pipeline system, (iii) octane enhancement and high purity isobutylene production facilities, (iv) refined products pipelines, including our Products Pipeline System (as defined below), and related marketing activities and (v) marine transportation and other services.

Propylene fractionation and related activities. Our propylene fractionation and related activities primarily consist of two propylene fractionation plants (one located in Mont Belvieu, Texas and the other in Baton Rouge, Louisiana), propylene pipeline systems aggregating approximately 680 miles in length and related petrochemical marketing activities. This business includes an export facility and associated above-ground polymer grade propylene storage spheres located in Seabrook, Texas.

In general, propylene fractionation plants separate refinery grade propylene, which is a mixture of propane and propylene, into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of ethylene production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery and molded plastic parts for appliances and automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. The toll processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation. Our petrochemical marketing activities generate revenues from the purchase and fractionation of refinery grade propylene in the open market and the sale and delivery of products obtained through our propylene fractionation activities. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location. The majority of revenues from our propylene pipelines are based upon a transportation fee per unit of volume multiplied by the volume delivered to the customer.

As part of our petrochemical marketing activities, we have several long-term refinery grade propylene purchase and polymer grade propylene sales agreements. To limit the exposure of our petrochemical marketing activities to commodity price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Butane isomerization. Our butane isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization facility in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Table of Contents

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high-purity isobutane and residual normal butane. The primary uses of isobutane are for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of isomerization. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility.

Octane enhancement and high purity isobutylene. We own and operate an octane enhancement production facility located in Mont Belvieu, Texas that is designed to produce isooctane, isobutylene and methyl tertiary butyl ether ("MTBE"). The products produced by this facility are used in reformulated motor gasoline blends to increase octane values. The high-purity isobutane feedstocks consumed in the production of these products are supplied by our isomerization units. To the extent that MTBE is produced at our Mont Belvieu facility, it is strictly sold into the export market.

The results of operations of this business are generally dependent upon the sale and delivery of products produced. In general, we sell our octane enhancement products at market-based prices, which may include pricing differentials for such factors as delivery location. We attempt to mitigate price risk by entering into certain commodity hedging transactions. Our Mont Belvieu facility undergoes an annual maintenance turnaround that generally occurs during the first quarter of each year. During these periods of shutdown, the plant may incur operating losses.

In November 2010, we acquired a facility located on the Houston Ship Channel that produces high purity isobutylene ("HPIB"). The feedstock for this plant is produced by our octane enhancement facility in Mont Belvieu, Texas. High purity isobutylene is used in the production of alkylated phenols used as antioxidants, lube oil additives, butyl rubber and resins. For information regarding our business acquisitions in 2010, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Refined products pipelines and related activities. Our refined products pipelines and related activities primarily consist of (i) a regulated 4,700-mile products pipeline system and related terminal operations (the "Products Pipeline System") that generally extends in a northeasterly direction from the upper Texas Gulf Coast to the northeast United States and (ii) a 50% joint venture interest in Centennial Pipeline LLC ("Centennial"), which owns a 795-mile refined products pipeline system that extends from the upper Texas Gulf Coast to central Illinois (the "Centennial Pipeline").

The Products Pipeline System transports refined products, and to a lesser extent, petrochemicals such as ethylene and propylene and NGLs such as propane and normal butane. These refined products are produced by refineries and include gasoline, diesel fuel, aviation fuel, kerosene, distillates and heating oil. Refined products also include blend stocks such as raffinate and naphtha. Blend stocks are primarily used to produce gasoline or as a feedstock for certain petrochemicals. The Centennial Pipeline intersects our Products Pipeline System near Creal Springs, Illinois, and effectively loops the Products Pipeline System between Beaumont, Texas and south Illinois. Looping the Products Pipeline System permits effective supply of products to points south of Illinois as well as incremental product supply capacity to other Midcontinent markets.

Our refined products pipelines and related activities include six refined products truck terminals located along the Products Pipeline System. In addition, we have refined products truck terminals located at Aberdeen, Mississippi and

Boligee, Alabama adjacent to the Tombigbee River. Also, in November

2010, we acquired a refined products storage facility (0.6 MMBbls of capacity) and barge dock located on the Houston Ship Channel in Pasadena, Texas.

The results of operations of our refined products pipelines are primarily dependent on the tariffs charged to customers to transport products. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. The results of our storage assets are primarily dependent on the volume and associated fees paid by third parties. Our related marketing activities generate revenues from the sale and delivery of refined products obtained from third parties on the open market. In general, we sell our refined products at market-based prices, which may include pricing differentials for such factors as delivery location.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are primarily used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products along key inland and intercoastal U.S. waterways. Our marine transportation assets service refinery and storage terminal customers along the Mississippi, Illinois and Ohio rivers, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. In November 2010, we acquired a marine shipyard and related assets that support our marine transportation business. These assets include a shipyard and repair facility located in Houma, Louisiana and marine fleeting facilities in Bourg and Amelia, Louisiana and Channelview, Texas. For information regarding our business acquisitions in 2010, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Other non-marine services consist of the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels by truck, principally in Oklahoma, Texas, New Mexico, Kansas and the Rocky Mountain region of the United States. In September 2010, we acquired EPCO’s ownership interests in Enterprise Transportation Company (“ETC,” a trucking business) in exchange for 523,306 of our common units. ETC utilizes a fleet of approximately 800 tractor-trailer tank trucks, which are mainly used to transport NGL, petrochemical and refined products. ETC’s fleet is supported by 26 truck terminals, which we own and operate in numerous locations throughout the United States. For information regarding this drop down transaction, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The results of operations of our marine transportation business are generally dependent upon the level of fees charged to transport cargo. Transportation services are typically provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement.

The results of operations from other non-marine services are dependent on the sales price or transportation fees that we charge our customers.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher levels of demand in the spring and summer months due to increased demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, octane additive prices have been stronger during the April to September period of each year, which corresponds with the summer driving season, when motor gasoline demand increases.

Our refined products pipelines and related activities exhibit seasonality based upon the mix of products delivered and the weather and economic conditions in the geographic areas being served. Refined products volumes are generally higher during the second and third quarters of each year because of greater demand for motor gasoline during the spring and summer driving seasons. NGL transportation volumes on the Products Pipeline System are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline and asphalt is generally stronger in the spring and summer months due to the summer driving season and when weather allows for more efficient road construction. Weather events, such as hurricanes and tropical

Table of Contents

storms in the Gulf of Mexico, can adversely impact both the offshore and inland businesses. Generally during the winter months, cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage supporting infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

The Products Pipeline System's most significant competitors are third-party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the areas served by our Products Pipeline System and river terminals. The Products Pipeline System faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with other inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. Competition within the marine transportation business is largely based on price.

Table of Contents

Properties. The following table summarizes the significant production facilities and pipelines included in our Petrochemical & Refined Products Services business segment at February 1, 2011, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various (1)	73	87	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100% (4)			288
North Dean Pipeline System	Texas	100%			147
Texas City RGP Gathering System	Texas	100%			86
Others (6 systems) (5)	Texas, Louisiana	Various (6)			225
Total miles					746
Octane enhancement and HPIB production facilities:					
Mont Belvieu (7)	Texas	100%	12	12	
Houston Ship Channel (8)	Texas	100%	4	4	
Total capacity			16	16	

(1) We own a 66.7% interest in three of the units, which have an aggregate 41 MBPD of total plant capacity. We own 100% of the remaining three units.
(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC (“BRPC”).
(3) On a weighted-average basis, utilization rates for this facility were approximately 76.7%, 83.6% and 74.1% during the years ended December 31, 2010, 2009 and 2008, respectively.
(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).
(5) Includes our Texas City PGP Delivery System and Port Neches, La Porte, Port Arthur, Lake Charles and Bayport petrochemical pipelines.
(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C. In addition, we own a 50% undivided interest in the Lake Charles pipeline.
(7) On a weighted-average basis, utilization rates for this facility were approximately 71%, 50% and 58.3% during the years ended December 31, 2010, 2009 and 2008, respectively.
(8) In November 2010, we acquired a facility located on the Houston Ship Channel that produces high-purity isobutylene.

We produce polymer grade propylene at our Mont Belvieu, Texas propylene fractionation facility and chemical grade propylene at our BRPC facility located in Baton Rouge, Louisiana. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The polymer grade propylene produced by our Mont Belvieu facility is primarily for the benefit of our tolling customers and used in our petrochemical marketing activities to service long-term third-party supply contracts. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 95.3%, 85% and 72.2% during the years ended December 31, 2010, 2009 and 2008, respectively. As noted previously, this business includes an export facility and above-ground polymer grade propylene storage spheres. This facility, which is located on the Houston Ship Channel in Seabrook, Texas, can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a third-party pipeline interconnect located in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas.

Table of Contents

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 135 MBPD, 124 MBPD and 116 MBPD during the years ended December 31, 2010, 2009 and 2008, respectively.

The following table summarizes the significant refined products pipelines and related terminal and storage assets included in our Petrochemical & Refined Products Services business segment at February 1, 2011.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Usable Storage Capacity (MMBbls)
Refined products pipelines and terminals:				
Products Pipeline System (1)	Texas to Midwest and Northeast U.S.	100%	4,700	17.5
Centennial Pipeline	Texas to central Illinois	50% (2)	795	2.3
Other pipelines (3)	Texas	100%	210	n/a
Other terminals (4)	Alabama, Mississippi, Texas	100%	n/a	1.2
Total			5,705	21.0

(1) In addition to the 17.5 MMBbls of refined products working storage capacity, we have 5.6 MMBbls of NGL working storage capacity that is used to support operations on our Products Pipeline System. Our NGL storage and terminal assets are accounted for under our NGL Pipelines & Services business segment.
(2) Our ownership interest in this pipeline is held indirectly through our equity method investment in Centennial.
(3) Our Products Pipeline System includes 210 miles of unregulated pipelines in South Texas used primarily to transport petrochemical products.
(4) Includes product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama having a working storage capacity of 0.1 MMBbls and 0.5 MMBbls, respectively, and storage terminals located in Pasadena, Texas having a total working storage capacity of 0.6 MMBbls. We acquired the Pasadena, Texas terminal in November 2010.

The maximum number of barrels that our refined products pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our liquids pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for the Products Pipeline System were as follows for the periods presented:

	For Year Ended December 31,		
	2010	2009	2008
Refined products transportation (MBPD)	511	459	492
Petrochemical transportation (MBPD)	122	118	104
NGLs transportation (MBPD)	101	105	106

The following information highlights the general use of each of our principal refined products pipelines and related assets.

§ The Products Pipeline System is a regulated pipeline system that transports refined products, petrochemicals and NGLs. This pipeline system includes receiving, storage and terminaling facilities and is present in 12 states: Texas, Louisiana, Arkansas, Tennessee, Missouri, Illinois, Kentucky, Indiana, Ohio, West Virginia, Pennsylvania and New York. Our Products Pipeline System transports refined products from the upper Texas Gulf Coast, eastern Texas and southern Arkansas to the Central and Midwest regions of the United States with deliveries in Texas, Louisiana, Arkansas, Missouri, Illinois, Indiana, Ohio and Kentucky. At these points, refined products are delivered to terminals owned by us, connecting pipelines and customer-owned terminals. Petrochemicals are transported on our Products Pipeline System between Mont

Table of Contents

Belvieu, Texas and Port Arthur, Texas. Our Products Pipeline System transports NGLs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is the only pipeline that transports NGLs from the upper Texas Gulf Coast to the Northeast. The Centennial Pipeline effectively loops our Products Pipeline System between Beaumont, Texas and southern Illinois.

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") to construct and operate a refined products storage facility to support an expansion of Motiva's refinery in Port Arthur, Texas. In June 2010, we completed construction and commenced commercial operations of 20 storage tanks with a capacity of 5.3 MMBbls for gasoline and distillates, five 5-mile product pipelines connecting the storage facility to Motiva's refinery and distribution pipeline connections to the Colonial, Explorer and Sunoco pipelines. As part of a separate but complementary initiative, we constructed an 11-mile pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas.

§ Centennial Pipeline is a regulated refined products pipeline system that extends from Texas to Illinois. The Centennial Pipeline extends from an origination facility located on our Products Pipeline System in Beaumont, Texas, to Bourbon, Illinois. Centennial owns a 2.3 MMBbl refined products storage terminal located near Creal Springs, Illinois.

The following table summarizes the significant marine transportation assets included in our Petrochemical & Refined Products Services business segment at February 1, 2011.

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp) (as indicated by sign)
Inland marine transportation assets:		
Barges	19	< 25,000 bbl
Barges	93	> 25,000 bbl
Tow boats	24	< 2,000 hp
Tow boats	27	≥ 2,000 hp
Offshore marine transportation assets:		
Barges	5	≥ 20,000 bbl
Tow boats	4	< 2,000 hp
Tow boats	3	> 2,000 hp

Our fleet of marine vessels operated at an average utilization rate of 91.9%, 87.5% and 93% during 2010, 2009 and 2008, respectively. These utilization rates reflect the period since we acquired these marine transportation assets.

The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. We refer to the combination of the power source and freight capacity as a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, location, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge.

In June 2010, we acquired a marine transportation business located in south Louisiana for $12.0 million in cash that included three tow boats and five tank barges. In November 2010, we acquired certain assets from Cenac Towing

Co., L.L.C., Cenac Offshore, L.L.C., CTCO Marine Services, LLC, and CTCO Shipyard of Louisiana, LLC relating to their marine shipyard operations in Louisiana and certain membership interests in CTCO of Texas, L.L.C. and Channelview Fleeting Services, LLC relating to their marine shipyard operations in Texas. This transaction was valued at $141.9 million and the consideration consists of $42.2 million in cash and $99.7 million of our common units (represented by approximately 2.3 million common units). Since we entered into the marine transportation business in 2008, we have paid the above entities for services to support this business including construction, repairs and maintenance, drydock and provisioning services. We expect these acquired assets will result in significant future cost savings for our marine fleet. For information regarding our business acquisitions in 2010, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our marine transportation business is subject to regulation by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws.

In February 2011, we sold towboats and tank barges used in bunker fuel service that were originally acquired in June 2009 from TransMontaigne Product Services Inc. The sales price of these assets was approximately $53.2 million.

Other Investments

This segment reflects our noncontrolling ownership interests in Energy Transfer Equity, which is accounted for using the equity method. In May 2007, Holdings paid $1.65 billion to acquire 38,976,090 common units of Energy Transfer Equity and approximately 34.9% of the membership interests of LE GP, its general partner. In January 2009, Holdings acquired an additional 5.7% membership interest in LE GP for $0.8 million, which increased our total ownership in LE GP to 40.6%. In December 2010, we sold our entire membership interest in LE GP and recorded a nominal gain on the transaction.

Energy Transfer Equity has no separate operating activities apart from those of ETP and RGNC. As of December 31, 2010, Energy Transfer Equity's principal sources of distributable cash flow were its investments in the limited and general partner interests of ETP and RGNC as follows:

§ Direct ownership of 50,226,967 limited partner units of ETP representing approximately 26% of ETP's total outstanding units.

§ Indirect ownership of the general partner of ETP (representing a 1.8% interest in ETP as of December 31, 2010) and all associated IDRs in ETP held by such general partner. ETP's partnership agreement requires that it distribute all of its Available Cash (as defined in such agreement) within 45 days following the end of each fiscal quarter. Currently, the quarterly cash distributions that Energy Transfer Equity receives from its ownership of ETP's general partner are based on its general partner interest in ETP, plus the following with respect to the IDRs:

§ 13% of quarterly cash distributions from $0.275 per unit up to $0.3175 per unit paid by ETP;

§ 23% of quarterly cash distributions from $0.3175 per unit up to $0.4125 per unit paid by ETP; and

§ 48% of quarterly cash distributions that exceed $0.4125 per unit paid by ETP.

§ Direct ownership of 26,266,791 limited partner units of RGNC representing approximately 19% of the total outstanding RGNC units.

§ Indirect ownership of the general partner of RGNC (representing a 2.0% interest in RGNC as of December 31, 2010) and all associated IDRs in RGNC held by such general partner. RGNC's partnership agreement requires that it distribute all of its Available Cash (as defined in such agreement) within 45 days following the end of each fiscal quarter. Currently, the quarterly cash distributions that Energy Transfer Equity receives from its ownership of RGNC's general partner are based on its general partner interest in RGNC, plus the following with respect to the IDRs:

§ 13% of quarterly cash distributions from $0.4025 per unit up to $0.4375 per unit paid by RGNC;

§ 23% of quarterly cash distributions from $0.4375 per unit up to $0.525 per unit paid by RGNC; and

Table of Contents

§ 48% of quarterly cash distributions that exceed $0.525 per unit paid by RGNC.

ETP is a publicly traded partnership that owns and operates a diversified portfolio of midstream energy assets. ETP has pipeline operations in Arizona, Colorado, Louisiana, New Mexico and Utah, and owns the largest intrastate natural gas pipeline system in Texas. ETP's natural gas operations include natural gas gathering and transportation pipelines, natural gas treating and processing assets and three natural gas storage facilities located in Texas. ETP is also one of the three largest retail marketers of propane in the United States, serving more than one million customers across the country.

RGNC is a publicly traded partnership engaged in the gathering, treating, processing, compressing and transporting of natural gas and NGLs. RGNC provides these services through systems located in Louisiana, Texas, Arkansas, Pennsylvania and the mid-continent region of the United States, which includes Kansas, Colorado, and Oklahoma. RGNC's midstream assets are primarily located in well-established areas of natural gas production that have been characterized by long-lived, predictable reserves.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material 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.

Regulation

Interstate Pipelines

Liquids Pipelines. Certain of our refined products, crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues together with interest in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates and related rules that are already in effect and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deems just and reasonable (i.e., deems "grandfathered") liquids pipeline rates that (i) were in effect for the 12 months preceding enactment and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer

Table of Contents

Price Index for finished goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's costs. During the five-year period commencing July 1, 2006 and ending June 30, 2011, liquids pipelines charging indexed rates were permitted to adjust their indexed ceilings annually by the PPI plus 1.3%. On December 16, 2010, the FERC established a new price index to calculate the annual changes to ceiling levels for oil pipeline rates for the five-year period beginning July 1, 2011. The FERC determined that liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 2.65%. Several parties have filed requests for rehearing of the December 16, 2010 order issued in Docket No. RM10-25. The FERC has not yet addressed those rehearing requests.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements with all of the pipeline's shippers that the rate is acceptable. Our Products Pipeline System has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than movements to the Little Rock, Arkansas; Jonesboro, Arkansas; and Arcadia, Louisiana destination markets, which are currently subject to the PPI.

Due to the complexity of ratemaking, the lawfulness of any rate is never assured. Prescribed rate methodologies for approving regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC's methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

Mid-America Pipeline Company, LLC ("Mid-America") and Seminole are currently involved in a rate case before the FERC. The case primarily involves shipper protests of rate increases on Mid-America's Northern System in FERC Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000, and challenges to Seminole's interstate rates and certain joint rates between Seminole and Mid-America's Rocky Mountain System in FERC Docket Nos. OR06-5-000 and IS06-520-000. A hearing before an Administrative Law Judge began on October 2, 2007 and culminated with an initial decision on September 3, 2008. On October 23, 2009, the FERC approved an uncontested settlement agreement between Mid-America and the primary parties protesting the Northern System rates, which resolved all matters involving Mid-America's Northern System at issue in Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000. Pursuant to the settlement agreement, Mid-America filed new rates for certain propane movements on the Northern System, which took effect January 1, 2010. Mid-America also paid refunds to propane shippers, as provided by the settlement agreement. On March 2, 2010, Mid-America filed a refund report with the FERC describing the refunds paid. The FERC accepted the refund report on July 22, 2010.

The settlement agreement did not cover the challenges to the Seminole and Mid-America Rocky Mountain System rates at issue in Docket Nos. OR06-5-000 and IS06-520-000. On February 18, 2010, the FERC ruled on those issues, affirming the Initial Decision in all respects. The FERC's order also clarified that Mid-America's capacity allocation provisions were not subject to challenge in the case but that the changes to Mid-America's rates contained in FERC Tariff No. 45 were properly at issue. On March 22, 2010, Mid-America and Seminole filed a compliance filing calculating rates consistent with the FERC's February 18, 2010 order. Two parties protested the revised rates. The FERC has not ruled on those protests and we are unable to predict the outcome of that proceeding.

On April 13, 2010, Enterprise TE Products Pipeline Company LLC ("Enterprise TEPPCO") filed tariffs in FERC Docket No. IS10-203-000, making certain revisions to its propane inventory policy. A protest was filed by a group of propane shippers (the "Propane Group I"). Various other parties later intervened. On May 13, 2010, the FERC accepted Enterprise TEPPCO's tariff subject to the condition that the pipeline submit its prorationing and propane inventory policies to the FERC for review. On May 19, 2010, Enterprise TEPPCO submitted its policies to the FERC as requested. On June 3, 2010, the Propane Group I and Texas Liquids Partners, LLC sought rehearing of the FERC's order accepting the tariff. On

Table of Contents

October 12, 2010, the FERC ruled on the rehearing request and established a hearing to determine whether the propane inventory policy is just and reasonable. The FERC held the hearing in abeyance pending settlement judge procedures. The settlement judge procedures remain ongoing at the FERC and we are unable to predict the outcome of that proceeding.

On May 25, 2010, Enterprise TEPPCO filed its indexed rates in FERC Docket No. IS10-287-000, for the July 1, 2010 through June 30, 2011 period. On June 9, 2010, a protest was filed by various propane shippers (the "Propane Group II"). The Propane Group II argued that Enterprise TEPPCO should have reduced the ceiling rate for propane movements by 42 cents to reflect the removal of certain terminaling charges and new lower propane transportation rates that took effect April 1, 2010. On June 14, 2010, Enterprise TEPPCO withdrew the challenged tariffs and filed new tariffs containing new indexed ceilings that were 42 cents below the prior ceilings. Enterprise TEPPCO also lowered its indexed ceilings and propane transportation rates by 1.2974% as required by the indexing adjustment for the July 1, 2010 through June 30, 2011 period. On June 28, 2010, the Propane Group II protested the new tariffs in Docket No. IS10-287-002. The Propane Group II argued that Enterprise TEPPCO should have further reduced its ceiling levels to reflect alleged changes in service related to line fill, inventory and storage. The FERC has not acted on the protest, and the tariff took effect July 1, 2010. Enterprise TEPPCO is unable to predict what, if any, further actions the FERC may take in this proceeding.

On November 30, 2010, ConocoPhillips Company ("ConocoPhillips") filed a complaint at the FERC against Enterprise TEPPCO in FERC Docket No. OR11-3-000. The complaint relates to an exchange agreement between Enterprise TEPPCO and ConocoPhillips in which ConocoPhillips provides propane to Enterprise TEPPCO at a location near the ConocoPhillips refinery in Trainer, Pennsylvania in exchange for propane provided by Enterprise TEPPCO to ConocoPhillips at Mont Belvieu, Texas ("Exchange Agreement"). On March 25, 2010, Enterprise TEPPCO provided notice terminating the Exchange Agreement effective March 31, 2011, as permitted by its terms. The ConocoPhillips complaint asks the FERC to require Enterprise TEPPCO to (1) continue to participate in the Exchange Agreement despite the notice of termination, (2) include the terms of the Exchange Agreement in Enterprise TEPPCO's tariff along with any other exchange agreements to which Enterprise TEPPCO is a party, and (3) list ConocoPhillips' Trainer refinery as an origin in Enterprise TEPPCO's tariff and publish initial rates from that origin to all Enterprise TEPPCO destinations. On December 22, 2010, Enterprise TEPPCO submitted its answer to the complaint. The FERC has not ruled on the complaint and we are unable to predict the outcome of this proceeding.

The Lou-Tex Propylene and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board ("STB"). If the STB finds that a carrier's rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 ("NGA"). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

Table of Contents

The FERC's authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also extends to: (i) the construction and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. The FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation employees function independently of marketing employees. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

In January 2010, we filed an application for a certificate of public convenience and necessity seeking authority under Section 7(c) of the NGA for Petal Gas Storage, L.L.C. to convert, operate and maintain an existing salt brine production cavern for use as a new salt dome natural gas storage cavern with a capacity of 8.2 Bcf. In August 2010, the FERC issued an order issuing the certificate.

In September 2010, we submitted an amended Statement of Operating Conditions ("SOC") for the natural gas storage and transportation services of Hattiesburg Industrial Gas Sales Company. The FERC has not yet issued an order approving the amended SOC.

In March 2009, we submitted to the FERC a general rate change application under Section 4 of the NGA proposing, among other things, an increase in the firm and interruptible transportation rates for High Island Offshore System, LLC. On April 23, 2009, the FERC issued an order accepting the rates subject to refund, conditions and the outcome of an evidentiary hearing. The rates went into effect subject to refund in October 2009. Also, in March 2009, HIOS filed a petition requesting the FERC to declare that all facilities at and upstream of the High Island Area ("HIA") Block 264 platform perform a non-jurisdictional gathering function. Finally, in January 2010, as a result of a platform fire at HIA Block 264, HIOS filed an application seeking approval to abandon by removal the three compressor units on the platform and to reduce the level of HIOS's certificated capacity. In March 2010, HIOS submitted to the FERC on behalf of itself, the FERC's Staff and the active intervenors, a settlement agreement intended to resolve all outstanding issues in these proceedings. In April 2010, pending the FERC's action on the proposed settlement, HIOS filed to place reduced rates under the proposed settlement into effect on an interim basis. In June 2010, the FERC issued an order accepting the reduced rates subject to the FERC's decision on the proposed settlement and to refund or surcharge. Therefore, the interim rates will remain in effect until the earlier of April 2011 or the date the settlement becomes effective.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma and Texas.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our

Table of Contents

intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline may transport gas on behalf of an interstate pipeline company or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, to post certain transactional information on its website, and to make certain rate and other filings and reports in compliance with the FERC's regulations. The rates for Section 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

In June and July 2008, we filed to amend our Statement of Operating Conditions ("SOC") for transportation and storage services on our Enterprise Texas Pipeline. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline. Certain shippers challenged aspects of the previous SOC changes, and the methodology used to charge shippers using the Sherman Extension. On November 23, 2009, we filed an uncontested settlement agreement that resolved the Sherman Extension rate issues, while reserving certain SOC related issues for a decision by the FERC based on the pleadings. By order issued in March 2010, the FERC approved the uncontested settlement agreement, the SOC for storage services, as filed, and the SOC for transportation services, subject to conditions. We submitted a filing in compliance with the March order, which compliance filing remains pending at this time. On April 1, 2010, we filed a rate petition for the two zones established by the settlement approved by the FERC in March 2010. On September 23, 2010, we filed an uncontested settlement which was approved by the FERC on December 16, 2010. Under this settlement, we are required to justify our settlement rates or establish new rates for NGPA Section 311 service on or before March 31, 2015.

In May 2010, as required by the terms of a FERC order approving a previous rate settlement, we submitted a petition to the FERC to justify our current rates for NGPA Section 311 service on our Enterprise Alabama Intrastate Pipeline system. The petition was granted by order issued in July 2010. The Alabama Public Service Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Alabama.

In July 2009, we filed with the FERC proposed changes to our SOC and to increase our interruptible transportation rates for NGPA Section 311 service for the Acadian and Cypress pipelines, which are part of our Acadian Gas System. On July 26, 2010, the FERC issued two orders approving the uncontested settlements resolving the rate issues filed in separate rate proceedings by Cypress and Acadian. Under the approved settlements, Cypress and Acadian are required, on or before July 13, 2014, to file rate petitions to either justify their current rates or propose new rates.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction. However, under current federal rules the price at which we sell natural gas is not regulated insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing are considered marketing affiliates of certain of our interstate natural gas pipelines. The FERC's rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transportation and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has also established rules prohibiting energy market manipulation. A violation of these rules by us or our employees or agents may subject us to civil penalties, suspension or loss of authorization to perform such sales, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. The Federal Trade Commission and the Commodity Futures Trading Commission also have issued rules and regulations prohibiting market manipulation.

Table of Contents

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC has adopted new market monitoring and annual reporting regulations which are applicable to many intrastate pipelines and other entities that are otherwise not subject to the FERC's NGA jurisdiction. The FERC also has established rules requiring certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. Non-interstate service providers, which include NGPA Section 311 service providers, were required to begin posting the information by October 1, 2010. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Marine Operations

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues.

Jones Act. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. As a result of our marine transportation business acquisition on February 1, 2008, we now engage in coastwise maritime transportation between locations in the United States, and as such, we are subject to the provisions of the Jones Act. As a result, we are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flag vessels be manned by United States citizens. Foreign seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flag vessel owners. The USCG and American Bureau of Shipping ("ABS") maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flag operators than for owners of vessels registered under foreign flags of convenience. Following Hurricane Katrina, and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could adversely affect our cash flow. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness. In certain circumstances, a Jones Act seaman can have dual employers under the borrowed servant doctrine.

Merchant Marine Act of 1936. The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the president of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

43

Table of Contents

For additional information regarding the potential impact of federal, state or local regulatory measures on our business, please read Item 1A "Risk Factors" of this annual report.

Environmental and Safety Matters

Our pipelines and other facilities are subject to multiple environmental and safety obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"); the Resource Conservation and Recovery Act ("RCRA"); the Federal Clean Air Act ("CAA"); the Federal Water Pollution Control Act of 1972, renamed and amended as the Clean Water Act ("CWA"); the Oil Pollution Act of 1990 ("OPA"); the Federal Occupational Safety and Health Act, as amended ("OSHA"); the Emergency Planning and Community Right to Know Act; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our financial position, results of operations and cash flows. If a leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed in Note 18 of the Notes to Consolidated Financial Statements under Item 8 of this annual report, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. Below is a discussion of the material environmental laws and regulations that relate to our business.

Air Emissions

Our operations are associated with emissions of air pollution and are subject to the CAA and comparable state laws and regulations including state implementation plans. These laws and regulations regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

Table of Contents

Climate Change Regulation

Responding to scientific studies that have been suggested that emissions of gases, commonly referred to as “greenhouse gases.” including gases associated with the oil and gas sector such as carbon dioxide, methane and nitrous oxide among others, may be contributing to warming of the earth’s atmosphere and other adverse environmental effects, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. The U.S. Environmental Protection Agency (“EPA”) has also taken action under the CAA to regulate greenhouse gas emissions. In addition, some states, including states in which our facilities or operations are located, have taken or proposed legal measures to reduce emissions of greenhouse gases.

In the 111th Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the 112th Congress which convened in January 2011. However, any such legislation may have the potential to affect our business, customers or the energy sector generally.

In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change (“UNFCCC”). Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the UNFCCC and a subsidiary agreement known as the “Kyoto Protocol,” an international treaty pursuant to which participating countries have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. The United States is a party to the UNFCCC but did not ratify the Kyoto Protocol. Such negotiations have not thus far resulted in substantive changes that would affect domestic industrial sources in the United States and it is uncertain whether an international agreement will be reached or what the terms of any such agreement would be.

Following the U.S. Supreme Court’s decision in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the CAA definition of “air pollutant,” the EPA determined that greenhouse gases from certain sources “endanger” public health or welfare. The EPA subsequently promulgated certain regulations and interpretations that will require new and modified stationary sources of greenhouse gases above certain thresholds to report, limit or control such emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA’s Prevention of Significant Deterioration (“PSD”) and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with “best available control technology” standards if deemed to be cost-effective. Such changes will also affect state air permitting programs in states that administer the CAA under a delegation of authority, including states in which we have operations. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective, and will remain so unless overturned by a court, or unless Congress adopts legislation altering the EPA’s regulatory authority. The EPA has also announced its intention to promulgate additional regulations restricting greenhouse gas emissions, including rules applicable to the power generation sector and oil refining sector.

A number of states, individually or in regional cooperation, have also imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content. These initiatives include the following. Ten states in the Northeast and Mid-Atlantic region signed a compact and have implemented rules to limit carbon dioxide emissions from power plants under the Regional Greenhouse Gas Initiative (“RGGI”) which requires electric generating facilities to purchase emissions allowances corresponding to their respective emissions under a cap-and-trade system. The California Air Resources Board has issued a series of rules under that state’s Global Warming Solutions Act, including restrictions on greenhouse gas emissions from industrial sources

Table of Contents

and regulating the carbon content of fuels. In December 2010, the California Air Resources Board approved rules that will require sources in the industrial, power, and fuels sectors to hold allowances for greenhouse gas emissions under a cap-and-trade system beginning in January 2012. In addition, in November 2010, the New Mexico Environmental Improvement Board adopted new regulations pursuant to state law establishing a greenhouse gas cap-and-trade system to be implemented by the New Mexico Environment Department. These and other states have indicated that they may pursue additional emissions limitations.

These federal, regional and state measures generally apply to industrial sources, including facilities in the oil and gas sector, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and could by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources, adversely affect market demand or pricing for our products or products served by our midstream infrastructure. All this, or any future such developments, may have an adverse effect on our business, financial position, results of operations and cash flows.

There have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector generally. First, in September 2009, the United States Court of Appeals for the Second Circuit issued its decision in Connecticut v. American Electric Power Co., 582 F.3d 309 (2d Cir. Sept. 21, 2009). With this case, the Second Circuit held that certain state and private plaintiffs could sue energy companies on the asserted basis that greenhouse gas emissions created a "public nuisance." The U.S. Supreme Court has agreed to review that decision. Second, a three-judge panel of the United States Court of Appeals for the Fifth Circuit initially upheld claims in Comer v. Murphy Oil USA, 585 F.3d 855 (5th Cir. Oct. 16, 2009), by property owners who suffered casualty losses in Hurricane Katrina alleging that certain energy, fossil fuel and chemical industries emitted greenhouse gases that contributed to global warming and ultimately exacerbated property damage from the hurricane. The Fifth Circuit subsequently vacated the panel decision and, because of a procedural issue, was unable to review the merits of the claims. A similar case, Native Village of Kivalina v. ExxonMobil Corp., 663 F. Supp. 2d 863 (N.D. Cal. Sept. 30, 2009), dismissed similar claims for lack of subject matter jurisdiction, and this decision was appealed to and remains pending before the United States Court of Appeals for the Ninth Circuit. These cases expose other significant emission sources of greenhouse gases to similar litigation risk.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage.

Physical Impacts of Climate Change

There is considerable debate over global warming and the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans and ecosystems. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming or various aspects of the scientific debate. However, if global warming is occurring, it could have an impact on our operations. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels, or disruption of operations