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.

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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.

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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

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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.

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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.

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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

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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

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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.

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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

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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.

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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

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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.

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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.

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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.

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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.

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§ 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.

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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

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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

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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.

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.

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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.

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§ 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

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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.

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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.

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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.

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- § 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

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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

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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.

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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.

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§ 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.

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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 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.

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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.

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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

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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

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§ 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

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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

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.

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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

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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.

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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.

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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.

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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

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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

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from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of global warming. We are providing this disclosure based on publicly available information on the matter.

Water

The CWA and comparable state laws impose strict controls on the discharge of oil and its derivatives into regulated waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting regulated waters. The EPA has also adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate and may impose certain monitoring and other requirements. The CWA further prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our operations.

The primary federal law for oil spill liability is the OPA, which addresses three principal areas of oil pollution: prevention, containment and cleanup and liability. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the USCG, the United States Department of Transportation Office of Pipeline Safety (“OPS”) or the EPA, as appropriate. Numerous states have enacted laws similar to OPA. Under OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resource damages. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems or other facilities as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific, and there is no assurance that the effect will not be material in the aggregate.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste.

Endangered Species

The federal Endangered Species Act, as amended, and comparable state laws, may restrict activities that affect endangered and threatened species or their habitats. Some of our current or future planned facilities may be located in areas that are designated as habitat for endangered or threatened species, and if so may limit or impose increased costs on facility construction or operation. In addition, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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Environmental Remediation

CERCLA, also known as "Superfund," imposes liability, often without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, responsible parties may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and RCRA also authorize the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, our pipeline systems and other facilities generate wastes that may fall within CERCLA's definition of a "hazardous substance" or be subject to CERCLA and RCRA remediation requirements. It is possible that we could incur liability for remediation or reimbursement of remediation costs under CERCLA or RCRA for remediation at sites we currently own or operate, whether as a result of our or our predecessors' operations, at sites that we previously owned or operated, or at disposal facilities previously used by us, even if such disposal was legal at the time it was undertaken.

Pipeline Safety Matters

We are subject to regulation by the DOT under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act ("HLPSA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Secretary of Transportation. We believe we are in material compliance with these HLPSA regulations.

We are also subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. In addition, we are subject to the DOT regulation that requires pipeline operators to institute certain control room procedures. These procedures must be developed by August 1, 2011 and implemented by February 2, 2012. We believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program that utilizes internal pipeline inspection, pressure testing or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In June 2008, the DOT extended its pipeline safety regulations, including Integrity Management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around "unusually sensitive areas." We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

The DOT recently issued several new proposals to increase safety standards for pipelines. In June 2010, the DOT issued a Notice of Proposed Rulemaking that proposes to amend the pipeline safety regulations to apply the regulations to rural low-stress hazardous liquid pipelines that are not covered by the regulations in 49 CFR Part 195. The proposed rule would apply to all small-diameter (less than 8 5/8 inches) rural low-stress pipelines located within a 1/2 mile of an Unusually Sensitive Area ("USA") and to all rural low-stress pipelines of any diameter located outside the 1/2 mile USA buffer. The DOT also issued an Advance Notice of Proposed Rulemaking in October 2010 in which it is considering whether to remove or modify regulatory exemptions that currently exist in the pipeline safety regulations for the gathering of hazardous liquids by pipeline in rural areas. The comment period for this notice ended on February 18, 2011. The DOT also has proposed new legislation to the U. S. Congress in September 2010 entitled the Strengthening Pipeline Safety and Enforcement Act of 2010. The DOT Secretary has stated that this proposed legislation would provide stronger oversight of the nation's pipelines, increase the penalties for violations of pipeline safety rules and complements the DOT's other initiatives. Specifically, the proposed legislation would, among other things, increase the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 to $2.5 million; require a review of whether rules requiring the strictest safety requirements only for HCAs should be applied to entire pipelines, including sections located in rural areas; eliminate exemptions from safety regulations for pipelines that gather liquids upstream of transmission lines; and provide for improved coordination with states and other agencies. We cannot predict whether or if such DOT proposed rules and legislation will be adopted.

Risk Management Plans

We are subject to the EPA’s Risk Management Plan regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act (“OSHA”) Process Safety Management (“PSM”) regulations (see “Safety Matters” below) to minimize the offsite consequences of catastrophic releases. The regulations require us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with our risk management program.

Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

Certain of our facilities are subject to OSHA PSM regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to federal, state and local governmental authorities and local citizens upon request. These laws and provisions of CERCLA require reporting of spills and releases of hazardous chemicals in certain situations.

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the “ASA”) or by other service providers. For additional information regarding the ASA, see “EPCO ASA” in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. As of December 31, 2010, there were approximately 6,570 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 1,500 of these individuals devote all of their time performing administrative, commercial and operating duties for us. The remaining

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approximately 5,070 personnel are part of EPCO's shared service organization and spend all or a portion of their time engaged in our business.

Available Information

As a publicly traded partnership, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations department at (866) 230-0745 for paper copies of these reports free of charge. We do not intend to incorporate the information on our website into this document.

Additionally, Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the SEC, including annual reports on Form 10-K and quarterly reports on Form 10-Q. These entities also provide electronic access to their respective periodic and current reports on their Internet websites. The SEC file number for each registrant and company website address is as follows:

§ Duncan Energy Partners – SEC File No. 1-33266; website address: www.deplp.com

§ Energy Transfer Equity – SEC File No. 1-32740; website address: www.energytransfer.com

Prior to the Holdings Merger, Holdings also filed periodic and current reports with the SEC. Holdings' SEC file number was 1-32610. The reporting requirements for Holdings were suspended in December 2010 following the Holdings Merger.

Item 1A. Risk Factors.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our common units could decline and you could lose part or all of your investment.

The following section lists the key current risk factors as of the date of this filing that may have a direct and material impact on our business, financial position, results of operations and cash flows.

Risks Relating to Our Business

Our operating cash flow is derived primarily from cash distributions we receive from EPO.

Our operating cash flow is derived primarily from cash distributions we receive from EPO (which includes the cash distributions that EPO receives from Energy Transfer Equity). As discussed below, the amount of cash that EPO and Energy Transfer Equity can distribute principally depends upon the amount of cash flow they generate from their respective operations, which will fluctuate from quarter-to-quarter based on, among other things, the:

§ volume of hydrocarbon products transported in its gathering and transmission pipelines;

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- throughput volumes in its processing and treating operations;
- fees it charges and the margins it realizes for its various storage, terminaling, processing and transportation services;
- price of natural gas, crude oil and NGLs;
- relationships among natural gas, crude oil and NGL prices, including differentials between regional markets;
- fluctuations in its working capital needs;
- level of its operating costs, including, in the case of Energy Transfer Equity, reimbursements to its general partner;
- prevailing economic conditions; and
- level of competition in its business segments and market areas.

In addition, the actual amount of cash each of EPO and Energy Transfer Equity will have available for distribution will depend on other factors, including:

- the level of sustaining capital expenditures incurred;
- its cash outlays for capital projects and acquisitions;
- its debt service requirements and restrictions contained in its obligations for borrowed money; and
- the amount of cash reserves required by us and Energy Transfer Equity for the normal conduct of EPO's and Energy Transfer Equity's businesses, respectively.

We do not have any direct or indirect control over the cash distribution policies of Energy Transfer Equity made by its general partner.

Because of these factors, we and Energy Transfer Equity may not have sufficient available cash each quarter to continue paying distributions at our and their current levels. Furthermore, the amount of cash that each of we and Energy Transfer Equity has available for cash distribution depends primarily upon our and its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. As a result, each of Energy Transfer Equity and us may be able to make cash distributions during periods when we respectively record losses and may not be able to make cash distributions during periods when we respectively record net income.

See below for a discussion of further risks affecting our ability to generate distributable cash flow. These risks also generally apply to Energy Transfer Equity as they operate in our industry.

Changes in demand for and production of hydrocarbon products may materially adversely affect our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil and refined products. As such, our financial position, results of operations and cash flows may be materially adversely affected by changes in the prices of hydrocarbon products and by changes in the relative price levels among hydrocarbon products. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we provide services. We may also incur credit and

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price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil.

Historically, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu. In 2010, the same index ranged from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu.

Generally, the prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional uncontrollable factors. Some of these factors include:

§ the level of domestic production and consumer product demand;

§ the availability of imported oil and natural gas and actions taken by foreign oil and natural gas producing nations;

§ the availability of transportation systems with adequate capacity;

§ the availability of competitive fuels;

§ fluctuating and seasonal demand for oil, natural gas and NGLs;

§ the impact of conservation efforts;

§ the extent of governmental regulation and taxation of production; and

§ the overall economic environment.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect our financial position, results of operations and cash flows. Volatility in commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us.

With respect to our Petrochemical & Refined Products Services segment, market demand and our revenue from these businesses can also be adversely affected by different end uses of the products we transport, market or store. For example:

§ demand for gasoline depends upon market price, prevailing economic conditions, demographic changes in the markets we serve and availability of gasoline produced in refineries located in these markets;

§ demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities that use distillates as a substitute and usage for agricultural operations;

§ demand for jet fuel depends on prevailing economic conditions and military usage; and

§ propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

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A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our financial position, results of operations and cash flows.

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

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties. Many economic and business factors are beyond our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistic assets are located could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our financial position, results of operations and cash flows.

In addition, imported liquefied natural gas ("LNG") may become a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies may be imported through new LNG facilities that have currently been developed or new LNG facilities that have been announced to be developed over the next decade. We cannot predict which, if any, of these announced, but as yet unbuilt, projects will be constructed. In addition, anticipated increases in future natural gas supplies may not be made available to our facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to our assets or (iv) they do not influence sources of supply on our systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on our pipelines would decline, which could have a material adverse effect on our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our financial position, results of operations and cash flows. Decreases in such demand may be caused by general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane could be reduced.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

We face competition from third parties in our midstream energy businesses.

Even if crude oil and natural gas reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Our refined products, NGL and marine transportation businesses compete with other pipelines and marine transportation companies in the areas they serve. We also compete with trucks and railroads in some of the areas we serve. Substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business. Competitive pressures may adversely affect our tariff rates or volumes shipped.

The crude oil gathering and marketing business can be characterized by thin operating margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production has intensified competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies, financial institutions with trading platforms and other companies in the areas where such pipeline systems deliver crude oil and NGLs.

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and price arrangements. Our key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems. If production delivered to our gathering system declines, our revenues from such operations will decline.

Our debt level may limit our future financial and operating flexibility.

As of December 31, 2010, we had approximately $12.0 billion principal amount of consolidated senior long-term debt outstanding and approximately $1.53 billion principal amount of junior subordinated debt outstanding. This amount includes (i) $1.1 billion of debt we incurred in the Holdings merger through the refinancing of Holdings' revolving credit facility and term loans with additional borrowings under EPO's revolving credit facility and (ii) $788.3 million outstanding under Duncan Energy Partners' multi-year revolving credit facility and term loans. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a substantial portion of our cash flow, including that of Duncan Energy Partners, could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

§ credit rating agencies may view our consolidated debt level negatively;

§ covenants contained in our existing and future credit and debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

§ our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

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

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

Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Although our credit agreements restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding our credit facilities, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our credit agreements and each of our indentures for our public debt contain conventional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under our credit agreements. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of our credit agreements, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term securities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our growth strategy contemplates the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We consider and pursue potential joint ventures, standalone projects or other transactions that we believe may present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise necessary funds on satisfactory terms, if at all.

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Tightening of the credit markets in the future may have a material adverse effect on us by, among other things, decreasing our ability to finance expansion projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of new equity issued may be at a higher yield than our historical levels, making additional equity issuances more expensive.

We also compete for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our variable-rate debt and future maturities of fixed-rate, long-term debt make us vulnerable to increases in interest rates, which could materially adversely affect our business, financial position, results of operation and cash flows.

As of December 31, 2010, we had outstanding $13.53 billion principal amount of consolidated debt. Of this amount, approximately $1.44 billion, or 11%, was subject to variable interest rates, either as long-term variable-rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. In 2011, 2012, 2013, 2014 and 2015, we have $450.0 million, $1.0 billion, $1.2 billion, $1.15 billion and $650.0 million, respectively, of senior notes maturing. In addition, our $1.75 billion revolving credit facility matures in 2012, Duncan Energy Partners' $282.3 million term loan matures in 2011 and Duncan Energy Partners' remaining debt obligations mature in 2013.

The rate on our May 2010 issuance of $400.0 million of Senior Notes due June 2015 was 3.7%. The rate on our May 2010 issuance of $1.0 billion of Senior Notes due September 2020 was 5.2%, and the rate on our May 2010 issuance of $600.0 million of Senior Notes due September 2040 was 6.45%. Should interest rates increase significantly, the amount of cash required to service our debt would increase. As a result, our financial position, results of operations and cash flows, could be materially adversely affected.

From time to time, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, our financial position, results of operations and cash flows could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

Operating cash flows from our capital projects may not be immediate.

We have announced and are engaged in several construction projects involving existing and new facilities for which we have expended or will expend significant capital, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and we may not receive any material increase in operating cash flow from that project until a period of time after it is placed in-service. If we experience any unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

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Our growth strategy may adversely affect our results of operations if we do not successfully integrate and manage the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses (either ourselves or Duncan Energy Partners may do so) that we believe complement our existing operations. We may be unable to successfully integrate and manage businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our financial position, results of operations and cash flows. Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

§ establishing the internal controls and procedures that we are required to maintain under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have not previously partnered;

§ experiencing unforeseen operational interruptions or the loss of key employees, customers or suppliers;

§ inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

§ diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, amortization and accretion expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

Acquisitions that appear to increase our cash from operations may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will increase our cash from operations, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves assumptions that may not materialize and potential risks that may occur. These risks include our inability to achieve our operating and financial projections or to integrate an acquired business successfully, the assumption of unknown liabilities for which we become liable and the loss of key employees or key customers.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

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Our actual construction, development and acquisition costs could exceed forecasted amounts.

We have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Gustav and Ike in 2008.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

§ we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

§ we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

§ we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;

§ since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

§ where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves;

§ the completion or success of our project may depend on the completion of a project that we do not control, such as a refinery, that may be subject to numerous of its own potential risks, delays and complexities; and

§ we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

A significant amount of our common units and all of our Class B units that are owned by EPCO and certain of its affiliates are pledged as security under the credit facility of an affiliate of EPCO. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged a significant amount of its common units and all of its Class B units in us as security under its credit facility. This credit facility contains customary and other events of default relating to defaults of the borrower and certain of its affiliates, including us. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of us.

The credit and risk profile of owners of our general partner and their privately-held affiliates could adversely affect our risk profile, which could increase our borrowing costs, hinder our ability to raise capital or impact future credit ratings.

The credit and business risk profiles of the owners of our general partner and their privately-held affiliates may be factors in credit evaluations of our master limited partnership. This is because the general partner can exercise significant influence over the business activities of our partnership, including its cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of owners of our general partner and their privately-held affiliates, including the degree of their financial leverage and their dependence on cash flow from our partnership to service their indebtedness.

Affiliates of the entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to creditors.

Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours.

The interruption of cash distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make cash distributions to our partners.

We are a holding company with no business operations, and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our operating subsidiary, EPO. As a result, we depend upon the earnings and cash flow of EPO and its subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make cash distributions to our partners. The ability of EPO and its subsidiaries and joint ventures to make cash distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

As of December 31, 2010, EPO also owned 33,783,587 common units of Duncan Energy Partners, representing approximately 58.5% of its outstanding common units and 100% of its general partner. EPO also owned noncontrolling interests in subsidiaries of Duncan Energy Partners that held total assets of approximately $5.56 billion as of December 31, 2010. With respect to three subsidiaries of Duncan Energy Partners acquired from us on December 8, 2008 that held approximately $3.87 billion of total assets as of December 31, 2010, Duncan Energy Partners has effective priority rights to specified quarterly distribution amounts ahead of distributions on our retained equity interests in these subsidiaries.

In addition, the charter documents governing EPO's joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Three of the joint ventures in which EPO participates have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make cash distributions to us under certain circumstances. Accordingly, EPO's joint ventures may be unable to make cash distributions to us at current levels, if at all.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in us being required to partner with different or additional parties.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 lbs per square inch. We also operate crude oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. In addition, our marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events. From time to time, our octane enhancement facility may produce MTBE for export, which could expose us to additional risks from spill events. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk.

If one or more facilities that we own or that deliver crude oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market

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conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, change in the insurance markets subsequent to the hurricanes in 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2010, our balance sheet reflected $2.11 billion of goodwill and $1.84 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States (“GAAP”) require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate non-cash charge to earnings with a correlative effect on partners’ equity and balance sheet leverage as measured by debt to total capitalization.

The use of derivative financial instruments could result in material financial losses by us.

We historically have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed. Adverse economic conditions, such as the financial crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment or performance by our hedging counterparties. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for a discussion of our derivative instruments.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment and nonperformance by customers, particularly for customers that are smaller companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Our consolidated revenues are derived from a wide customer base. During 2010 and 2009, our largest non-affiliated customer was Shell, which

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accounted for 9.4% and 9.8% of our consolidated revenues, respectively. During 2008, our largest non-affiliated customer was Valero, which accounted for 11.2% of our consolidated revenues.

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

To enhance utilization of certain assets and our operating income, we purchase petroleum products. Generally, it is our policy to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to establish a margin for the commodity purchased by selling the same commodity for physical delivery to third-party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product inventory, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity on our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved.

Our pipeline integrity program and periodic tank maintenance requirements may impose significant costs and liabilities on us.

The DOT issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline’s integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

In June 2008, the DOT issued a Final Rule extending its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around “unusually sensitive areas.” The issuance of these new gathering and low-stress pipeline safety regulations, including requirements for integrity management of those pipelines, is likely to increase the operating costs of our pipelines subject to such new requirements.

The American Petroleum Institute Standard 653 (“API 653”) is an industry standard for the inspection, repair, alteration and reconstruction of existing storage tanks. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Periodic tank maintenance requirements could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

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Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows.

On April 20, 2010, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill that has significantly impacted ecological resources in the Gulf of Mexico. As a result, on May 28, 2010, the U.S. Department of the Interior issued a six-month moratorium that halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. In addition to the moratorium, the Department of the Interior also canceled or delayed offshore oil and gas lease sales off the Mid-Atlantic coast and in Alaska. The Interior Secretary withdrew the moratorium and replaced it on July 12, 2010 with a suspension of certain offshore drilling activities that was to be effective through October 30, 2010.

The drilling suspension was lifted by the Interior Secretary on October 12, 2010. However, the timing and process for approving applications for new permits to drill and the cost associated with compliance with various new and enhanced safety and environmental requirements (discussed below) imposed following the Deepwater Horizon incident remain uncertain. The Interior Department has indicated that it will not issue drilling permits until well operators demonstrate that safety and environmental protection requirements for offshore exploration and production can be met, and it is unclear what actions will satisfy the new safety and environmental requirements.

Following the Deepwater Horizon incident, the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), formerly the Minerals Management Service, an office of the Department of the Interior which is charged with oversight of the United States' oil, natural gas and other minerals on the Outer Continental Shelf has been reorganized. The BOEMRE, has issued a series of rules that increase regulatory requirements for offshore oil and gas operations. On June 8, 2010, the BOEMRE issued a notice to holders of offshore oil and gas leases requiring compliance certifications and third party verification of certain inspection and design matters. On June 18, 2010, a subsequent notice to lessees called for enhanced information regarding planning scenarios relating to blowouts, discharges of pollutants and prevention of accidents. Another notice to lessees on August 16, 2010, made changes to the environmental review process for offshore oil and gas development. On October 14, 2010, the BOEMRE published an emergency drilling safety rule imposing additional requirements for well bore integrity and well control equipment and procedures, including provisions addressing blowout preventers and the use of drilling fluids. This interim final rule became effective immediately, but is subject to future changes that may be made by the BOEMRE in response to public comments. On October 14, 2010, the BOEMRE also published a final rule requiring safety and environmental management systems for all oil and gas operations on the Outer Continental Shelf. On November 8, 2010, the BOEMRE issued a notice to lessees requiring certifications and a demonstration that the well operator has access to and can deploy containment resources adequate to respond to a blow out or other loss of well control. In addition to federal regulatory activity, at least one state has ordered enhanced inspections of oil and gas rigs and required more stringent disaster preparedness plans, and it is possible that other state-level requirements will be imposed on offshore energy production activities.

Accordingly, the effect of new regulatory requirements on offshore energy development in the Gulf of Mexico following the Deepwater Horizon incident, including the prospects and timing of securing permits for offshore energy production activities, are evolving and uncertain. Such uncertainty may cause companies to curtail or delay oil and gas drilling activities, or to redirect resources to other areas such as West Africa, the Caribbean or South America, which may further delay the resumption of drilling activity in the Gulf of Mexico. It is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected.

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In addition to federal agency action, numerous legislative proposals were introduced in the last U.S. Congress in reaction to the Deepwater Horizon incident, some of which may be considered in the current legislative session. Bills that have received attention include measures to:

- modify or revoke liability limits and caps under the Oil Spill Liability Trust Fund, the Oil Pollution Act of 1990, and certain other statutes;
- revise federal liability regimes to include health effects, personal injuries, and other tort claims;
- mandate more stringent safety measures and inspections under the Oil Pollution Act and Outer Continental Shelf Lands Act;
- expand environmental reviews and lengthen review timelines;
- impose fees, increase taxes or remove tax exemptions;
- modify financial responsibility and insurance requirements for offshore energy activities; and
- require U.S. registration of oil rigs.

However, it is unclear and cannot be predicted whether and when Congress may pass legislation.

Given the scope and effect of the Deepwater Horizon incident to date, as well as statements made by the Interior Secretary, it is expected that additional regulatory compliance and agency review will be required prior to permitting new wells or continued drilling of existing wells, which may affect the cost and timing of oil and gas drilling in the Gulf of Mexico and other offshore areas. A decline in, or failure to achieve anticipated volumes of, oil and natural gas supplies due to any of the foregoing factors may have a material adverse effect on our financial position, results of operations or cash flows through reduced gathering and transportation volumes, processing activities, or other midstream services.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could materially affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce the emissions of greenhouse gases, will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate Change Risks

Climate change regulation is one area of potential future environmental law development. Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, 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. Among these, 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 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 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.

The EPA has also taken action under the CAA to regulate greenhouse gas emissions. On November 8, 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 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. 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.

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, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. 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.

Moreover, 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 contribute 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

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remains pending before the United States Court of Appeals for the Ninth Circuit. These cases could establish legal precedent that may expose other significant emission sources of greenhouse gases to similar litigation risk.

These or any future developments, may have an adverse effect on our business, financial position results of operations and cash flows. 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 legislation.

In addition, global warming could have an impact on our physical operations and energy markets. 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 from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase or decrease the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix.

Hydraulic Fracturing Risks

Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act (“SDWA”) to exclude hydraulic fracturing from the definition of “underground injection” under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Similar legislation could be introduced in the current session of Congress, which commenced in January 2011. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available by late 2012. Last year, a committee of the U.S. House of Representatives commenced investigations into hydraulic fracturing practices. The U.S. Department of the Interior has announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. For example, New York has imposed a de facto moratorium on the issuance of permits for certain hydraulic fracturing practices until an environmental review and potential new regulations are finalized, which will at the earliest be July 31, 2011. Significant controversy has surrounded drilling operations in Pennsylvania. Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process, and Colorado requires recordkeeping and disclosure of fracturing fluid constituents to officials in certain circumstances. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas including from the developing shale plays incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and our results of operations, cash flows and financial position could be materially impacted.

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Marine Transportation Risks

Our marine transportation operations are also subject to state and local laws and regulations that control the discharge of pollutants into the environment or otherwise relate to environmental protection. Compliance with such laws, regulations and standards may require installation of costly equipment or operational changes. Failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our marine operations. Some environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject us to liability without regard to whether we were negligent or at fault. Under the OPA, owners, operators and bareboat charterers are jointly and severally strictly liable for the discharge of oil within the internal and territorial waters of, and the 200-mile exclusive economic zone around, the United States. Additionally, an oil spill from one of our vessels could result in significant liability, including fines, penalties, criminal liability and costs for natural resource damages. The potential for these releases could increase if we increase our fleet capacity. In addition, most states bordering on a navigable waterway have enacted legislation providing for potentially unlimited liability for the discharge of pollutants within their waters.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial position.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the NGA, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that our services are provided on a non-discriminatory basis so that all shippers have open access to our pipelines and storage. Pursuant to the FERC’s jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC and proposed rate increases may be challenged by protest.

We have interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the DOT’s OPS under the Natural Gas Pipeline Safety Act.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

Although our natural gas gathering systems are generally exempt from FERC regulation under the NGA, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, our natural gas gathering operations could be adversely affected in the future should they become subject to the application of federal regulation of rates and services or if the states in which we operate adopt policies imposing more onerous regulation on gathering. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

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Increasingly stringent federal, state and local laws and regulations governing worker health and safety and the manning, construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine industry are subject to extensive governmental regulation by the USCG, the DOT, the Department of Homeland Security, the National Transportation Safety Board and the U.S. Customs and Border Protection, and to regulation by private industry organizations such as the ABS. The USCG and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The USCG is authorized to inspect vessels at will.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulation" included within Items 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to unitholders.

The workplaces associated with our facilities are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could expose us to liability, enforcement, and fines and penalties, and could have a material adverse effect on our business, financial position, results of operations and ability to make distributions to unitholders.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The United States Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). The Dodd-Frank Act provides for new statutory and regulatory requirements for financial derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Dodd-Frank Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. The Dodd-Frank Act requires the Commodity Futures Trading Commission (the "CFTC") to promulgate rules to define these terms in detail, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

The majority of our financial derivative transactions are currently executed and cleared over exchanges that already require the posting of cash collateral or letters of credit based on initial and variation margin requirements. We enter into over-the-counter natural gas, NGL, crude oil and refined products derivative contracts from time to time with respect to a portion of our expected processing, storage and transportation activities in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from these activities. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide additional cash collateral for our commodities hedging transactions whether cleared over an exchange or new cash collateral for those transactions executed over-the-counter. Posting of additional or new cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post additional or new cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our over-the-counter derivative hedging contracts that do not increase the amount of cash collateral posted for transactions cleared over an exchange. In addition, even if we ourselves are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Dodd-Frank Act's new requirements, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

Our rates are subject to review and possible adjustment by federal and state regulators, which could have a material adverse effect on our financial position and results of operations.

The FERC, pursuant to the ICA, as amended, the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under the ICA, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with the FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. The FERC also can order reparations for overcharges effective two years prior to the date of a complaint. Due to the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, Market-Based Rates or agreements with all of the pipeline's shippers that the rate is acceptable. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates, or challenges to our application of that methodology, could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Our partnership status may be a disadvantage to us in calculating our cost of service for rate-making purposes.

In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owner of its interests has an actual or potential income tax liability on such income. The policy statement also provides that whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In December 2005, the FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership's rate case. The FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16, 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). The D.C. Circuit denied these appeals in May 2007 and fully upheld the FERC's new tax allowance policy and the application of that policy in the December 2005 order.

In December 2006, the FERC issued a new order addressing rates on another pipeline. In the new order, FERC refined its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of

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a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which the FERC characterized as a "tax savings." The FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, the FERC chose to adjust the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income.

In April 2008, the FERC issued a Policy Statement in which it declared that it would permit master limited partnerships ("MLPs") to be included in rate of return proxy groups for determining rates for services by natural gas and oil pipelines. It also addressed the application to limited partnership pipelines of the FERC's discounted cash flow methodology for determining rates of return on equity. The FERC applied the new policy to several ongoing proceedings involving other pipelines. The FERC's rate of return policy remains subject to change.

The ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service as well as rates of return, particularly with respect to pipelines organized as partnerships. The outcome of these ongoing proceedings could adversely affect our revenues for any of our rates that are calculated using cost of service rate methodologies.

Our marine transportation business would be adversely affected if we failed to comply with the Jones Act provisions on coastwise trade, or if those provisions were modified, repealed or waived.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between points in the United States to vessels built and registered in the United States and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common units and other partnership interests. If we do not comply with these restrictions, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels.

In the past, interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes currently reserved for U.S.-flag vessels under the Jones Act and cargo preference laws. We believe that interest groups may continue efforts to modify or repeal the Jones Act and cargo preference laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could reduce our revenues and cash available for distribution.

The Secretary of the Department of Homeland Security is vested with the authority and discretion to waive the coastwise laws to such extent and upon such terms as he may prescribe whenever he deems that such action is necessary in the interest of national defense. For example, in response to the effects of Hurricanes Katrina and Rita, the Secretary of the Department of Homeland Security waived the coastwise laws generally for the transportation of petroleum products from September 1 to September 19, 2005 and from September 26, 2005 to October 24, 2005. In the past, the Secretary of the Department of Homeland Security has waived the coastwise laws generally for the transportation of petroleum released from the Strategic Petroleum Reserve undertaken in response to circumstances arising from major natural disasters. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign marine vessel operators, which could reduce our revenues and cash available for distribution.

We depend on the leadership and involvement of key personnel for the success of our businesses.

We depend on the leadership, involvement and services of key personnel. The loss of leadership and involvement or the services of certain key members of our senior management team could have a material adverse effect on our business, financial position, results of operations, cash flows and market price of our securities.

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EPCO's employees may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping officers and employees allocate their time among us, EPCO and other affiliates of EPCO. These officers and employees face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial position.

We have entered into an ASA, which governs business opportunities among entities controlled by EPCO, which includes us and our general partner and Duncan Energy Partners and its general partner. For detailed information regarding how business opportunities are handled within the EPCO group of companies, see Item 13 of this annual report.

We do not have a separate compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us. For a discussion of our executive compensation policies and procedures, see Item 11 of this annual report.

The global financial crisis and its ongoing effects may have impacts on our business and financial position that we currently cannot predict.

We may face significant challenges if conditions in the financial markets revert to those that existed from the fourth quarter of 2008 through 2009. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for our services and products. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

§ the ownership interest of a unitholder immediately prior to the issuance will decrease;

§ the amount of cash available for distributions on each common unit may decrease;

§ the ratio of taxable income to distributions may increase;

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

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§ the market price of our common units may decline.

We may not have sufficient cash from operations to pay cash distributions at the current level following establishment of cash reserves and payments of fees and expenses.

Because cash distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance and capital needs. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include but are not limited to the following:

§ the volume of the products that we handle and the prices we receive for our services;

§ the level of our operating costs;

§ the level of competition in our business segments and marketing areas;

§ prevailing economic conditions, including the price of and demand for oil, natural gas and other products we transport, store and market;

§ the level of capital expenditures we make;

§ the amount and cost of capital we can raise compared to the amount of our capital expenditures and debt maturities;

§ the restrictions contained in our debt agreements and our debt service requirements;

§ fluctuations in our working capital needs;

§ the weather in our operating areas;

§ cash outlays for acquisitions, if any; and

§ the amount, if any, of cash reserves required by our general partner in its sole discretion.

In addition, you should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per common unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner may be substantial and will reduce our cash available for distribution our unitholders.

Prior to making any distribution on our common units, we will reimburse EPCO and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our units. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

Our general partner and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of our general partner and its affiliates have duties to manage our general partner in a manner that is beneficial to its members. At the same time, our general partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our general partner’s duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

§ neither our partnership agreement nor any other agreement requires our general partner or EPCO to pursue a business strategy that favors us;

§ decisions of our general partner regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders;

§ under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

§ our general partner is allowed to resolve any conflicts of interest involving us and our general partner and its affiliates;

§ our general partner is allowed to take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;

§ any resolution of a conflict of interest by our general partner not made in bad faith and that is fair and reasonable to us shall be binding on the partners and shall not be a breach of our partnership agreement;

§ affiliates of our general partner may compete with us in certain circumstances;

§ our general partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

§ we do not have any employees and we rely solely on employees of EPCO and its affiliates;

§ in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions;

§ our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

§ our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

§ our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

§ our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by EPCO and Dan Duncan LLC. For detailed information on these relationships and related transactions with these entities, see Item 13 of this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Because affiliates of our general partner currently own approximately 39.9% of our outstanding common units, the removal of our general partner as our general partner is highly unlikely without the consent of both our general partner and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

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

If at any time our general partner and its affiliates own 85% or more of the common units then outstanding, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their common units.

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Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business. Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

§ we were conducting business in a state, but had not complied with that particular state's partnership statute; or

§ your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third-party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third-party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the sole member of our general partner to transfer its equity interests in our general partner to a third-party. The new equity owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to influence the decisions taken by the board of directors and officers of our general partner.

Risks Relating to Our Ownership of Energy Transfer Equity and Affiliates

We may have to take actions that are disruptive to our business strategy to avoid registration under the Investment Company Act of 1940.

The Investment Company Act of 1940, or Investment Company Act, requires registration for companies that are engaged primarily in the business of investing, reinvesting, owning, holding or trading

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in securities. Registration as an investment company would subject us to restrictions that are inconsistent with our fundamental business strategy.

A company may be deemed to be an investment company if it owns investment securities with a fair value exceeding 40% of the fair value of its total assets (excluding governmental securities and cash items) on an unconsolidated basis, unless an exemption or safe harbor applies. Securities issued by companies other than majority-owned subsidiaries are generally counted as investment securities for purposes of the Investment Company Act. We own noncontrolling equity interests in Energy Transfer Equity that could be counted as investment securities. In the event we acquire additional investment securities in the future, or if the fair value of our interests in companies that we do not control were to increase relative to the fair value of our controlled subsidiaries (e.g., Duncan Energy Partners), we might be required to divest some of our non-controlled business interests, or take other action, in order to avoid being classified as an investment company. Similarly, we may be limited in our strategy to make future acquisitions of general partner interests and related limited partner interests to the extent they are counted as investment securities.

If we cease to manage and control Duncan Energy Partners and are deemed to be an investment company under the Investment Company Act of 1940, we may either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC, or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment compan