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

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

FORM 10-K

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

For the fiscal year ended December 31, 2010

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

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

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

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

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

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

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

Securities to be registered pursuant to Section 12(g) of the Act: None.

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o

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

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

Large accelerated filer þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

1

Table of Contents

SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

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

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

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

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

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

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

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

Ms. Williams is currently the Duncan Voting Trustee.

Table of Contents

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

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

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

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

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

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

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

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their

Table of Contents

mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

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

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

Table of Contents

PART I

Items 1 and 2. Business and Properties.

General

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

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

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

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

Business Strategy

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

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

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

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

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

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

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

Table of Contents

Offer to Acquire Duncan Energy Partners

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

Holdings Merger

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

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

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

Basis of Presentation

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

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE: EPE) electronically filed its annual and quarterly consolidated financial statements with the U.S. Securities and Exchange Commission. You can access this information at www.sec.gov.

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

Significant Growth Capital Projects

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

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

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

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

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

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

Table of Contents

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

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

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

Segment Discussion

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

§ NGL Pipelines & Services;

§ Onshore Natural Gas Pipelines & Services;

§ Onshore Crude Oil Pipelines & Services;

§ Offshore Pipelines & Services;

§ Petrochemical & Refined Products Services; and

§ Other Investments.

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

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

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

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

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

Table of Contents

Financial Information by Business Segment

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

NGL Pipelines & Services

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

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

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

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

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer’s natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers’ natural gas. Under a percent-of-liquids contract, the producer retains title to a percentage of the mixed NGLs we extract and generally bears the cost of natural gas associated with shrinkage and plant fuel. The value of natural gas lost as a result of NGL extraction (i.e., shrinkage) and consumed as plant fuel is referred to as plant thermal reduction ("PTR"). Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

12

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Onshore Natural Gas Pipelines & Services

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Onshore Crude Oil Pipelines & Services

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

Offshore Pipelines & Services

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

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

28

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.

§ 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

Other Investments

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

Title to Properties

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

Regulation

Interstate Pipelines

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

40

Table of Contents

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

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

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

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

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

Intrastate Pipelines

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

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

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

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

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

Sales of Natural Gas

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

Table of Contents

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

Marine Operations

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

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

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

Table of Contents

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

Environmental and Safety Matters

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

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

Air Emissions

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

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

Table of Contents

Climate Change Regulation

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

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

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

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

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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 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;

50

Table of Contents

- 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 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.

Table of Contents

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

Table of Contents

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;

54

- § 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.

Table of Contents

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.

Table of Contents

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.

57

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

62

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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

§ 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

Table of Contents

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;

Table of Contents

§ 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.

Table of Contents

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 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 company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to our unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions available for distribution to unitholders would be substantially reduced. As a result, treatment of us as an investment company would result in a material reduction in distributions to our unitholders, which would materially reduce the value of our common units.

A reduction in ETP’s distributions will disproportionately affect the amount of cash distributions to which Energy Transfer Equity and we are entitled.

Energy Transfer Equity’s indirect ownership of 100% of the IDRs in ETP, through its ownership of equity interests in the general partner of ETP, the holder of the IDRs, entitles Energy Transfer Equity to receive its pro rata share of specified percentages of total cash distributions made by ETP as it reaches established target cash distribution levels. Energy Transfer Equity currently receives its pro rata share of cash distributions from ETP based on the highest incremental percentage, 48%, to which the general partner of ETP is entitled pursuant to its IDRs in ETP. A decrease in the amount of distributions by ETP to less than $0.4125 per ETP common unit per quarter would reduce the general partner of ETP’s percentage of the incremental cash distributions above $0.3175 per ETP common unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from ETP would have the effect of disproportionately reducing the amount of all distributions that Energy Transfer Equity receives from ETP based on its ownership interest in the IDRs in ETP as compared to cash distributions Energy Transfer Equity receives from ETP on its general partner interest in ETP (representing a 1.8% interest as of December 31, 2010) and its ETP common units. Any such reduction would reduce the amounts that Energy Transfer Equity could distribute to us directly and indirectly through our equity interests in its general partner.

76

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends to an extent on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter. The value of our investment in Energy Transfer Equity and Duncan Energy Partners (the "MLP Entities") depends largely on each of the MLP Entities being treated as a partnership for federal income tax purposes.

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

If either of the MLP Entities were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate and would likely pay state income taxes at varying rates. Distributions to us would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to us. As a result there would be a material reduction in our anticipated cash flow, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us or either of the MLP Entities to be treated as a corporation for federal income tax purposes or otherwise subjecting us or either of the MLP Entities to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to enhance state-tax collections. If any additional state were to impose an entity-level tax upon us, our operating subsidiaries or the MLP Entities, the cash available for distribution to our unitholders would be reduced.

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

The present federal income tax treatment of publicly traded partnerships, including us and the MLP Entities, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception, which we refer to as the qualifying income exception, for us to be treated as a partnership for federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income or adversely affect an investment in our common units. Recently, members of Congress considered substantive changes to the existing U.S. tax laws that would have affected the tax treatment of certain publicly traded partnerships. In addition, President Obama's Fiscal Year 2012 Budget Proposal includes provisions that would, if enacted, change the treatment of certain types of income earned from profits or "carried" interests. We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

Table of Contents

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of the common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount from the cash that we distribute, our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

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

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder’s tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit, which decreased the unitholder’s tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder’s tax basis in that common unit, even if the price the unitholder receives is less than the unitholder’s original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

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

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

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

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

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

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we or each of the MLP Entities do business or own property even if the unitholder does not live in any of those jurisdictions. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We or the MLP Entities may own property or conduct business in other states or foreign countries in the future. It is the responsibility of each unitholder to file its own federal, state and local tax returns.

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in us filing two tax returns (and our unitholders could receive two Schedule K-1s) for one fiscal year. A technical termination could also result in the deferral of depreciation deductions allowable in computing our taxable income.

The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax years in which the technical termination occurs.

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

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

Table of Contents

of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

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

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

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our consolidated financial position, results of operations or cash flows. For information regarding our significant legal proceedings, see "Litigation" under Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which subsection is incorporated by reference into this Item 3.

Item 4. (Removed and Reserved).

80

Table of Contents

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

Market Information and Cash Distributions for Enterprise

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 1, 2011, there were approximately 1,916 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods presented (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to such periods. Actual cash distributions are paid by us within 45 days after the end of each fiscal quarter.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2009					
1st Quarter	$24.200	$17.710	$0.5375	Apr. 30, 2009	May 8, 2009
2nd Quarter	$26.550	$21.100	$0.5450	Jul. 31, 2009	Aug. 7, 2009
3rd Quarter	$29.450	$24.500	$0.5525	Oct. 30, 2009	Nov. 5, 2009
4th Quarter	$32.240	$27.250	$0.5600	Jan. 29, 2010	Feb. 4, 2010
2010					
1st Quarter	$34.690	$29.440	$0.5675	Apr. 30, 2010	May 6, 2010
2nd Quarter	$36.730	$29.050	$0.5750	Jul. 30, 2010	Aug. 5, 2010
3rd Quarter	$39.690	$34.210	$0.5825	Oct. 29, 2010	Nov. 8, 2010
4th Quarter	$44.320	$39.260	$0.5900	Jan. 31, 2011	Feb. 7, 2011

We expect to fund our quarterly cash distributions to common unitholders primarily with cash provided by operating activities. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

As discussed under "Noncontrolling Interest" within Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, the cash distributions paid by Enterprise to its limited partners other than Holdings prior to the Holdings Merger are a component of noncontrolling interest. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report.

Recent Sales of Unregistered Securities

On September 30, 2010, we issued 523,306 of our unregistered common units to EPCO in exchange for all of EPCO's ownership interest in ETC. The equity consideration we issued was based on the average closing price of our common units over a 20-day period ending September 28, 2010. Because the issuance was to an affiliate and did not involve any public offering, the issuance of these common units was exempt from registration by Section 4(2) of the Securities Act of 1933, as amended.

On November 1, 2010, we issued 2,329,639 of our unregistered common units to Cenac Towing Co., L.L.C., Cenac Offshore, L.L.C., CTCO Marine Services, LLC, and CTCO Shipyard of Louisiana, LLC in exchange for certain assets relating to their shipyard operations in Louisiana and certain membership interests in CTCO of Texas, L.L.C. and Channelview Fleeting Services, LLC relating to shipyard operations in Texas. Because the issuance did not involve any public offering, the issuance of these common units was exempt from registration by Section 4(2) of the Securities Act of 1933, as amended.

Other than as described above, there were no sales of unregistered equity securities during 2010.

Table of Contents

Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). We have not repurchased any of our common units under this program since 2002. As of February 1, 2011, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

The following table summarizes our repurchase activity during 2010 in connection with other arrangements:

Period	Total Number of Units Purchased	Weighted-Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2010 (1)	7,480	$ 32.17	--	--
May 2010 (2)	78,522	$ 35.60	--	--
August 2010 (3)	2,621	$ 37.74	--	--
November 2010 (4)	13,516	$ 42.68	--	--
December 2010 (5)	1,102	$ 40.82	--	--

(1) Of the 34,528 restricted common units that vested in February 2010 and converted to common units, 7,480 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 287,700 restricted common units that vested in May 2010 and converted to common units, 78,522 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 17,400 restricted common units that vested in August 2010 and converted to common units, 2,621 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 44,000 restricted common units and 8,333 phantom units that vested in November 2010 and converted to common units, 13,516 units were sold back to us by employees to cover related withholding tax requirements.
(5) Of the 4,166 phantom units that vested in December 2010 and converted to common units, 1,102 units were sold back to us by employees to cover related withholding tax requirements.

Table of Contents

Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial data of our partnership. As a result of the Holdings Merger, our consolidated financial and operating results prior to November 22, 2010 have been presented as if we were Holdings from an accounting perspective. This information has been derived from and should be read in conjunction with the audited financial statements included under Item 8 of this annual report. Additional information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts are in millions (except per unit data).

	For Year Ended December 31,				
	2010	2009	2008	2007	2006
Results of operations data: (1)					
Revenues	$ 33,739.3	$ 25,510.9	$ 35,469.6	$ 26,713.8	$ 23,612.2
Income from continuing operations (2)	$ 1,383.7	$ 1,140.3	$ 1,145.1	$ 762.0	$ 772.4
Net income	$ 1,383.7	$ 1,140.3	$ 1,145.1	$ 762.0	$ 772.4
Net income attributable to partners	$ 320.8	$ 204.1	$ 164.0	$ 109.0	$ 134.0
Earnings per unit:					
Basic (3)	$ 1.17	$ 0.99	$ 0.89	$ 0.65	$ 0.87
Diluted (3)	$ 1.15	$ 0.99	$ 0.89	$ 0.65	$ 0.87
Other financial data:					
Cash distributions per unit (4)	$ 2.27	$ 2.03	$ 1.79	$ 1.55	$ 1.29

	As of December 31,				
	2010	2009	2008	2007	2006
Financial position data: (1)					
Total assets	$ 31,360.8	$ 27,686.3	$ 25,780.4	$ 24,084.4	$ 19,120.1
Long-term and current maturities of debt (5)	$ 13,563.5	$ 12,427.9	$ 12,714.9	$ 9,861.2	$ 7,053.9
Equity (6)	$ 11,900.8	$ 10,473.1	$ 9,759.4	$ 9,530.0	$ 8,968.7
Total units outstanding (7)	843.7	208.8	184.8	168.5	154.7

(1) In general, our historical results of operations and financial position have been affected by business combinations, asset acquisitions and other capital spending. In May 2007, Holdings acquired noncontrolling interests in Energy Transfer Equity. For information regarding our significant business combinations during the years ended December 31, 2010, 2009 and 2008, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(2) Amounts presented are before the cumulative effect of a change in accounting principle in 2006.
(3) Earnings per unit for the periods presented have been retroactively presented in connection with the Holdings Merger. For information regarding our earnings per unit amounts for the years ended December 31, 2010, 2009 and 2008, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(4) Distributions per unit for 2010 are calculated based on Holdings' cash distributions per unit prior to the Holdings Merger (i.e., for the first, second and third quarters of 2010) and Enterprise's declared cash distribution per unit for the fourth quarter of 2010. For additional information regarding our cash distributions, equity and units outstanding, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(5) In general, our consolidated debt has increased over time as a result of financing all or a portion of acquisitions and other capital spending.
(6) In general, the increase in equity over the periods presented primarily reflects proceeds from the issuance of limited partner units by Enterprise in underwritten public offerings and, less frequently, in connection with

acquisitions or other transactions.

(7) Total limited partner units outstanding increased in 2010 as a result of the Holdings Merger and reflects, following the Holdings Merger, the number of Enterprise limited partner units outstanding.

Table of Contents

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

For the years ended December 31, 2010, 2009 and 2008.

The following information should be read in conjunction with our consolidated financial statements and accompanying notes included under Item 8 of this annual report. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Overview of Business.
- Basis of Financial Statement Presentation.
- Significant Recent Developments – Discusses significant developments during the year ended December 31, 2010 and through the date of this filing.
- General Outlook for 2011.
- Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.
- Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.
- Critical Accounting Policies and Estimates.
- Other Items – Includes information related to contractual obligations, off-balance sheet arrangements and other matters.

Our financial statements have been prepared in accordance with U.S. GAAP.

Cautionary Note Regarding Forward-Looking Statements

This discussion 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," "co "will," "believe," "may," "potential" and 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.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. 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. 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 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 conduct substantially all of our business through EPO. We are owned 100% by our limited partners from an economic perspective. Enterprise GP, which is owned 100% by Dan Duncan LLC, owns a non-economic general partner interest in us.

Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) 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.

Significant Recent Developments

The following information highlights significant developments since January 1, 2010 through the date of this filing (March 1, 2011), including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations.

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.

Incident at Mont Belvieu Storage

On February 8, 2011, a fire occurred at our Mont Belvieu, Texas storage complex (at the West Storage facility), which is jointly owned with Duncan Energy Partners. The incident resulted in one fatality. The West Storage facility consists of ten 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.

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 EPGP'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.

New Enterprise NGL Fractionator Begins Commercial Operations

In November 2010, we announced that our fourth NGL fractionator at our Mont Belvieu, Texas complex had commenced operations. The new NGL fractionator provides 75 MBPD of capacity to accommodate growing NGL volumes from producing areas such as the Barnett Shale in North Texas and the Rockies. The new facility is supported by long-term, firm contracts and increases NGL fractionation capacity at our Mont Belvieu complex to 305 MBPD.

Duncan Energy Partners Executes $1.25 Billion in New Credit Facilities

In October 2010, Duncan Energy Partners entered into new long-term variable-rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. The new Duncan Energy Partners credit facilities mature in October 2013 and consist of: (i) an $850.0 million multi-year revolving credit facility (the "DEP Multi-Year Revolving Credit Facility") and (ii) a $400.0 million term loan facility (the "DEP $400 Million Term Loan Facility"). At closing, Duncan Energy Partners borrowed the full amount available under the DEP $400 Million Term Loan Facility to repay amounts outstanding under the DEP Revolving Credit Facility and an intercompany loan with EPO. Upon repayment, the DEP Revolving Credit Facility and the loan agreement with EPO were terminated. Duncan Energy Partners' existing $282.3 million DEP Term Loan remains in place and is scheduled to mature in December 2011.

Duncan Energy Partners entered into the new $1.25 billion credit agreements primarily to fund its 66% share of the Haynesville Extension project costs. Variable interest rates charged under the new credit facilities are based on the London InterBank Offered Rate (or "LIBOR") or a base rate, both as defined in the agreements.

Expansion of Eagle Ford Shale Capabilities with New Construction Projects

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, Petrohawk Energy Corporation and Pioneer Natural Resources USA, Inc. 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 increase capacity at the Wilson gas storage facility by 5 Bcf 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 60 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 crude oil pipeline and associated storage assets that will serve producers in the Eagle Ford Shale basin. This new pipeline will facilitate crude oil deliveries to the Cushing and Houston markets and is expected to be completed in the fourth quarter of 2011.

Operations Commence at New Port Arthur Refined Products Storage Facility

In June 2010, we announced that the partnership's new refined products storage facility in Port Arthur, Texas, which was built to support the expansion of a nearby third-party refinery, had commenced commercial operations and received its first deliveries. The new tank farm serves as the sole distribution point for output from the refinery as part of a 15-year throughput and volume dedication agreement. Our Port Arthur storage facility, which represents an investment of approximately $330.0 million, features 5.4 MMBbls of storage capacity for gasoline, diesel and jet fuel. The storage facility provides our customer with access to several major refined products pipelines, including our Products Pipeline System.

Acquisition of State Line and Fairplay Natural Gas Gathering Systems

In May 2010, we acquired 100% ownership of the State Line and Fairplay natural gas gathering systems and related assets from Momentum for approximately $1.2 billion in cash. These systems are located in northwest Louisiana and East Texas and gather and treat natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations. We used a portion of the net proceeds from our April 2010 equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to fund this acquisition.

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas. The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 MMcf/d and two natural gas treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 397 MMcf/d of natural gas. The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes approximately 249 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 285 MMcf/d. The Fairplay system is currently gathering approximately 156 MMcf/d of natural gas. Our operations related to the Fairplay system include providing natural gas processing services using third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

Our State Line system will connect to our Haynesville Extension natural gas pipeline project. The Haynesville Extension, which is under development by Acadian Gas, is expected to provide shippers with takeaway capacity from the Haynesville Shale producing basin and flexible options for reaching attractive markets for their natural gas, including access to nine interstate gas pipeline systems. The Fairplay system is expected to extend our asset base through planned 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.

Basis of Financial Statement Presentation

In accordance with rules and regulations of the SEC and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of the financial information of businesses that we control such as through the ownership of general partner interests (e.g., Duncan Energy Partners). Our general purpose consolidated financial statements present those investments in which we do not have a controlling interest as unconsolidated affiliates (e.g., our equity method investment in Energy Transfer Equity). As presented in our consolidated financial statements, noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries.

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

The primary differences between Holdings' and Enterprise's consolidated results of operations were (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our noncontrolling interests.

Historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding earnings per unit.

Table of Contents

General Outlook for 2011

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Factors that can affect the demand for our services include global and U.S. economic conditions, the demand for energy, the market price of energy, the cost to develop natural gas and crude oil reserves in the U.S. and the cost and availability of capital to energy companies to invest in drilling activities.

The global economic expansion that began in late 2009 continued throughout 2010, with all of the twenty largest developed economies (the "G20") reporting year-over-year growth in real gross domestic product (or "GDP") for 2010. This growth appears to be continuing in early 2011. The United States reported year-over-year real GDP growth of 2.8% for 2010 compared to 2009. By comparison, the United States reported year-over-year real GDP growth of 0.1% for 2009 compared to 2008.

Similar to the rate of economic growth, U.S. demand for petroleum products and natural gas (as reported by the U.S. Energy Information Administration) increased by approximately 2.0% and 4.5%, respectively, for the first ten months of 2010 versus the same period in 2009. Likewise, U.S. demand for petroleum products for transportation purposes (e.g., motor gasoline, distillate and jet fuel) for the first ten months of 2010 increased by 1.6% compared to the same period of 2009.

Energy prices have generally rebounded with the recovery in demand and economic growth. The average prices of West Texas Intermediate crude oil, Henry Hub natural gas and Mont Belvieu ethane for 2010 were approximately $79.53 per barrel, $4.39 MMBtu, and $0.60 per gallon, respectively, which increased by approximately 29%, 10% and 24%, respectively, from 2009. Notably, the substantial change in the price relationship between natural gas and crude oil that began in 2009 has continued. In 2008, natural gas was priced at 52% of crude oil on an energy equivalent basis compared to 37% in 2009 and 31% in 2010.

Natural gas and NGLs have had a significant price advantage over more costly crude oil and crude oil derivatives (such as naphtha) and this trend is expected to continue based on prices currently quoted on the futures markets. This has been primarily driven by (i) a decline in global crude oil excess production capacity; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China, India and other developing countries; (v) the globalization of international natural gas markets with more foreign-based LNG liquefaction facilities becoming operational; (vi) the technological breakthroughs around the development of natural gas shale resource basins in the United States that have decreased finding and development costs for natural gas and NGLs; and (vii) the general inability to export natural gas from the United States.

We believe this has led to a long-term structural change in feedstock selection by the petrochemical industry. For ethylene producers, which are the largest consumers of NGLs, ethane and propane have been the most consistently profitable feedstocks in 2009 and 2010 and are forecasted to remain so in 2011. Lower feedstock costs have provided U.S. ethylene producers with a competitive cost advantage globally, especially relative to crackers in Europe and Asia, which are limited to naphtha feedstocks.

Per industry publications, domestic production of ethylene increased approximately 6% from 2009 to 2010 and notional domestic demand was up approximately 10%. As a result of increased domestic demand, net exports of ethylene and ethylene derivatives in 2010 decreased to approximately 19% of ethylene production, which compares to 22% of domestic production that was exported in 2009.

U.S. ethylene producers responded by maximizing their use of NGLs as a feedstock, rationalizing some of their facilities and investing capital, beginning in 2009, to modify their furnaces to crack more NGLs. The U.S. ethylene industry consumed an average of approximately 743 MBPD of ethane from 2004 through 2008. In 2010, the average ethane consumption of U.S. ethylene producers increased by 19.8% to approximately 890 MBPD. Based on our internal estimates, during certain days in December 2010, we believe the domestic ethylene industry's demand for ethane exceeded 1 million barrels per day. We estimate the U.S. ethylene industry could consume approximately 100 MBPD of incremental ethane and propane feedstocks over the next two years through modifications to existing facilities. Certain non-U.S. based ethylene crackers have responded to the NGL feedstock cost advantage by importing propane, including propane produced in the U.S., to displace crude oil derivatives to feed their heavy crackers.

Strong end user demand for NGLs and increases in NGL-rich natural gas production from developing shale plays such as the Eagle Ford Shale are expected to (i) keep certain of our natural gas pipelines and processing plants and our NGL fractionators, pipelines, storage and export facilities operating at high utilization rates; (ii) provide attractive natural gas processing margins for our equity NGL production; and (iii) provide us with opportunities to invest capital to build new natural gas pipelines and processing facilities; NGL fractionation and pipeline facilities; and crude oil pipelines.

Henry Hub natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to less than $4.00 per MMBtu in February 2011. This price decrease has generally resulted in energy companies reallocating and, in some cases, reducing their drilling capital expenditure budgets. This led to a substantial decrease in the number of rigs drilling for natural gas in the U.S., declining from a peak of 1,606 rigs in August 2008 to a low of 665 rigs in July 2009 as natural gas prices approached a low of $1.88 per MMBtu in September 2009. The natural gas rig count has since rebounded and averaged 940 rigs in 2010. Even though the total natural gas rig count has dropped from peak levels, the substantial efficiencies of horizontal drilling in the non-conventional and shale supply basins have allowed producers to maintain overall natural gas deliverability. As a result, rig count is not necessarily a reliable indicator of the level of future natural gas production or reserves. Because of the market prices of crude oil and NGLs, drilling activity is especially robust in shale plays with crude oil, condensate and NGL-rich natural gas production such as the Eagle Ford, Granite Wash, Bakken and Marcellus. Drilling activity in shale plays with dry natural gas production, such as the Haynesville/Bossier and Fayetteville, is down slightly from peak levels, but remains very active as certain producers are drilling to hold recently executed leases or have entered into joint ventures whereby their new joint venture partners are providing the capital to fund the development of the area for a certain time and for a certain dollar amount. Generally, rig counts remain significantly below peak levels in areas with conventional natural gas reserves, which may have higher finding costs, and areas where producers already have leases held by production.

Based on forecasted drilling activity, the number of wells waiting to be connected to our pipeline systems and the respective production decline curves, we believe the aggregate natural gas pipeline volumes transported on our Jonah Gas Gathering, Piceance Basin Gathering and San Juan Gathering systems for 2010 could range from an increase of 5% to a decrease of 5% compared to volumes transported in 2010. These areas have substantial, undeveloped non-conventional natural gas reserves with some of the lowest finding costs in the U.S.; prospects to develop additional shale horizons; and are supported by existing pipeline infrastructure to transport the natural gas to market. We believe that as U.S. natural gas supply and demand becomes more balanced and natural gas prices become less volatile, these areas could experience an increase in drilling activity to support, and potentially increase, current production levels.

In the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System, we have completed several pipeline projects that enable us to gather, transport and process up to 300 MMcf/d of new natural gas production from the area. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated they plan to accelerate their associated drilling programs. Production from this region includes crude oil, condensate, NGL-rich natural gas and lean natural gas. In 2010, we announced expansions of our natural gas pipeline, storage and processing facilities; NGL pipeline and fractionation facilities; and crude oil pipeline and storage facilities to facilitate production growth from this region. These projects represent approximately $2.7

billion of capital expenditures in the aggregate from 2010 through 2012.

Natural gas production growth from the Haynesville/Bossier shale area of northern Louisiana is expected to grow rapidly over the next several years. In late 2009, we announced that seven energy companies had executed long-term agreements to support the Haynesville Extension project of our Acadian

Table of Contents

Gas System. The Haynesville Extension is a 270-mile, 42-inch/36-inch pipeline designed to transport 1.8 Bcf/d of natural gas. Construction of the pipeline began in January 2011 and is scheduled to begin commercial operations in September 2011. Total capital cost for the Haynesville Extension is approximately $1.56 billion.

We estimate that natural gas and crude oil volumes handled by our offshore Gulf of Mexico assets will be lower in 2011 than 2010 due to lower drilling and development activities in the second half of 2010 and the beginning of 2011 caused by federal regulatory uncertainty in the aftermath of BP's Macando oil spill. We believe volumes on our systems will increase from 2010 levels once drilling and development activities resume. We estimate average volumes on our largest offshore asset, the Independence Hub platform and Trail pipeline will range between 450 BBtus/d and 500 BBtus/d in 2011 compared to an average of 576 BBtus/d in 2010.

Our refined products pipeline systems generally serve the Petroleum Administration for Defense District ("PADD") 2 of the U.S. Demand for refined products in this region for 2010 was approximately 4.5 MMBbls/d, which was a 2.2% change compared to 2009. Throughput volumes in 2010 on our refined products pipeline systems increased to 734 MBPD, or an 8% increase compared to 2009. We do not expect a significant increase in refined product demand in 2011 in this region due to soft economic conditions and ongoing conservation.

Liquidity Outlook

The corporate debt and equity capital markets continued to improve in 2010. Sovereign credit markets, however, continue to be volatile due to large budget deficits being incurred by the United States, United Kingdom and many developed European countries. The cost of our term debt and equity capital generally declined to pre-financial crisis levels. The availability of term debt and equity capital also improved. Likewise, the general availability of credit commitments from most banks also improved from a year ago; however, the cost of new bank debt is higher than pre-crisis levels (by approximately 1.5% on borrowed money).

In January 2011, we completed a public offering of $750 million of 5-year senior notes and $750 million of 30-year senior notes. On February 1, 2011, we retired $450 million of maturing senior notes. After adjusting our liquidity at December 31, 2010 for these events, we had consolidated liquidity of approximately $2.9 billion. We currently estimate that our capital expenditures for 2011 will approximate $3.7 billion, which includes approximately $3.4 billion for growth capital projects and $260 million for sustaining capital expenditures. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs. Also, based on information currently available to us, we believe we will maintain our investment grade credit ratings and meet our loan covenant obligations in 2011.

We have approximately $3.35 billion of senior notes maturing in the period beginning 2012 through the end of 2014. In addition, we have bank term loans and bank credit facilities with commitments totaling approximately $3.3 billion maturing in the period beginning December 2011 through the end of 2013. The U.S. government is expected to run substantial annual budget deficits, exceeding a trillion dollars, that will require a corresponding issuance of debt by the U.S. Treasury from 2011 through 2014. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what the impact of the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital. To date, we have executed approximately $1.65 billion of interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of our debt that matures during the 2012 through 2013 time period. We will continue to monitor and evaluate the condition of the capital markets and interest rate risk with respect to refinancing these maturities and funding our capital expenditures.

Table of Contents

Results of Operations

Selected Price and Volumetric Data

The following table presents selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	Crude Oil, $/barrel (4)
2008 Averages	$ 9.04	$ 0.89	$ 1.41	$ 1.68	$ 1.72	$ 2.09	$ 0.62	$ 0.52	$ 99.73
2009									
1st Quarter	$ 4.91	$ 0.36	$ 0.68	$ 0.87	$ 0.97	$ 0.96	$ 0.26	$ 0.20	$ 43.31
2nd Quarter	$ 3.51	$ 0.43	$ 0.73	$ 0.93	$ 1.11	$ 1.21	$ 0.34	$ 0.28	$ 59.79
3rd Quarter	$ 3.39	$ 0.47	$ 0.87	$ 1.12	$ 1.19	$ 1.42	$ 0.48	$ 0.43	$ 68.24
4th Quarter	$ 4.16	$ 0.67	$ 1.09	$ 1.39	$ 1.49	$ 1.64	$ 0.50	$ 0.44	$ 76.19
2009 Averages	$ 3.99	$ 0.48	$ 0.84	$ 1.08	$ 1.19	$ 1.31	$ 0.39	$ 0.34	$ 61.88
2010									
1st Quarter	$ 5.30	$ 0.73	$ 1.24	$ 1.52	$ 1.64	$ 1.82	$ 0.63	$ 0.54	$ 78.72
2nd Quarter	$ 4.09	$ 0.55	$ 1.08	$ 1.47	$ 1.58	$ 1.81	$ 0.65	$ 0.44	$ 78.03
3rd Quarter	$ 4.38	$ 0.48	$ 1.07	$ 1.38	$ 1.43	$ 1.71	$ 0.58	$ 0.44	$ 76.20
4th Quarter	$ 3.80	$ 0.64	$ 1.26	$ 1.62	$ 1.68	$ 2.00	$ 0.59	$ 0.49	$ 85.17
2010 Averages	$ 4.39	$ 0.60	$ 1.16	$ 1.50	$ 1.58	$ 1.84	$ 0.61	$ 0.48	$ 79.53

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. (“CMAI”). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the NYMEX.

Table of Contents

The following table presents our significant average throughput, production and processing volumetric data for the periods presented. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for recently purchased assets from the date of acquisition.

	For Year Ended December 31,		
	2010	2009	2008
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	2,322	2,196	2,021
NGL fractionation volumes (MBPD)	485	461	441
Equity NGL production (MBPD)	121	117	108
Fee-based natural gas processing (MMcf/d)	2,932	2,650	2,524
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	11,482	10,435	9,612
Onshore Crude Oil Pipelines & Services, net:			
Crude oil transportation volumes (MBPD)	670	680	696
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,242	1,420	1,408
Crude oil transportation volumes (MBPD)	320	308	169
Platform natural gas processing (MMcf/d)	513	700	632
Platform crude oil processing (MBPD)	17	12	15
Petrochemical & Refined Products Services, net:			
Butane isomerization volumes (MBPD)	89	97	86
Propylene fractionation volumes (MBPD)	77	68	58
Octane enhancement production volumes (MBPD)	16	10	9
Transportation volumes, primarily refined products and petrochemicals (MBPD)	869	806	818
Total, net:			
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	4,181	3,990	3,704
Natural gas transportation volumes (BBtus/d)	12,724	11,855	11,020
Equivalent transportation volumes (MBPD) (1)	7,529	7,110	6,604

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2010	2009	2008
Revenues	$33,739.3	$25,510.9	$35,469.6
Operating costs and expenses	31,449.3	23,565.8	33,618.9
General and administrative costs	204.8	182.8	144.8
Equity in income of unconsolidated affiliates	62.0	92.3	66.2
Operating income	2,147.2	1,854.6	1,772.1
Interest expense	741.9	687.3	608.3
Provision for income taxes	26.1	25.3	31.0

Net income	1,383.7	1,140.3	1,145.1
Net income attributable to noncontrolling interest	1,062.9	936.2	981.1
Net income attributable to partners	320.8	204.1	164.0

For information regarding amounts attributable to noncontrolling interest, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Our gross operating margin by business segment and in total is as follows for the periods presented (dollars in millions):

	For Year Ended December 31, 2010	2009	2008
NGL Pipelines & Services	$1,732.6	$1,628.7	$1,325.0
Onshore Natural Gas Pipelines & Services	527.2	501.5	589.9
Onshore Crude Oil Pipelines & Services	113.7	164.4	132.2
Offshore Pipeline & Services	297.8	180.5	187.0
Petrochemical & Refined Products Services	584.5	364.7	374.9
Other Investments	(2.8)	41.1	31.3
Total segment gross operating margin	$3,253.0	$2,880.9	$2,640.3

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see "Other Items – Non-GAAP Reconciliations" included within this Item 7. For additional information regarding our business segments, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following table summarizes each business segment's contribution to revenues (net of eliminations and adjustments) for the periods presented (dollars in millions):

	For Year Ended December 31, 2010	2009	2008
NGL Pipelines & Services:			
Sales of NGLs	$13,447.1	$11,598.9	$14,573.5
Sales of other petroleum and related products	2.3	1.8	2.4
Midstream services	753.1	708.3	737.9
Total	14,202.5	12,309.0	15,313.8
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,928.7	2,410.5	3,083.1
Midstream services	772.9	739.4	733.3
Total	3,701.6	3,149.9	3,816.4
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	10,710.4	7,110.6	12,696.2
Midstream services	84.4	80.4	67.6
Total	10,794.8	7,191.0	12,763.8
Offshore Pipelines & Services:			
Sales of natural gas	1.3	1.2	2.8
Sales of crude oil	9.5	5.3	11.1
Midstream services	299.9	333.4	254.5
Total	310.7	339.9	268.4
Petrochemical & Refined Products Services:			
Sales of other petroleum and related products	4,009.1	1,991.8	2,757.6
Midstream services	720.6	529.3	549.6
Total	4,729.7	2,521.1	3,307.2
Total consolidated revenues	$33,739.3	$25,510.9	$35,469.6

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, 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, which accounted for 11.2% of our consolidated revenues.

Comparison of Year Ended December 31, 2010 with Year Ended December 31, 2009

Revenues for 2010 were $33.74 billion compared to $25.51 billion for 2009, an $8.23 billion year-to-year increase. Higher energy commodity sales prices and volumes during 2010 compared to 2009 resulted in a $7.99 billion year-to-year increase in consolidated revenues from the sale of NGLs, natural gas, crude oil and petrochemical and refined products. Consolidated revenues from sales of NGLs increased $1.85 billion year-to-year primarily due to higher sales prices during 2010 compared to 2009. Revenues from sales of natural gas increased $518.3 million year-to-year due to higher sales prices and volumes. Crude oil sales revenues increased $3.6 billion year-to-year primarily due to higher sales prices. Consolidated revenues from sales of other petroleum and related products increased $2.02 billion year-to-year primarily due to (i) higher petrochemical and refined products sales volumes and (ii) higher propylene sales prices during 2010 compared to 2009. Collectively, the remainder of our consolidated revenues increased $240.1 million year-to-year primarily due to revenues generated from businesses we acquired or assets we constructed, principally the State Line and Fairplay natural gas gathering systems we acquired in May 2010 and a trucking business we acquired from EPCO in September 2010.

Operating costs and expenses were $31.45 billion for 2010 compared to $23.57 billion for 2009, a $7.88 billion year-to-year increase. The cost of sales related to our marketing activities increased $7.23 billion year-to-year primarily due to higher energy commodity prices and sales volumes. The operating costs and expenses of our natural gas processing plants increased $493.6 million year-to-year primarily due to higher plant thermal reduction ("PTR") costs attributable to an increase in natural gas prices and processing volumes. Operating costs and expenses for 2010 include approximately $174.3 million attributable to business acquisitions and the placing in service of newly constructed assets during the year. Operating costs and expenses for 2009 include aggregate charges of $135.3 million related to our dissociation from the Texas Offshore Port System partnership ("TOPS") and $28.7 million of expenses incurred by TEPPCO in connection with its river terminal business.

Depreciation, amortization and accretion expenses included in operating costs and expenses increased $127.0 million year-to-year primarily due to an increase in depreciation and amortization expense attributable to assets acquired in connection with business acquisitions in 2010 and the placing in service of newly constructed assets during 2010. We recorded $8.4 million of non-cash asset impairment charges during 2010 compared to $33.5 million of charges during 2009, a $25.1 million year-to-year decrease. Non-cash impairment charges recorded in 2009 include $22.8 million of expense incurred by TEPPCO related to its refined products terminals. Gains from asset sales and related transactions included in operating costs and expenses increased $44.4 million year-to-year, which is primarily due to $56.6 million of insurance-related gains recorded in connection with our disposition of certain offshore assets in 2010.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.16 per gallon during 2010 versus $0.85 per gallon during 2009 – a 36% year-to-year increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.39 per MMBtu during 2010 versus $3.99 per MMBtu during 2009. The market price of crude oil (as measured on the NYMEX) averaged $79.53 per barrel during 2010 compared to $61.88 per barrel during 2009 – a 29% year-to-year increase. See "Selected Price and Volumetric Data" included within this Item 7 for additional historical energy commodity pricing information.

General and administrative costs were $204.8 million for 2010 compared to $182.8 million for 2009, a $22.0 million year-to-year increase. General and administrative costs for 2010 include $20.2 million of expense related to the Employee Partnership liquidations and $24.5 million of expenses related to the Holdings Merger. General and administrative costs for 2009 include $31.0 million of expenses related to the TEPPCO Merger. Collectively, the remainder of our general and administrative costs increased $8.3 million year-to-year primarily due to higher expenses for director compensation and legal and tax professional services.

Equity in income of our unconsolidated affiliates was $62.0 million for 2010 compared to $92.3 million for 2009. The $30.3 million year-to-year decrease is primarily due to a $43.9 million decrease in equity earnings from Energy Transfer Equity, partially offset by improved results from our investments in midstream energy companies operating in Gulf of Mexico and higher earnings from Promix and Centennial.

Table of Contents

Operating income for 2010 was $2.15 billion compared to $1.85 billion for 2009. Collectively, the changes in revenues, costs and expenses and equity in income of unconsolidated affiliates described above resulted in the $292.6 million year-to-year increase in operating income.

Interest expense increased to $741.9 million for 2010 from $687.3 million for 2009, a $54.6 million year-to-year increase. Interest expense for 2010 includes $31.0 million of charges related to Holdings' interest rate swaps and the write-off of Holdings' unamortized debt issuance costs. The remainder of the increase in interest expense is primarily due to EPO's issuance of Senior Notes Q and R during October 2009 and Senior Notes X, Y and Z in May 2010. Average debt principal outstanding increased to $13.23 billion during 2010 from $13.0 billion during 2009.

Provision for income taxes increased $0.8 million year-to-year. Higher expenses associated with the Texas Margin Tax were partially offset by a $6.6 million one-time charge associated with taxable gains arising from the sale of certain assets by Dixie Pipeline Company ("Dixie") during 2009.

As a result of items noted in the previous paragraphs, our consolidated net income increased $243.4 million year-to-year to $1.38 billion for 2010 compared to $1.14 billion for 2009. Net income attributable to noncontrolling interests was $1.06 billion for 2010 compared to $936.2 million for 2009. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our net income attributable to noncontrolling interests. Net income attributable to partners increased $116.7 million year-to-year to $320.8 million for 2010 compared to $204.1 million for 2009.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.73 billion for 2010 compared to $1.63 billion for 2009, a $103.9 million year-to-year increase. Gross operating margin for 2009 includes $5.9 million of gains related to insurance proceeds. The following paragraphs provide a discussion of segment results excluding gains from insurance proceeds.

Gross operating margin from our natural gas processing and related NGL marketing business was $989.9 million for 2010 compared to $947.9 million for 2009, a $42.0 million year-to-year increase. Equity NGL production increased to 121 MBPD during 2010 from 117 MBPD during 2009. Our Rocky Mountains natural gas processing plants contributed $31.6 million of the year-to-year increase in gross operating margin primarily due to increased equity NGL production. Gross operating margin from our natural gas processing activities in Texas increased $16.4 million year-to-year due to higher volumes and processing margins, including $9.8 million of gross operating margin attributable to natural gas processing activities on the Fairplay system, which we acquired in May 2010. Gross operating margin from our NGL marketing activities increased $4.5 million year-to-year due to higher sales volumes and margins. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased $10.5 million year-to-year primarily due to lower natural gas processing margins and fee-based processing volumes in at our plants in southern Louisiana and the San Juan and Permian Basins.

Gross operating margin from our NGL pipelines and related storage business was $604.8 million for 2010 compared to $538.9 million for 2009, a $65.9 million year-to-year increase. Total NGL transportation volumes increased to 2,322 MBPD during 2010 from 2,196 MBPD during 2009. Collectively, gross operating margin from our Louisiana NGL pipelines and Dixie Pipeline increased $55.7 million year-to-year primarily due to a 50 MBPD increase in throughput volumes and an increase in certain fees. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline increased $17.6 million year-to-year primarily due to a 46 MBPD year-to-year increase in volumes. Gross operating margin from our storage and related terminal businesses increased $29.1 million year-to-year primarily due to higher storage volumes and fees, with our Mont Belvieu storage facility contributing $12.7 million of this increase. In addition, gross operating margin from our Rio Grande pipeline, which we acquired in the fourth quarter of 2009, increased $5.3 million year-to-year. Improved results from these

Table of Contents

assets were partially offset by a combined $39.2 million decrease in gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals attributable to a $29.2 million benefit recorded for the Mid-America Pipeline System in 2009 related to a rate case settlement, a combined 16 MBPD decrease in throughput volumes on these systems and higher operating expenses. Gross operating margin from our remaining NGL pipelines decreased $2.6 million year-to-year primarily due to a $6.8 million charge we recorded during the third quarter of 2010 for a dispute involving a pipeline in South Texas.

Gross operating margin from our NGL fractionation business was $137.9 million for 2010 compared to $136.0 million for 2009, a $1.9 million increase year-to-year. Our NGL fractionation volumes were 485 MBPD during 2010 compared to 461 MBPD during 2009. Gross operating margin from our Mont Belvieu and Promix NGL fractionation facilities increased $15.1 million year-to-year primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we added 75 MBPD of NGL fractionation capacity by completing and placing into service a fourth NGL fractionator at our complex in Mont Belvieu, Texas. Gross operating margin from the remainder of our NGL fractionators decreased $13.2 million year-to-year, primarily due to a $12.6 million year-to-year decrease in gross operating margin from our Norco fractionator related to hedging and operating gains recorded during 2009 that did not repeat in 2010.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $527.2 million for 2010 compared to $501.5 million for 2009, a $25.7 million year-to-year increase. Our onshore natural gas transportation volumes were 11.48 TBtus/d during 2010 compared to 10.44 TBtus/d during 2009.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $471.7 million for 2010 compared to $448.5 million for 2009, a $23.2 million year-to-year increase. Gross operating margin for 2010 includes $33.0 million from the State Line and Fairplay natural gas gathering systems, which we acquired in May 2010. Gross operating margin from our Texas Intrastate System increased $22.0 million year-to-year primarily due to higher firm capacity reservation fees on the Sherman Extension pipeline. Gross operating margin from our San Juan Gathering System increased $26.2 million year-to-year primarily due to higher average gathering fees and lower operating expenses during 2010 compared to 2009. Our Central Treating Facility in the Rocky Mountains, which commenced operations in March 2009, contributed $11.5 million of the year-to-year increase in segment gross operating margin. Collectively, gross operating margin from our Jonah, Val Verde and Carlsbad gathering systems decreased $21.2 million year-to-year primarily due to lower natural gas gathering volumes. Collectively, gross operating margin from the remainder of our onshore natural gas pipelines and related marketing activities decreased $48.3 million year-to-year primarily due to lower sales margins and higher transportation and storage expenses associated with our natural gas marketing activities.

Natural gas basis differentials in Texas (specifically, the difference in natural gas prices between markets in West Texas and East Texas) were significantly lower during 2010 relative to 2009. The year-to-year decrease in basis differentials resulted in lower sales margins associated with our natural gas marketing activities during 2010 and a decrease in interruptible transportation volumes on our Texas Intrastate System.

Gross operating margin from our natural gas storage business was $55.5 million for 2010 compared to $53.0 million for 2009. The $2.5 million year-to-year increase in gross operating margin is primarily due to higher revenues and lower operating expenses at our Petal natural gas storage facility during 2010 compared to 2009.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $113.7 million for 2010 compared to $164.4 million for 2009, a $50.7 million decrease year-to-year. Total onshore crude oil transportation volumes decreased to 670 MBPD during 2010 compared to 680 MBPD during 2009. Gross operating margin from our crude oil marketing and related activities decreased $53.9 million year-to-year primarily due to lower sales margins resulting from a competitive crude oil marketing environment (i.e., lower basis differentials year-to-year) and higher pipeline and truck transportation costs.

Basis differentials represent the difference in crude oil prices between two locations or price differences for various qualities of crude oil (e.g., “sweet” crude versus “sour” crude). Gross operating margin from our crude oil terminal operations in Midland, Texas and Cushing, Oklahoma decreased $3.6 million year-to-year primarily due to higher operating expenses. Collectively, gross operations from the remainder of our onshore crude oil businesses increased $6.8 million year-to-year primarily due to higher throughput volumes on our West Texas pipeline system and higher volumes and fees on our Red River pipeline system.

Offshore Pipelines & Services. Gross operating margin from this business segment was $297.8 million for 2010 compared to $180.5 million for 2009, a $117.3 million increase year-to-year. Results for 2010 include $27.5 million of gains related to insurance proceeds compared to $39.7 million of such gains in 2009. Results for 2009 include $135.3 million of charges related to our dissociation from TOPS. Gross operating margin from this business segment decreased $5.8 million year-to-year excluding the effects of insurance proceeds and charges related to TOPS.

In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. (“Oiltanking”) formed TOPS. In April 2009, we and TEPPCO dissociated from TOPS and recorded a $68.4 million charge to write-off our investment in the joint venture. In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

The following paragraphs provide a discussion of segment results excluding insurance-related gains and the charges associated with TOPS.

In general, natural gas and crude oil drilling activity in the Gulf of Mexico ceased as a result of the federal offshore drilling moratorium, which went into effect in May 2010. This resulted in lower throughput volumes available to certain of our offshore pipeline and platform assets. The moratorium was lifted in October 2010; however, we are uncertain as to when oil and gas drilling activity in the Gulf of Mexico will return to pre-moratorium levels. For additional information regarding the federal offshore drilling moratorium, see page 63 of Part I, Item 1A “Risk Factors.”

Gross operating margin from our offshore crude oil pipeline business was $97.9 million for 2010 compared to $79.3 million for 2009, an $18.6 million year-to-year increase. Equity earnings from Poseidon increased $5.7 million year-to-year primarily due to higher transportation volumes and lower operating expenses. In addition, gross operating margin from our Shenzi crude oil pipeline, which commenced operations in April 2009, increased $4.0 million year-to-year. Collectively, gross operating margin from the remainder of our crude oil pipelines increased $8.9 million year-to-year primarily due to increased transportation volumes. Certain of these pipelines were either in limited service or out-of-service completely during 2009 due to the lingering effects of Hurricanes Gustav and Ike on energy infrastructure in the Gulf of Mexico. Despite the effects of the federal offshore drilling moratorium, total offshore crude oil transportation volumes averaged 320 MBPD during 2010 compared to 308 MBPD during 2009.

Gross operating margin from our offshore natural gas pipeline business was $45.5 million for 2010 compared to $54.2 million for 2009, an $8.7 million year-to-year decrease. Total offshore natural gas transportation volumes were 1,242 BBtus/d during 2010 versus 1,420 BBtus/d during 2009. Gross operating margin from our Independence Trail pipeline decreased $31.2 million year-to-year primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 576 BBtus/d during 2010 from 805 BBtus/d during 2009 as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium. Collectively, gross operating margin from the remainder of our offshore natural gas pipelines increased $22.5 million year-to-year primarily due to a year-to-year decrease in operating expenses as a result of property damage repair expenses we recorded during 2009 and revenue increases on our HIOS pipeline system in 2010.

Table of Contents

Gross operating margin from our offshore platform services business was $126.9 million for 2010 compared to $142.6 million for 2009, a $15.7 million decrease year-to-year. Our net platform natural gas processing volumes were 513 MMcf/d during 2010 compared to 700 MMcf/d during 2009. The year-to-year decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $584.5 million for 2010 compared to $364.7 million for 2009, a $219.8 million increase year-to-year.

Gross operating margin from propylene fractionation and related activities was $212.4 million for 2010 compared to $89.6 million for 2009. The $122.8 million year-to-year increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins. Propylene sales margins increased year-to-year as a result of improved consumer demand for propylene derivative products and lower propylene production from ethylene crackers (which impacted supply) during 2010 compared to 2009. Propylene fractionation volumes increased to 77 MBPD during 2010 from 68 MBPD during 2009.

Gross operating margin from octane enhancement was $47.0 million for 2010 compared to $11.5 million for 2009. The $35.5 million year-to-year increase in gross operating margin is primarily due to higher sales volumes and margins from motor gasoline additives and revenues from by-product sales. Octane enhancement production volumes were 16 MBPD during 2010 compared to 10 MBPD during 2009.

Gross operating margin from butane isomerization was $84.9 million for 2010 compared to $76.2 million for 2009. The $8.7 million year-to-year increase in gross operating margin is primarily due to higher commodity prices, which resulted in increased revenues from by-product sales and more than offset the effect of lower isomerization volumes. Butane isomerization volumes decreased to 89 MBPD during 2010 from 97 MBPD during 2009.

Gross operating margin from refined products pipelines and related activities was $170.8 million for 2010 compared to $124.7 million for 2009, a $46.1 million year-to-year increase. Gross operating margin for 2009 includes a $28.7 million charge recognized by TEPPCO in the third quarter of 2009 in connection with its river terminal business. Collectively, gross operating margin from the remainder of our refined products pipelines and related activities increased $17.4 million year-to-year primarily due to the expansion of our refined products marketing activities and the completion of our 5.3 million barrel refined products terminal in Port Arthur, Texas, which generated $7.4 million of gross operating margin for 2010. Pipeline transportation volumes for the refined products business were 734 MBPD during 2010 compared to 682 MBPD during 2009.

Gross operating margin from marine transportation and other segment services was $69.4 million for 2010 compared to $62.7 million for 2009, a $6.7 million year-to-year increase. An increase in gross operating margin attributable to earnings from recently acquired and constructed marine vessels was partially offset by higher operating expenses during 2010 as compared to 2009.

Other Investments. Gross operating margin from this business segment was a loss of $2.8 million for 2010 compared to income of $41.1 million for 2009, a $43.9 million year-to-year decrease. This segment reflects our noncontrolling ownership interests in Energy Transfer Equity and its general partner, LE GP, which are accounted for using the equity method. In December 2010, we sold our entire membership interest in LE GP and recorded a nominal gain on the transaction.

According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of $1.04 billion for 2010 compared to $1.11 billion for 2009, a $73.7 million year-to-year decrease. Operating income from

Energy Transfer Equity's investment in ETP decreased $69.4 million year-to-year primarily due to higher maintenance and ad valorem tax expenses and an increase in depreciation and amortization expenses related to acquired or constructed assets. Energy Transfer Equity's operating income for 2010 includes $14.6 million from its investment in RGNC. Collectively, the remainder of Energy Transfer Equity's operating income decreased $18.9 million year-to-year primarily due to $12.8

million of expenses it incurred during 2010 in connection with its acquisition of interests in RGNC and related transactions.

Collectively, all other items included in Energy Transfer Equity's net income decreased $287.6 million year-to-year. Energy Transfer Equity's interest expense increased $156.5 million year-to-year, which includes $66.4 million of losses during 2010 related to the termination of interest rate swaps. Energy Transfer Equity's net income for 2010 also includes losses of $52.4 million associated with the change in fair value of non-hedged interest rate derivatives compared to gains of $33.6 million for 2009. In addition, Energy Transfer Equity's net income for 2010 includes a $52.6 million non-cash impairment charge recorded by ETP to write down its investment in Midcontinent Express Pipeline LLC to fair value. Collectively, all other items included in Energy Transfer Equity's net income increased $7.5 million year-to-year.

After taking into account noncontrolling interests, income attributable to the partners of Energy Transfer Equity decreased to $192.8 million for 2010 from $442.5 million for 2009. Before the amortization of our excess cost amounts related to this investment, our equity income from Energy Transfer Equity and its general partner was a collective $33.5 million for 2010 versus $77.7 million for 2009. Our equity income from these investments was reduced by $36.3 million and $36.6 million of excess cost amortization during 2010 and 2009, respectively. For additional information regarding our investment in Energy Transfer Equity, see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Comparison of Year Ended December 31, 2009 with Year Ended December 31, 2008

Revenues for 2009 were $25.51 billion compared to $35.47 billion for 2008. The $9.96 billion year-to-year decrease in consolidated revenues is primarily due to lower energy commodity sales prices during 2009 relative to 2008. This factor accounted for a $10.01 billion year-to-year decrease in consolidated revenues associated with our marketing activities. Collectively, the remainder of our consolidated revenues increased $47.9 million year-to-year primarily due to improved results from our offshore activities.

Operating costs and expenses were $23.57 billion for 2009 compared to $33.62 billion for 2008, a $10.05 billion year-to-year decrease. The cost of sales of our marketing activities decreased $9.59 billion year-to-year primarily due to lower energy commodity sales prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $700.0 million year-to-year primarily due to lower PTR costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for 2009 include aggregate charges of $135.3 million related to our dissociation from TOPS and $28.7 million of expenses incurred by TEPPCO in connection with its river terminal business. We recorded $33.5 million of non-cash asset impairment charges during 2009, which includes $22.8 million incurred by TEPPCO related to its refined products terminals. Consolidated operating costs and expenses for 2008 include $49.1 million of repair expenses for property damage sustained by our assets as a result of Hurricanes Gustav and Ike. Collectively, the remainder of our consolidated operating costs and expenses increased $92.0 million year-to-year primarily due to higher depreciation expense recorded during 2009.

Changes in our revenues and operating costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.85 per gallon during 2009 versus $1.40 per gallon during 2008 – a 39% decrease year-to-year. The Henry Hub market price of natural gas averaged $3.99 per MMBtu during 2009 versus $9.04 per MMBtu during 2008 – a 56% decrease year-to-year. The NYMEX crude oil market price averaged $61.88 per barrel during 2009 compared to $99.73 per barrel during 2008 – a 38% decrease year-to-year.

General and administrative costs increased $38.0 million year-to-year primarily due to $31.0 million of expenses we incurred during 2009 in connection with the TEPPCO Merger.

Equity in income of our unconsolidated affiliates was $92.3 million for 2009 compared to $66.2 million for 2008, a $26.1 million year-to-year increase. Collectively, equity in income from our

Table of Contents

investments in Cameron Highway and Poseidon increased $13.8 million year-to-year due to higher crude oil transportation volumes. Equity in income from our investments in White River Hub, LLC ("White River Hub") and Skelly-Belvieu increased $3.1 million and $1.9 million year-to-year, respectively. The assets owned by White River Hub began commercial operations in December 2008. We acquired a 49% equity interest in Skelly-Belvieu during December 2008. Equity in income from our Marco Polo platform decreased $13.3 million year-to-year primarily due to the expiration of demand fee revenues during March 2009. The Marco Polo platform is owned through our investment in Deepwater Gateway. Equity in income from our investments in Energy Transfer Equity and LE GP increased $9.8 million year-to-year. Collectively, equity in income of our other investments increased $10.8 million year-to-year largely due to improved results from our investments in midstream energy companies operating in southern Louisiana.

Operating income for 2009 was $1.85 billion compared to $1.77 billion for 2008. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $82.5 million year-to-year increase in operating income.

Interest expense increased to $687.3 million for 2009 from $608.3 million for 2008. The $79.0 million year-to-year increase in interest expense is primarily due to EPO's issuance of Senior Notes M, N and O during 2008 and a $37.6 million decrease in capitalized interest during 2009 relative to 2008. Average debt principal outstanding increased to $13.0 billion during 2009 from $11.27 billion during 2008 primarily due to debt incurred to fund growth capital investments.

Provision for income taxes decreased $5.7 million year-to-year primarily due to lower expenses associated with the Texas Margin Tax, partially offset by a one-time charge of $6.6 million associated with taxable gains arising from Dixie's sale of certain assets during 2009.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $4.8 million year-to-year to $1.14 billion for 2009 compared to $1.15 billion for 2008. Net income attributable to noncontrolling interests was $936.2 million for 2009 compared to $981.1 million for 2008. Net income attributable to partners increased $40.1 million year-to-year to $204.1 million for 2009 compared to $164.0 million for 2008.

In general, Hurricanes Gustav and Ike had an adverse effect on our operations in the Gulf of Mexico and along the U.S. Gulf Coast during 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues caused by facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for 2008 includes $49.1 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin from our consolidated operations was reduced by approximately $81.0 million during 2008 (i.e., lost business opportunities) as a result of supply interruptions and facility downtime caused by the effects of Hurricanes Gustav and Ike. For more information regarding our insurance program and claims related to these storms, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.63 billion for 2009 compared to $1.33 billion for 2008, a $303.7 million year-to-year increase. Results for 2009 include $5.9 million of gains related to insurance proceeds compared to $1.1 million of such proceeds in 2008. The following paragraphs provide a discussion of segment results excluding the gains from insurance proceeds.

Gross operating margin from our natural gas processing and related NGL marketing business was $947.9 million for 2009 compared to $815.3 million for 2008, a $132.6 million year-to-year increase. Equity NGL production increased to 117 MBPD during 2009 from 108 MBPD during 2008. The Meeker and Pioneer facilities and related hedging program contributed $104.7 million of the year-to-year increase in gross operating margin due to higher volumes and improved processing margins. These Rocky Mountain natural gas processing plants produced 60 MBPD of equity NGLs during 2009 compared to 49 MBPD during 2008. During 2009, we significantly increased the volume of forward sales transactions in connection with our NGL marketing activities, which resulted in higher sales margins and increased utilization of certain of our pipeline and storage facilities. Our NGL marketing activities contributed $95.7 million of the year-to-year increase in gross operating margin. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased $67.8 million year-to-year primarily due to lower NGL sales margins and equity NGL production volumes in Texas and New Mexico.

Gross operating margin from our NGL pipelines and related storage business was $538.9 million for 2009 compared to $397.4 million for 2008, a $141.5 million year-to-year increase. Total NGL transportation volumes increased to 2,196 MBPD during 2009 from 2,021 MBPD during 2008. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $85.7 million year-to-year, which reflected a $29.2 million benefit in 2009 related to a rate case settlement for the Mid-America Pipeline System, an increase in the system-wide tariff, higher volumes and lower fuel costs. Gross operating margin from our NGL import/export terminal and related pipeline increased $20.3 million year-to-year primarily due to higher export volumes. Our Mont Belvieu storage complex contributed $14.9 million of the year-to-year increase in gross operating margin due to higher volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines and related storage assets increased $20.6 million year-to-year primarily due to improved results from our south Louisiana assets.

Gross operating margin from our NGL fractionation business was $136.0 million for 2009 compared to $111.2 million for 2008. Gross operating margin from this business increased $24.8 million year-to-year primarily due to lower fuel costs and higher NGL fractionation volumes at our Mont Belvieu and south Louisiana fractionators during 2009 compared to 2008. Fractionation volumes were 461 MBPD during 2009 compared to 441 MBPD during 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $501.5 million for 2009 compared to $589.9 million for 2008, an $88.4 million year-to-year decrease. Our onshore natural gas transportation volumes were 10.44 TBtus/d during 2009 compared to 9.61 TBtus/d during 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $448.5 million for 2009 compared to $550.5 million for 2008, a $102.0 million year-to-year decrease. Gross operating margin from our San Juan Gathering System decreased $106.4 million year-to-year primarily due to lower fees, which are indexed to regional natural gas prices, and reduced condensate sales revenues as a result of the year-to-year decrease in commodity prices. Gross operating margin from our Texas Intrastate System decreased $14.4 million year-to-year. Earnings from the Sherman Extension pipeline of our Texas Intrastate System during 2009 were more than offset by a year-to-year increase in operating costs and expenses and lower revenues from the sale of condensate. Our Jonah Gathering System contributed a $17.0 million year-to-year increase in gross operating margin primarily due to higher natural gas gathering volumes. Collectively, gross operating margin from the remainder of our onshore natural gas pipelines and related marketing activities increased $1.8 million year-to-year primarily due to improved results from natural gas marketing activities during 2009 compared to 2008.

Gross operating margin from our natural gas storage business was $53.0 million for 2009 compared to $39.4 million for 2008. The $13.6 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed an additional natural gas storage cavern in operation during the third quarter of 2008 at our Petal facility, which provided an incremental 4.2 Bcf of subscribed capacity.

102

Table of Contents

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $164.4 million for 2009 compared to $132.2 million for 2008, a $32.2 million year-to-year increase. Total onshore crude oil transportation volumes were 680 MBPD during 2009 compared to 696 MBPD during 2008. Gross operating margin from crude oil marketing activities increased $36.4 million year-to-year primarily due to higher sales volumes and margins during 2009 relative to 2008. Collectively, gross operating margin from our crude oil terminals in Cushing, Oklahoma and Midland, Texas increased $3.8 million year-to-year primarily due to higher storage revenues and throughput volumes. Gross operating margin from the remainder of our onshore crude oil pipelines decreased $8.0 million year-to-year primarily due to lower volumes and higher operating expenses on our South Texas System and lower equity in income from our investment in Seaway. The pipeline assets owned by Seaway experienced lower volumes and average fees during 2009 compared to 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $180.5 million for 2009 compared to $187.0 million for 2008, a $6.5 million year-to-year decrease. Results for 2009 include $39.7 million of gains related to insurance proceeds compared to $0.2 million of such gains in 2008. Results for 2009 include $135.3 million of aggregate charges related to our dissociation from TOPS. As discussed in the following paragraphs, gross operating margin from this business segment increased $89.3 million year-to-year excluding the effects of gains from insurance proceeds and charges related to TOPS.

Gross operating margin from our offshore crude oil pipeline business was $79.3 million for 2009 compared to $35.1 million for 2008. The $44.2 million year-to-year increase was primarily due to the start-up of our Shenzi crude oil pipeline in April 2009 and higher transportation volumes on the crude oil pipeline systems owned by Cameron Highway and Poseidon. Total offshore crude oil transportation volumes were 308 MBPD during 2009 versus 169 MBPD during 2008.

Gross operating margin from our offshore natural gas pipeline business was $54.2 million for 2009 compared to $6.9 million for 2008, a $47.3 million year-to-year increase. Offshore natural gas transportation volumes were 1,420 BBtus/d during 2009 versus 1,408 BBtus/d during 2008. Gross operating margin from our Independence Trail pipeline for 2009 increased $39.8 million over 2008. Results for the Independence Trail Pipeline for 2008 were negatively impacted by expenses and downtime associated with flex joint repairs. Collectively, gross operating margin from our other offshore natural gas pipelines increased $7.5 million year-to-year primarily due to hurricane-related property damage repair expenses during 2008.

Gross operating margin from our offshore platform services business was $142.6 million for 2009 compared to $144.8 million for 2008, a $2.2 million year-to-year decrease. Gross operating margin from our Independence Hub platform increased $12.1 million year-to-year primarily due to an increase in natural gas processing volumes during 2009. Our Independence Hub platform experienced reduced volumes and downtime during 2008 in connection with flex joint repairs on the Independence Trail Pipeline. Collectively, gross operating margin from our other offshore platforms and related assets decreased $14.3 million year-to-year primarily due to (i) lower natural gas and crude oil processing volumes at our Marco Polo platform as a result of prolonged hurricane-related operational disruptions and (ii) the expiration of demand fee revenues at our Marco Polo and Falcon platforms. On a net basis, platform natural gas processing volumes increased to 700 MMcf/d during 2009 compared to 632 MMcf/d during 2008 and platform crude oil processing volumes decreased to 12 MBPD during 2009 compared to 15 MBPD during 2008.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $364.7 million for 2009 compared to $374.9 million for 2008, a $10.2 million year-to-year decrease.

Gross operating margin from octane enhancement was $11.5 million for 2009 compared to a loss of $11.3 million for 2008, a $22.8 million year-to-year increase. Gross operating margin for 2008 was negatively impacted by facility downtime, reduced volumes and higher operating expenses as a result of operational issues and the effects of

Hurricane Ike.

Table of Contents

Gross operating margin from propylene fractionation and related activities was $89.6 million for 2009 compared to $87.2 million for 2008. The $2.4 million year-to-year increase in gross operating margin is largely due to higher propylene sales volumes during 2009 relative to 2008. Propylene fractionation volumes increased to 68 MBPD during 2009 from 58 MBPD during 2008.

Gross operating margin from butane isomerization was $76.2 million for 2009 compared to $95.9 million for 2008. The $19.7 million year-to-year decrease in gross operating margin is attributable to lower revenues from the sale of plant by-products due to lower commodity prices. Butane isomerization volumes increased to 97 MBPD during 2009 from 86 MBPD during 2008.

Gross operating margin from refined products pipelines and related activities was $124.7 million for 2009 compared to $132.9 million for 2008, an $8.2 million year-to-year decrease. Gross operating margin for 2009 includes $28.7 million of expense to accrue a liability for pipeline transportation deficiency fees owed to a third-party. Gross operating margin from the remainder of this business increased $20.5 million primarily due to increased revenue from product sales, lower operating expenses and higher average fees on our Products Pipeline System during 2009 relative to 2008. Transportation volumes on our refined products pipelines were 682 MBPD during 2009 compared to 702 MBPD during 2008.

Gross operating margin from marine transportation and other services was $62.7 million for 2009 compared to $70.2 million for 2008, a $7.5 million year-to-year decrease. Gross operating margin from marine transportation decreased $4.8 million year-to-year due to higher operating expenses and lower day rate revenues during 2009 relative to 2008. These factors more than offset gross operating margin generated by the acquisition of 19 push boats and 28 barges in June 2009. Gross operating margin from the distribution of lubrication oils and specialty chemicals decreased $2.7 million year-to-year primarily due to lower margins from the sale of specialty chemicals and higher operating expense during 2009 compared to 2008.

Other Investments. Gross operating margin from this business segment was $41.1 million for 2009 compared to $31.3 million for 2008, a $9.8 million year-to-year increase. This segment reflects our noncontrolling ownership interests in Energy Transfer Equity and LE GP, both of which are accounted for using the equity method.

According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of $1.11 billion for 2009 compared to $1.10 billion for 2008, for an $11.5 million year-to-year increase. The increase in Energy Transfer Equity's operating income is primarily due to improved retail propane sales margins including the impact of hedging activities, contributions from recently completed growth capital projects (e.g., ETP's Phoenix project and increased intrastate pipeline transportation capacity) and lower fuel costs. The year-to-year increase in operating income attributable to the foregoing was partially offset by lower fuel retention revenues (associated with ETP's intrastate transportation and storage operating activities) as a result of lower average natural gas prices during 2009 relative to 2008. Collectively, all other items included in Energy Transfer Equity's net income increased $6.6 million year-to-year primarily due to changes in the fair value of non-hedged interest rate derivatives, the benefit of which was partially offset by a year-to-year increase in interest expense due to borrowings used to finance growth capital projects. After taking into account noncontrolling interests, income attributable to the partners of Energy Transfer Equity increased to $442.5 million for 2009 from $375.0 million for 2008.

Before the amortization of excess cost amounts, our equity income from Energy Transfer Equity and its general partner was a collective $77.7 million for 2009 versus $65.6 million for 2008. Our equity income from these investments was reduced by $36.6 million and $34.3 million of excess cost amortization during 2009 and 2008, respectively. For additional information regarding our investment in Energy Transfer Equity, see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Liquidity and Capital Resources

At December 31, 2010, we had $65.5 million of unrestricted cash on hand and $1.79 billion of available credit under our revolving credit facilities, including the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners. Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for operating expenses and sustaining capital expenditures using operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities.

We had approximately $13.53 billion in principal outstanding under consolidated debt agreements at December 31, 2010. In May 2010, EPO issued an aggregate of $2.0 billion in principal amount of senior unsecured notes. EPO issued (i) $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes X") at 99.79% of their principal amount, (ii) $1.0 billion in principal amount of 10-year senior unsecured notes ("Senior Notes Y") at 99.701% of their principal amount and (iii) $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes Z") at 99.525% of their principal amount. Net proceeds from the issuance of these senior notes were used (i) to repay EPO's Senior Notes K in June 2010, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes. EPO had borrowed $850.0 million under its Multi-Year Revolving Credit Facility to fund a portion of the cash consideration paid to complete the State Line and Fairplay systems acquisitions in May 2010.

In June 2010, EPO entered into the Amended Acadian LLC Agreement with Duncan Energy Partners. This document reflects the agreement between Duncan Energy Partners and EPO regarding funding arrangements for the Haynesville Extension. This expansion capital project will extend our south Louisiana intrastate natural gas pipeline system, which is owned by Acadian Gas, LLC, into northwest Louisiana and the Haynesville Shale production area. Duncan Energy Partners will fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures. The total budgeted cost of the Haynesville Extension project is approximately $1.56 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at $1.03 billion. In order to fund its capital spending requirements under the Haynesville Extension project, Duncan Energy Partners entered into new senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

In January 2011, EPO issued an aggregate of $1.5 billion in principal amount of senior unsecured notes. EPO issued $750.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes AA") at 99.901% of their principal amount and $750.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes BB") at 99.317% of their principal amount. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Registration Statements

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its future liquidity and capital spending requirements. In August 2007, we filed a universal shelf registration statement (the “2007 Shelf”) with the SEC that allowed us to issue an unlimited amount of debt and equity securities. In July

2010, we filed a new universal shelf registration statement (the "2010 Shelf") with the SEC that replaced the 2007 Shelf, which was set to expire in August 2010. Like the 2007 Shelf, the 2010 Shelf allows us to issue an unlimited amount of debt and equity securities.

The following tables present information regarding our equity and debt offerings made under the 2007 Shelf during 2010. Net cash proceeds from equity offerings under the 2007 Shelf are a component of noncontrolling interest as presented on our Statements of Consolidated Cash Flows and Statements of Consolidated Equity included under Item 8 of this annual report. Dollar amounts presented in the tables are in millions, except offering unit price amounts.

Underwritten Equity Offering	Number of Common Units Issued	Offering Unit Price	Total Net Cash Proceeds
January 2010 underwritten offering (1)	10,925,000	$32.42	$350.3
April 2010 underwritten offering (2)	13,800,000	$35.55	484.6
Total	24,725,000		$834.9

(1) Net cash proceeds from this equity offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general company purposes.
(2) Net cash proceeds from this equity offering were used to pay a portion of the purchase price of the State Line and Fairplay natural gas gathering systems and for general partnership purposes.

Note Series	Issued	Principal Amount
Senior Notes X, 3.70% fixed-rate, due June 2015	May 2010	$400.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	May 2010	1,000.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	May 2010	600.0
Total		$2,000.0

The following table presents information regarding an equity offering made under the 2010 Shelf in December 2010.

Underwritten Equity Offering	Number of Common Units Issued	Offering Unit Price	Total Net Cash Proceeds (in millions)
December 2010 (1)	13,225,000	$41.25	$528.5

(1) Net cash proceeds from this equity offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Duncan Energy Partners has a universal shelf registration statement on file with the SEC that allows it to issue up to $1 billion of debt and equity securities. At December 31, 2010, Duncan Energy Partners could issue approximately $856.4 million of additional equity or debt securities under its registration statement.

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. During the year ended December 31, 2010, we issued 8,204,998 common units in connection with our DRIP, which generated proceeds of $267.7 million from plan participants. Of this amount, affiliates of EPCO accounted for approximately $207.7 million of such reinvestment.

In addition to the DRIP, we have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 1,200,000 common units in connection with our employee unit purchase plan. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the year ended December 31, 2010, we issued 173,055 common units to employees under this plan, which generated proceeds of $6.1 million.

Table of Contents

For information regarding our public debt obligations or partnership equity, see Notes 12 and 13, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Letter of Credit Facilities

At December 31, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities. EPO also had an $85.0 million letter of credit outstanding at December 31, 2010, which reduced the amount available for borrowing under its Multi-Year Revolving Credit Facility.

Credit Ratings

At March 1, 2011, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3 from Moody's Investor Services ("Moody's"); BBB- from Fitch Ratings; and BBB- from Standard and Poor's. In April 2010, Standard and Poor's reaffirmed its corporate credit rating of EPO, revised its outlook for EPO's business from "stable" to "positive," and updated its business risk assessment from "satisfactory" to "strong." EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Based on the debt and equity characteristics of EPO's $1.53 billion of junior subordinated notes (a type of hybrid security), the rating agencies assigned partial equity treatment to such notes. The ratings agencies use this treatment to adjust their credit metrics to gain a clearer economic view of the debt and equity components of our capitalization. Standard and Poor's assigns 50% equity treatment to the junior subordinated notes and Fitch Ratings assigns a 75% equity treatment. In July 2010, Moody's announced revisions to their classification system for hybrid securities. Moody's reduced the equity credit that it assigns to securities such as EPO's junior subordinated notes from 50% to 25%.   We do not believe this revision will affect EPO's investment-grade Baa3 senior unsecured debt rating from Moody's.

A downgrade of EPO's credit ratings could result in our being required to post financial collateral in connection with our guaranty of Centennial's debt, which was $55.5 million at December 31, 2010. Furthermore, from time to time we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO's credit ratings were to be downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods presented (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For Year Ended December 31,		
	2010	2009	2008
Net cash flows provided by operating activities	$2,300.0	$2,410.3	$1,566.4
Cash used in investing activities	3,251.6	1,547.7	3,246.9
Cash provided by (used in) financing activities	961.1	(863.9)	1,695.9

Table of Contents

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstock in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Item 1A of this annual report.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, operating lease expenses paid by EPCO, changes in the fair market value of derivative instruments and equity in income from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt. In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by or used in financing activities generally consists of borrowings and repayments of debt, distributions to partners and noncontrolling interests and proceeds from the issuance of equity securities (particularly to noncontrolling interests). Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of 2010 with 2009

Operating Activities. The $110.3 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) decreased $75.4 million year-to-year. The decrease in operating cash flow is generally due to the timing of cash receipts and disbursements in our operating accounts, partially offset by increased profitability (e.g., our gross operating margin increased $372.1 million year-to-year).

§ Distributions received from unconsolidated affiliates increased $22.6 million year-to-year primarily due to higher distributions received from Poseidon and Promix. In February 2010, we also began receiving distributions from Skelly-Belvieu. See Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our unconsolidated affiliates.

Table of Contents

- § Cash payments for interest increased approximately $71.4 million year-to-year primarily due to an increase in fixed-rate debt obligations. Our average debt principal outstanding for 2010 was $13.23 billion compared to $13.0 billion for 2009.

- § Cash payments for income taxes decreased $13.9 million year-to-year primarily due to higher payments made during 2009 attributable to the Texas Margin Tax and a taxable gain arising from Dixie's sale of certain assets.

Investing Activities. The $1.7 billion increase in cash used for investing activities was primarily due to the following:

- § Cash used for business combinations increased $1.21 billion year-to-year, primarily due to the May 2010 acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion. For additional information regarding this transaction, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- § Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $435.6 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

- § Restricted cash related to our hedging activities increased $35.0 million (a cash outflow) during 2010 due to increases in the margin requirements of our commodity hedging positions. For 2009, restricted cash related to our hedging activities decreased $140.2 million (a cash inflow).

- § Proceeds from asset sales and related transactions increased $102.3 million year-to-year primarily due to insurance proceeds received during the third quarter 2010 related to the disposition of assets and the sale of our entire membership interest in LE GP in December 2010.

Financing Activities. Cash provided by financing activities was $961.1 million for 2010 compared to cash used in financing activities of $863.9 million in 2009. The $1.83 billion change in financing activities was primarily due to the following:

- § Net borrowings under our consolidated debt agreements increased $1.41 billion year-to-year. During 2010, EPO issued $2.0 billion in senior notes (Senior Notes X, Y and Z) offset by the repayment of its $500.0 million of Senior Notes K and $54.0 million Pascagoula Mississippi Business Finance Corporation Loan. In October 2010, Duncan Energy Partners borrowed $400 million under its new term loan to repay and terminate a revolving credit facility and an intercompany note. In general, the amount of indebtedness for Duncan Energy Partners is increasing due to borrowings to fund its obligations in connection with the Haynesville Extension project. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- § Cash distributions paid to partners (i.e., the unitholders of Holdings prior to the Holdings Merger) increased $41.0 million year-to-year due to increases in Holdings' quarterly distribution rates and the number of distribution-bearing units outstanding.

  - § Cash distributions paid to noncontrolling interests increased $156.3 million year-to-year primarily due to increases in the number of Enterprise common units outstanding and its quarterly distribution rates, partially offset by the cessation of cash distributions to the former owners of TEPPCO in connection with the TEPPCO Merger.

- Cash contributions from noncontrolling interests increased $89.5 million year-to-year primarily due to an increase in the offering prices of Enterprise's common units in connection with its equity offerings in 2010 compared to those in 2009. In addition, Duncan Energy Partners issued common units in 2009, which generated $137.4 million in proceeds.

§ Net cash proceeds from the issuance of our common units in December 2010, following the Holdings Merger, were $528.5 million.

Comparison of 2009 with 2008

Operating Activities. The $843.9 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) increased $888.7 million year-to-year. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements. The total year-to-year increase also reflects a $68.9 million increase in cash proceeds from hurricane-related insurance claims. For information regarding cash proceeds from business interruption and property damage insurance claims, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash distributions received from unconsolidated affiliates increased $12.1 million year-to-year, including a $6.2 million increase in distributions received from Energy Transfer Equity.

§ Cash payments for interest increased $56.9 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt principal outstanding for 2009 was $13.0 billion compared to $11.27 billion for 2008.

§ Cash payments for income taxes increased $22.7 million year-to-year primarily due to higher payments made in 2009 for the Texas Margin tax and a taxable gain arising from the sale of certain assets by Dixie.

Investing Activities. The $1.7 billion decrease in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $945.9 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

§ Cash used for business combinations decreased $446.2 million year-to-year. For additional information regarding our business combinations in 2009 and 2008, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Restricted cash related to our hedging activities decreased $140.2 million (a cash inflow) during 2009 primarily due to a reduction in margin requirements related to derivative instruments we utilized. For 2008, restricted cash related to our hedging activities increased $132.8 million (a cash outflow).

Financing Activities. Cash used in financing activities was $863.9 million for 2009 compared to cash provided by financing activities of $1.7 billion in 2008. The $2.56 billion change in financing activities was primarily due to the following:

§ Net repayments under our consolidated debt agreements of $272.5 million in 2009 compared to net borrowings under our consolidated debt agreements of $2.74 billion in 2008. During 2008, EPO and TEPPCO issued a combined $2.6 billion in principal amount of senior notes. For information regarding our consolidated debt obligations see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

§ Cash distributions paid to partners (i.e., the unitholders of Holdings prior to the Holdings Merger) increased $53.6 million year-to-year primarily due to increases in Holdings' quarterly distribution rates.

§ Distributions paid to noncontrolling interests increased $140.0 million year-to-year primarily due to increases in the number of units outstanding and quarterly distribution rates of Enterprise, TEPPCO (prior to the TEPPCO Merger), and Duncan Energy Partners.

.

§ Contributions from noncontrolling interests increased $567.8 million year-to-year primarily due to net cash proceeds that Enterprise and Duncan Energy Partners received from common unit offerings in 2009.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins in the Rocky Mountains and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale and Eagle Ford Shale producing regions.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2010	2009	2008
Capital spending for business combinations:			
State Line and Fairplay Systems acquisition	$1,214.5	$--	$--
Great Divide Gathering System acquisition	--	--	125.2
Cenac and Horizon acquisition	--	--	345.7
Other business combinations	99.4	107.3	82.6
Total	1,313.9	107.3	553.5
Capital spending for property, plant and equipment, net: (1)			
Growth capital projects (2)	1,766.2	1,373.9	2,249.5
Sustaining capital projects (3)	235.9	192.6	262.9
Total	2,002.1	1,566.5	2,512.4
Capital spending for intangible assets:			
Acquisition of intangible assets	--	1.4	5.8
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates	8.0	19.6	64.7
Total capital spending	$3,324.0	$1,694.8	$3,136.4

(1) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $38.7 million, $17.8 million and $27.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. Growth and sustaining capital amounts presented in the table are presented net of related contributions in aid of construction costs.

(2) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.
(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

Table of Contents

Based on information currently available, we estimate our consolidated capital spending for 2011 will be approximately $3.7 billion, which includes estimated expenditures of $3.4 billion for growth capital projects and acquisitions and $260.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our currently announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2010, we had approximately $795.7 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects at our Mont Belvieu complex and those involving our natural gas pipeline projects in the Eagle Ford Shale, Haynesville Shale and Piceance Basin.

Pipeline Integrity Costs

Our pipelines are subject to pipeline safety programs administered by the DOT. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2010	2009	2008
Expensed	$39.4	$44.9	$55.4
Capitalized	40.4	37.7	86.2
Total	$79.8	$82.6	$141.6

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $93.3 million in 2011.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Table of Contents

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

§ changes in laws and regulations that limit the estimated economic life of an asset;

§ changes in technology that render an asset obsolete;

§ changes in expected salvage values; or

§ significant changes in the forecast life of proved reserves of applicable resource basins, if any.

At December 31, 2010 and 2009, the net book value of our property, plant and equipment was $19.33 billion and $17.69 billion, respectively. We recorded $745.7 million, $678.1 million and $595.9 million in depreciation expense for the years ended December 31, 2010, 2009 and 2008, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. Long-lived assets with carrying values that are not expected to be recovered through forecast future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. Equity method investments with carrying values that are not expected to be recovered through expected future cash flows are written down to their estimated fair values. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

113

Table of Contents

During 2010 and 2009, we recognized non-cash asset impairment charges related to property, plant and equipment of $8.4 million and $29.4 million, respectively, which are a component of operating costs and expenses. No such non-cash asset impairment charges were recorded in 2008.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 6 and 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon a number of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent customer bases we acquired in connection with business combinations. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement or the natural gas transportation contracts of our Val Verde and Jonah systems. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

§ the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline or other asset);

§ any legal or regulatory developments that would impact such contractual rights; and

§ any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment; we would be required to reduce the asset's carrying value to fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2010 and 2009, the carrying value of our intangible asset portfolio was $1.84 billion and $1.06 billion, respectively. We recorded $137.6 million, $119.9 million and $130.0 million in amortization expense associated with our intangible assets for the years ended December 31, 2010, 2009 and 2008, respectively.

For additional information regarding our intangible assets, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill for impairment at the beginning of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit.

Such assumptions include:

§ discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors;

§ long-term growth rates for cash flows beyond the discrete forecast period; and

§ appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of the goodwill to its implied fair value. Based on our most recent goodwill impairment testing, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

At December 31, 2010 and 2009, the carrying value of our goodwill was $2.11 billion and $2.02 billion, respectively. We recorded goodwill impairment charges of $1.3 million during 2009. No such impairment charges were recorded in 2010 or 2008. For additional information regarding our goodwill, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met:

§ persuasive evidence of an exchange arrangement exists;

§ delivery has occurred or services have been rendered;

§ the buyer's price is fixed or determinable; and

§ collectibility is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). For additional information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of

Table of Contents

operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Reserves for Environmental Matters

Our business activities are subject to various federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2010, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

At December 31, 2010 and 2009, we had a liability for environmental remediation of $12.4 million and $16.7 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We have recorded our best estimate of the cost of remediation activities. See Notes 2 and 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding environmental matters.

Natural Gas Imbalances

In the natural gas pipeline transportation business, volumetric imbalances frequently result from differences in natural gas received from and delivered to customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of such settlements are through in-kind arrangements whereby an imbalance volume is incrementally delivered to or received from a customer over several periods. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out at negotiated values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated (dollars in millions):

	December 31,	
	2010	2009
Natural gas imbalance receivables (1)	$22.8	$24.1
Natural gas imbalance payables (2)	31.9	19.0

(1) Reflected as a component of “Accounts and notes receivable – trade” on our Consolidated Balance Sheets included under Item 8 of this annual report.
(2) Reflected as a component of “Accrued product payables” on our Consolidated Balance Sheets included under Item 8 of this annual report.

Table of Contents

Other Items

Duncan Energy Partners

For information regarding our relationship with Duncan Energy Partners, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. For additional information regarding insurance matters, see Note 19 of the Notes Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2010 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of debt obligations (1)	$13,526.5	$732.3	$3,354.0	$1,800.0	$7,640.2
Estimated cash payments for interest (2)	$13,502.5	$753.8	$1,328.3	$1,047.7	$10,372.7
Operating lease obligations (3)	$375.8	$48.2	$84.6	$57.2	$185.8
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$1,586.6	$806.2	$358.0	$153.6	$268.8
NGLs	$5,331.8	$2,597.8	$1,992.5	$734.1	$7.4
Crude oil	$450.8	$450.8	$--	$--	$--
Petrochemicals & refined products	$501.3	$458.3	$43.0	$--	$--
Other	$117.6	$24.9	$26.8	$24.8	$41.1
Underlying major volume commitments:					
Natural gas (in BBtus)	375,545	190,304	84,891	36,500	63,850
NGLs (in MBbls)	98,410	49,060	35,751	13,495	104
Crude oil (in MBbls)	5,169	5,169	--	--	--
Petrochemicals & refined products (in MBbls)	5,616	5,094	522	--	--
Service payment commitments (5)	$656.3	$95.2	$150.6	$127.9	$282.6
Capital expenditure commitments (6)	$795.7	$795.7	$--	$--	$--
Other long-term liabilities (7)	$220.6	$--	$91.3	$18.6	$110.7
Total	$37,065.5	$6,763.2	$7,429.1	$3,963.9	$18,909.3

(1) Represents our scheduled future maturities of consolidated debt principal obligations. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2010. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2010 to determine the estimated cash payments. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for the weighted-average variable interest rates charged in 2010 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2010. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Subordinated Notes A (due August 2066), $682.7 million Junior Subordinated Notes B (due January 2068), $300.0 million Junior Subordinated Notes C (due June 2067) and TEPPCO Junior Subordinated Notes (due June 2067). Our estimated cash payments for interest assume that these subordinated notes are not called prior to their respective maturity dates. We applied the current fixed interest rate through the respective maturity date for each junior subordinated note to determine the estimated cash payments for interest.

(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with affiliates of EPCO and (iii) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services under the terms of each agreement at December 31, 2010. The estimated payment obligations are based on contractual prices in effect at

December 31, 2010 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.
(5) Represents long and short-term commitments to pay service providers primarily for obligations under firm pipeline transportation contracts on pipelines we do not directly own.
(6) Represents short-term unconditional payment obligations relating to our capital projects, including our share of those of our unconsolidated affiliates, for services to be rendered or products to be delivered.
(7) As reflected on our Consolidated Balance Sheet at December 31, 2010, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations, deferred revenues and accrued obligations for pipeline transportation deficiency fees and interest rate derivative instruments.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Off-Balance Sheet Arrangements

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2010, Poseidon's debt obligations consisted of $92.0 million outstanding under its $150.0 million variable-rate revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets. Poseidon expects to fund the repayment of its revolving credit facility (including accrued interest) with a variety of sources (either separately or in combination) including operating cash flows, refinancing agreements or cash contributions from its joint venture partners.

Evangeline. At December 31, 2010, Evangeline's debt obligations consisted of a $3.2 million subordinated note payable due in 2011. Evangeline expects to fund the repayment of its debt obligations (including accrued interest) using operating cash flows.

Centennial. At December 31, 2010, Centennial's debt obligations consisted of $110.9 million borrowed under a master shelf loan agreement through two private placements, with interest rates ranging from 7.99% to 8.09%. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners. Specifically, we and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial were to default on its debt obligations, our estimated payment obligation would be $55.5 million based on amounts outstanding at December 31, 2010.

Energy Transfer Equity. At December 31, 2010, Energy Transfer Equity had approximately $9.4 billion of consolidated debt obligations outstanding. The majority of these amounts relate to senior note obligations of Energy Transfer Equity (on a standalone basis), ETP and RGNC and revolving credit agreements of ETP and RGNC. Based on information contained in the SEC filings of Energy Transfer Equity, the future maturities of their consolidated long-term debt at December 31, 2010 are as follows: $35.3 million, 2011; $825.7 million, 2012; $373.1 million, 2013; $729.1 million, 2014; $755.9 million, 2015 and $6.7 billion, thereafter.

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report as well as Item 13 of this annual report.

119

Table of Contents

Non-GAAP Reconciliations

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2010	2009	2008
Total segment gross operating margin	$3,253.0	$2,880.9	$2,640.3
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(936.3)	(809.3)	(725.4)
Non-cash asset impairment charges	(8.4)	(33.5)	--
Operating lease expenses paid by EPCO	(0.7)	(0.7)	(2.0)
Gains from asset sales and related transactions in operating costs and expenses	44.4	--	4.0
General and administrative costs	(204.8)	(182.8)	(144.8)
Operating income	2,147.2	1,854.6	1,772.1
Other expense, net	(737.4)	(689.0)	(596.0)
Income before provision for income taxes	$1,409.8	$1,165.6	$1,176.1

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation (e.g., the EPCO retained leases); (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interest.

Recent Accounting Developments

The following recent accounting developments will or may affect our future financial statements:

§ Disclosure of Supplementary Pro Forma Information for Business Combinations;

§ Roadmap to Adoption of International Reporting Standards; and

§ Fair Value Measurements.

For additional information regarding these recent accounting developments, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain anticipated transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

See Note 6 of the Notes to the Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our interest rate swaps outstanding at December 31, 2010:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.6%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

In January 2011, EPO entered into ten additional interest rate swaps with an aggregate notional amount of $750.0 million related to the issuance of Senior Notes AA.

The following tables show the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolios at the dates presented (dollars in millions):

		Swap Fair Value at		
Scenario	Resulting Classification	December 31, 2009	December 31, 2010	January 31, 2011
FV assuming no change in underlying interest rates	Asset	$18.2	$35.3	$42.6
FV assuming 10% increase in underlying interest rates	Asset	12.3	36.1	35.7

FV assuming 10% decrease in underlying interest rates	Asset	24.1	34.6	49.6

The following table summarizes our forward starting interest rate swaps outstanding at December 31, 2010, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	3 forward starting swaps	$250.0	2/11	3.7%	Cash flow hedge
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	3 forward starting swaps	$150.0	8/12	4.0%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

Table of Contents

The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting interest rate swap portfolio at the dates presented (dollars in millions):

		Swap Fair Value at		
Scenario	Resulting Classification	December 31, 2009	December 31, 2010	January 31, 2011
FV assuming no change in underlying interest rates	Asset	$21.0	$19.2	$40.5
FV assuming 10% increase in underlying interest rates	Asset	31.1	80.0	94.9
FV assuming 10% decrease in underlying interest rates	Asset (Liability)	10.5	(44.3)	(16.6)

In January 2011, we settled the three forward starting interest rate swaps with a notional amount of $250 million for a loss of $5.7 million.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. We may use commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts to mitigate such risks.

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2011, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At December 31, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $365.2 million on 11.4 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011. At January 31, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of $377.0 million on 11.6 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Certain basis swaps, basis spread options and other financial derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

Table of Contents

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2010:

	Volume (1)		Accounting
Derivative Purpose	Current	Long-Term (2)	Treatment
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	35.8 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.8 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (4)	n/a	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	2.8 MMBbls	0.2 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	13.4 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	5.9 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	6.9 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	2.6 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of refined products	3.7 MMBbls	0.2 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.4 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	2.1 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	474.3 Bcf	58.9 Bcf	Mark-to-market
Refined products risk management activities (6)	2.0 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	0.1 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	2.8 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives included in the long-term column is December 2013.

(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.

(4) Forecasted purchase volumes of NGLs under Octane enhancement and forecasted sales of NGL volumes under Natural gas processing exclude 1.7 MMBbls and 2.8 MMBbls, respectively, of additional hedges executed under contracts that have been designated as normal purchase/sales agreements.
(5) Current and long-term volumes include approximately 162.5 Bcf and 6.9 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

We assess the risk of our commodity derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to these portfolios measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted

Table of Contents

market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2009	December 31, 2010	January 31, 2011
FV assuming no change in underlying commodity prices	Liability	$(1.5)	$(12.4)	$(13.3)
FV assuming 10% increase in underlying commodity prices	Liability	(7.0)	(21.5)	(18.3)
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	4.1	(3.3)	(8.2)

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2009	December 31, 2010	January 31, 2011
FV assuming no change in underlying commodity prices	Liability	$(9.2)	$(40.3)	$(60.4)
FV assuming 10% increase in underlying commodity prices	Liability	(43.2)	(104.5)	(121.4)
FV assuming 10% decrease in underlying commodity prices	Asset	24.8	24.0	0.6

The following table shows the effect of hypothetical price movements on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2009	December 31, 2010	January 31, 2011
FV assuming no change in underlying commodity prices	Asset	$2.0	$1.8	$2.5
FV assuming 10% increase in underlying commodity prices	Asset (Liability)	2.0	(0.3)	1.1
FV assuming 10% decrease in underlying commodity prices	Asset	2.1	4.0	3.9

Foreign Currency Derivative Instruments

Prior to January 1, 2011, we were exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. In order to manage this risk, we entered into foreign exchange purchase contracts to lock in a currency exchange rate. At December 31, 2010, we had entered into offsetting foreign currency derivative instruments and our foreign currency portfolio had a zero notional amount of Canadian dollars. The fair market value of these derivative instruments was an asset of $0.2 million at December 31, 2010 and the total portfolio is accounted for using mark-to-market accounting.

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, petrochemicals and other hydrocarbons with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "Other Items - Contractual Obligations" included under Item 7 of this annual report.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the independent registered public accounting firm's report of Deloitte & Touche LLP ("Deloitte & Touche") begin on page F-1 of this annual report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of our general partner's CEO (our principal executive officer) and our general partner's chief financial officer (our principal financial officer) (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this annual report, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2010, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report.

Table of Contents

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2010

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Enterprise Products Partners' management and Board of Directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners' internal control over financial reporting as of December 31, 2010. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2010, Enterprise Products Partners' internal control over financial reporting is effective based on those criteria.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of our general partner. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners' internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Enterprise Products Partners' significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is included within this Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2011.

/s/ Michael A. Creel		/s/ W. Randall Fowler	
Name:	Michael A. Creel	Name:	W. Randall Fowler
Title:	Chief Executive Officer of our general partner, Enterprise Products Holdings LLC	Title:	Chief Financial Officer of our general partner, Enterprise Products Holdings LLC

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2010. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's Board of Directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Table of Contents

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated operations, comprehensive income, cash flows, and equity as of and for the year ended December 31, 2010 of the Company and our report dated March 1, 2011 expresses an unqualified opinion on those financial statements and includes an explanatory paragraph concerning the effects of the merger between Enterprise GP Holdings L.P. and the Company on November 22, 2010.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors (the "Board") and executive officers of Enterprise GP. For a description of the ASA, see "Relationship with EPCO and Affiliates – EPCO ASA" in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The executive officers of our general partner are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of our general partner. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of our general partner serves until such member's death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2010 were Messrs. Creel, Cunningham, Fowler (from January 1, 2010 until May 21, 2010), Bachmann and Teague.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of our general partner maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax

Table of Contents

matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element for strong governance is independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Ross, Rampacek, Andress, McMahen, Smith and Barnett are "independent" directors under the NYSE rules.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, CFO, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the code (and thus accountability for adherence to the code).

Governance guidelines, together with applicable committee charters, provide the framework for effective governance. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit, Conflicts and Governance ("ACG") Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

We provide investors access to current information relating to our governance procedures and principles, including the Code of Conduct, the Governance Guidelines of Enterprise Products Partners and other matters, through our Internet website, www.epplp.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on its ACG Committee. The members of the ACG Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

129

Table of Contents

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG Committee are Messrs. Ross, McMahen and Barnett. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The ACG Committee's duties are addressing audit and conflicts-related items and general corporate governance matters. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

§ reviewing potential conflicts of interests, including related party transactions;

§ monitoring the integrity of our financial reporting process and related systems of internal control;

§ ensuring our legal and regulatory compliance and that of Enterprise GP;

§ overseeing the independence and performance of our independent public accountant;

§ approving all services performed by our independent public accountant;

§ providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;

§ encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

§ reviewing areas of potential significant financial risk to our businesses; and

§ approving awards granted under our long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the ACG Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the ACG Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The ACG Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

From a governance standpoint, the primary duties and responsibilities of the ACG Committee are to recommend to the Board a set of governance principles applicable to us and review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.epplp.com. You may also contact our Investor Relations department at (866) 230-0745 for a printed copy of this document free of charge.

Table of Contents

NYSE Corporate Governance Listing Standards

On March 23, 2010, Michael A. Creel, our CEO, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 23, 2010.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the ACG Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors and executive officers of Enterprise GP at March 1, 2011. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams	49	Director
Dr. Ralph S. Cunningham	70	Director and Chairman of the Board
Richard H. Bachmann	58	Director
Thurmon M. Andress	77	Director
Charles E. McMahen (2,3)	71	Director
Edwin E. Smith	79	Director
Michael A. Creel (1)	57	Director, President and CEO
A. James Teague (1)	65	Director, Executive Vice President and Chief Operating Officer
E. William Barnett (2)	77	Director
Charles M. Rampacek	67	Director
Rex C. Ross (2)	67	Director
W. Randall Fowler (1)	54	Executive Vice President and CFO
William Ordemann (1)	51	Executive Vice President
Lynn L. Bourdon, III (1)	48	Senior Vice President
Bryan F. Bulawa (1)	41	Senior Vice President and Treasurer
G. R. Cardillo (1)	53	Senior Vice President
James M. Collingsworth (1)	56	Senior Vice President
Stephanie C. Hildebrandt (1)	46	Senior Vice President, General Counsel and Secretary
Mark A. Hurley (1)	52	Senior Vice President
Michael J. Knesek (1)	56	Senior Vice President, Controller and Principal Accounting Officer

Christopher Skoog (1)	47	Senior Vice President
Thomas M. Zulim (1)	52	Senior Vice President

(1) Executive officer
(2) Member of ACG Committee
(3) Chairman of ACG Committee

The following information presents a brief history of the business experience of our directors and executive officers of Enterprise GP serving as of March 1, 2011:

Randa Duncan Williams. Ms. Williams was elected a Director of Enterprise GP in May 2007. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Williams has served as a Director of EPCO since February 1991. Prior to joining EPCO in 1994, Ms.

Table of Contents

Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. She currently serves on the boards of directors of Encore Bancshares and Encore Bank and also serves on the board of trustees for numerous charitable organizations.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of Enterprise GP in August 2007 and as Chairman of the Board upon consummation of the Holdings Merger. Dr. Cunningham served as the President and CEO of Enterprise GP from August 2007 until November 2010. He served as a director of EPGP from February 2006 to May 2010, having previously served as a director of EPGP from April 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim CEO from June 2007 to August 2007. Dr. Cunningham served as a director of DEP GP from August 2007 to May 2010. He served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected Vice Chairman of EPCO in May 2010 and a director in March 2006, having previously served as Group Vice Chairman of EPCO from December 2007 to May 2010 and as a Director of EPCO from 1987 to 1997. He serves as a director of Tetra Technologies, Inc. and Agrium, Inc. In addition, Dr. Cunningham serves as a Director and the Chairman of the Safety, Health and Responsibility Committee of Cenovus Energy Inc. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he served as President and CEO since 1995. Dr. Cunningham also served as a Director of LE GP, LLC (the general partner of Energy Transfer Equity, L.P.) from December 2009 to November 2010.

Richard H. Bachmann. Mr. Bachmann served as an Executive Vice President and the Chief Legal Officer of EPGP from February 1999 until November 2010 and served as Secretary of EPGP from November 1999 until November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010. Mr. Bachmann served as Executive Vice President of Enterprise GP from April 2005 until November 2010, and has served as a director of Enterprise GP since February 2006. He previously served as Chief Legal Officer and Secretary of Enterprise GP from April 2005 to May 2010.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a Director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a Director of DEP GP from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance Committees of Constellation Energy Partners LLC and as the Chairman of its Conflicts Committee.

Thurmon M. Andress. Mr. Andress was elected a Director of Enterprise GP in November 2006. Mr. Andress serves as the Managing Director — Houston for Breitburn Energy Company L.P. and is a former member of its Board of Directors. In 1990, he founded Andress Oil & Gas Company, serving as its President and CEO until it merged with Breitburn Energy Company L.P. in 1998. In 1982, he founded Bayou Resources, Inc. a publicly traded energy company that was sold in 1987. From 2002 through December 2009, Mr. Andress served as a member of the Board of Directors of Edge Petroleum Corp. (including its Governance and Compensation Committees). In October 2009, Edge Petroleum Corp. filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc. Mr. Andress is currently a member of the National Petroleum Council (including its Board) and serves on the Board of Governors of Houston for the Independent Petroleum Association of America. In 1993, Mr. Andress was inducted into All American Wildcatter's, a 100-member organization dedicated to American oil and gas explorationists and producers.

Charles E. McMahen. Mr. McMahen was elected a Director of Enterprise GP in August 2005 and serves as Chairman of its Audit, Conflicts and Governance Committee. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of

Table of Contents

Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank, since 2001. He also served as chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

Edwin E. Smith. Mr. Smith was elected a Director of Enterprise GP in August 2005. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith serves as a director of Encore Bank and previously served as a director of EPCO from 1987 until 1997.

Michael A Creel. Mr. Creel was elected President and CEO and a Director of Enterprise GP upon the consummation of the Holdings Merger. He served as a Director of EPGP from February 2006 to November 2010 and President and CEO of EPGP from August 2007 to November 2010. Mr. Creel served as CFO of EPGP from June 2000 to August 2007, and as an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

In May 2010, Mr. Creel was elected Vice Chairman of EPCO, having previously served as Group Vice Chairman and CFO of EPCO since December 2007. Prior to these elections, Mr. Creel served as EPCO's Chief Operating Officer from April 2005 to December 2007 and as its CFO from June 2000 to April 2005. He has served as a Director of EPCO since December 2007. Mr. Creel previously served as a director of Enterprise GP from October 2009 to May 2010 and as a director of DEP GP from October 2006 to May 2010. He previously served as President, CEO and a Director of Enterprise GP from August 2005 through August 2007. From October 2006 to August 2007, he served as Executive Vice President and CFO of DEP GP. From October 2005 through December 2009, Mr. Creel served as a director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

A. James Teague. Mr. Teague was elected an Executive Vice President and the Chief Operating Officer and a Director of Enterprise GP upon the consummation of the Holdings Merger. He served as Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a Director from July 2008 to November 2010 and as Chief Operating Officer from September 2010 to November 2010. In addition, he served as EPGP's Chief Commercial Officer from July 2008 until September 2010. He has served as Executive Vice President and Chief Commercial Officer of DEP GP since July 2008. He previously served as a Director of DEP GP from July 2008 to May 2010 and as a Director of Enterprise GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

E. William Barnett. Mr. Barnett was elected a Director of Enterprise GP upon the consummation of the Holdings Merger and is a member of its ACG Committee. He served as a Director of EPGP from March 2005 to November 2010, and he served as Chairman of its ACG Committee. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for 14 years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation; a director of St. Luke's Episcopal Hospital; and a director Emeritus and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a director of RRI Energy, Inc. (a publicly traded electric services company) and Westlake Chemical Corporation (a publicly traded chemical company). Mr. Barnett is Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University and a director

Table of Contents

Emeritus and former Chairman of the Greater Houston Partnership. Mr. Barnett served as a Trustee Emeritus of the Baylor College of Medicine from 1993 until 2004.

Charles M. Rampacek. Mr. Rampacek was elected a Director of Enterprise GP upon the consummation of the Holdings Merger. He served as a Director of EPGP from October 2006 to November 2010 and was a member of its ACG Committee. Mr. Rampacek is currently a business and management consultant in the energy industry. Mr. Rampacek served as Chairman, CEO and President of Probex Corporation ("Probex"), an energy technology company that developed a proprietary used oil recovery process, from 2000 until his retirement in 2003. Prior to joining Probex, Mr. Rampacek was President and CEO of Lyondell-Citgo Refining L.P., a manufacturer of petroleum products, from 1996 through 2000. From 1982 to 1995, he held various executive positions with Tenneco Inc. and its energy-related subsidiaries, including President of Tenneco Gas Transportation Company, Executive Vice President of Tenneco Gas Operations and Senior Vice President of Refining and Supply.

Mr. Rampacek also spent 16 years with Exxon Company USA, where he held various supervisory and management positions. Mr. Rampacek has been a director of Flowserve Corporation since 1998 and is a member of its Audit Committee and its Organization and Compensation Committee. Mr. Rampacek also serves as a director of Cenovus Energy Inc. (a Canadian publicly traded oil company) and is a member of its Nominating and Governance Committee, Reserves Committee, and Safety, Environment and Responsibility Committee.

In 2005, two complaints requesting recovery of certain costs were filed against former officers and directors of Probex as a result of the bankruptcy of Probex in 2003. These complaints were defended under Probex's director and officer insurance with American International Group, Inc. ("AIG") and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt of which Mr. Rampacek was one. A settlement of $2,000 was reached and approved by the bankruptcy court in the first half of 2006.

Rex C. Ross. Mr. Ross was elected a Director of Enterprise GP upon the consummation of the Holdings Merger and is a member of its ACG Committee. He served as a Director of EPGP from October 2006 to November 2010 and was a member of its Audit, Conflicts and Governance Committee. Until July 2009, Mr. Ross served as a Director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the United States. Prior to his executive retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the Board of Directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Governance & Nominating Committee and Compensation Committee.

W. Randall Fowler. Mr. Fowler was elected an Executive Vice President and the CFO of Enterprise GP in August 2007 and previously served as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He was also elected President and CEO of DEP GP in April 2010, having previously served as Executive Vice President and CFO of DEP GP since August 2007. He has served as a Director of DEP GP since September 2006. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a Director of EPGP and of Enterprise GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Enterprise GP from August 2005 to August 2007.

Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010 and has served as a Director since December 2007. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as CFO from April 2005 to December 2007. Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise as Director of

Investor Relations in January 1999. Mr. Fowler also serves as Chairman of the Board of the National Association of Publicly Traded Partnerships. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Table of Contents

William Ordemann. Mr. Ordemann was elected an Executive Vice President of Enterprise GP in August 2007. He also served as EPGP's Chief Operating Officer from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. He was also elected an Executive Vice President of DEP GP in August 2007. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining Enterprise, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Lynn L. Bourdon, III. Mr. Bourdon was elected a Senior Vice President (Supply & Marketing) of Enterprise GP upon the consummation of the Holdings Merger. He served as Senior Vice President, Supply & Marketing of EPGP from 2004 to November 2010 after serving as Senior Vice President and Chief Commercial Officer with Orion Refining Corporation from 2001 to 2003 and as a Partner in En*Vantage, Inc. from 1999 to 2001. In May 2003, Orion Refining Corporation filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code. Mr. Bourdon served as Senior Vice President of Commercial Operations for PG&E Gas Transmission from 1997 to 1999 and Vice President, NGL Marketing & Development at the predecessor company, Valero, from 1996 to 1997. Earlier in his career, Mr. Bourdon served 12 years with Dow Chemical Company in the engineering, business and commercial areas.

Bryan F. Bulawa. Mr. Bulawa was elected a Senior Vice President and the Treasurer of Enterprise GP in October 2009, Senior Vice President, CFO and Treasurer of DEP GP in April 2010 and a Director of DEP GP in February 2011. He previously served as Senior Vice President and Treasurer of EPGP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009. He has also served as Senior Vice President and Treasurer of EPCO since May 2010. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

G. R. Cardillo. Mr. Cardillo was elected a Senior Vice President (Propylene and Marine) of Enterprise GP in February 2011. Mr. Cardillo joined us in connection with our purchase of certain petrochemical storage and propylene fractionation assets from affiliates of Ultramar Diamond Shamrock Corp. and Koch Industries Inc. ("Diamond Koch") in 2002. From 2000 to 2002, Mr. Cardillo served as a Vice President in charge of propylene commercial activities for Diamond Koch. Mr. Cardillo served as a Vice President of EPGP from November 2004 to November 2010 and of Enterprise GP from November 2010 to February 2011. Mr. Cardillo has been an integral part of our Petrochemicals management team since joining us in 2002 and assumed leadership of this commercial function in June 2008. He assumed leadership of our marine services operations in July 2010.

James M. Collingsworth. Mr. Collingsworth was elected a Senior Vice President (Regulated Pipelines & Gas Storage) of Enterprise GP upon the consummation of the Holdings Merger. He served as Vice President of EPGP from November 2001 to November 2002 and Senior Vice President from November 2002 until November 2010. Previously, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001. Prior to joining Texaco, Mr. Collingsworth was director of feedstocks for Rexene Petrochemical Company from 1988 to 1991 and served in the MAPCO, Inc. organization from 1973 to 1988 in various capacities including customer service and business development manager of the Mid-America and Seminole pipelines.

Stephanie C. Hildebrandt. Ms. Hildebrandt was elected a Senior Vice President and the General Counsel of Enterprise GP in May 2010 and served as Senior Vice President and General Counsel of EPGP from May 2010 to November 2010. Ms. Hildebrandt has also served as Senior Vice President, Chief Legal Officer and Secretary of DEP

GP since April 2010, having previously served as Vice President and General Counsel of EPGP since October 2009, as Vice President and Deputy General Counsel of EPGP from 2006

Table of Contents

to 2009, and as Deputy General Counsel of EPGP from 2004 to 2006. Prior to joining Enterprise, Ms. Hildebrandt practiced law for three years at El Paso Corporation and for 12 years at Texaco Inc.

Mark A. Hurley. Mr. Hurley was elected a Senior Vice President (Crude Oil & Offshore) of Enterprise GP upon consummation of the Holdings Merger. He previously served as Senior Vice President, Crude Oil & Offshore, for EPGP from March 2010 to November 2010. Prior to joining Enterprise, Mr. Hurley was a Shell employee and recently served as President of Shell Pipeline Company, a crude oil, refined products and natural gas energy storage and transportation company. Mr. Hurley began his career with Shell in process engineering positions at refineries in Louisiana and California. During his tenure with Shell, he held key leadership roles in refinery and lubricant plant operations, marketing, sales, product supply planning and trading, with both U.S. and global responsibilities. As President of Shell Pipeline Company for five years, Mr. Hurley had ultimate responsibility for profitability, operations, strategy, business development and capital project development.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected a Senior Vice President of Enterprise GP in August 2005. From February 2005 to November 2010, Mr. Knesek served as Senior Vice President of EPGP, having previously served as a Vice President of EPGP since August 2000. Mr. Knesek has been the Principal Accounting Officer and Controller of Enterprise GP since August 2005 and of DEP GP since September 2006. He served as the Principal Accounting Officer and Controller of EPGP from August 2000 to November 2010. He has served as Senior Vice President of DEP GP since September 2006. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Christopher R. Skoog. Mr. Skoog was elected Senior Vice President (Natural Gas Services & Marketing) of Enterprise GP upon consummation of the Holdings Merger. He joined Enterprise in July 2007 as Senior Vice President of EPGP to develop and lead the Partnership’s Natural Gas Services and Marketing group. In July 2008, he also assumed responsibility for Enterprise’s non-regulated and intrastate natural gas pipeline and storage businesses. From 1995 to July 2007, he served in various executive positions at ONEOK, Inc. and ONEOK Partners L.P. He led ONEOK Energy Services from 1995 to 2005, and held senior executive positions at ONEOK from 2005 to 2007.

Thomas M. Zulim. Since July 2008, Mr. Zulim has served as a Senior Vice President of EPCO, and was elected Senior Vice President (Unregulated NGL Business) of Enterprise GP upon consummation of the Holdings Merger, with responsibility for Enterprise’s unregulated NGL business. Mr. Zulim previously served as a Senior Vice President of EPGP from July 2008 to November 2010. From March 2006 to July 2008, Mr. Zulim served as Senior Vice President, Human Resources, for both EPGP and EPCO, and served as Vice President, Human Resources, for both EPGP and EPCO from December 2004 to March 2006. He joined EPCO in 1999 as Director of Business Management for the NGL Fractionation business. Mr. Zulim came to EPCO from Shell Oil Company where, as an attorney, he practiced labor and employment law nationally for several years before joining Shell Midstream Enterprises in 1996 as Director of Business Development for its natural gas processing and NGL fractionation businesses. Mr. Zulim resumed practicing law with EPCO’s legal group in January 2002 until December 2004.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that the following persons should serve as a director of our general partner.

Five of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Ms. Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO’s businesses, including ownership and management of Enterprise’s businesses; for Dr.

Cunningham, over 45 years of refined products, chemicals and midstream businesses; for Mr. Bachmann, over 29 years of experience with our midstream assets, including legal, regulatory, contract and merger and acquisitions and, for over the last ten years, as a member of Enterprise's executive management team; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise, including finance and accounting (certified public accountant) and more than seven years of management experience in the financial industry; and for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for the Enterprise's businesses.

Our six outside directors also have significant experience in our industry in a variety of capacities, as well as other qualifications, attributes and skills. These include: for Mr. McMahen, banking and finance; for Mr. Smith, banking and investments; for Mr. Andress, oil and gas exploration and production; for Mr. Barnett, legal, regulatory and management skills as a former managing partner of an international law firm; for Mr. Ross, executive management of oilfield services businesses; and for Mr. Rampacek, executive management of petroleum products refining, transportation and supply businesses.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, Enterprise GP, directors and executive officers of Enterprise GP, and certain other officers, and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2010.

Item 11. Executive Compensation.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our partnership. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO pursuant to the ASA. Pursuant to the ASA, we reimburse EPCO for 100% of EPCO's compensation costs related to our partnership. For additional information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

137

Table of Contents

Summary Compensation Table

The following table presents total compensation amounts, paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2010, 2009 and 2008 for the CEO, the CFO, and the three other most highly compensated executive officers of our general partner as of December 31, 2010. Collectively, these individuals were our "named executive officers" for 2010. The compensation amounts presented below include amounts allocated to Holdings prior to the Holdings Merger (see Item 1 of this annual report for a description of the Holdings Merger).

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
Michael A. Creel	2010	$ 607,187	$ 1,046,875	$ 2,091,096	$ 208,905	$ 388,681	$ 4,342,744
(President and CEO)	2009	580,000	1,280,000	2,616,695	718,920	216,630	5,412,245
	2008	563,200	552,000	3,668,620	171,360	200,241	5,155,421
W. Randall Fowler	2010	275,625	262,500	822,885	87,044	166,070	1,614,124
(Executive Vice President and CFO)	2009	206,719	354,375	973,475	242,422	80,271	1,857,262
	2008	190,781	131,250	1,377,456	53,550	62,646	1,815,683
A. James Teague	2010	650,000	650,000	1,710,310	174,087	372,446	3,556,843
(Executive Vice President and	2009	650,000	950,000	2,445,585	665,400	233,747	4,944,732
Chief Operating Officer)	2008	558,333	500,000	3,627,701	142,800	176,651	5,005,485
William Ordemann	2010	406,300	250,000	1,090,726	174,087	283,173	2,204,286
(Executive Vice President)	2009	395,200	310,000	1,643,242	565,950	220,470	3,134,862
	2008	391,400	265,000	1,779,805	142,800	157,884	2,736,889
Mark. A Hurley (5)	2010	290,341	375,000	800,000	89,812	56,924	1,612,077
(Senior Vice President)							

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards for 2010 were paid in February 2011).
(2) Amounts represent our estimated share of the aggregate grant date fair value of restricted common unit awards and limited partnership interests in the Employee Partnerships granted during each year presented. For information about assumptions made in the valuation of these awards and limited partner interests, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which information is incorporated by reference into this Item 11.

(3) Amounts represent our estimated share of the aggregate grant date fair value of unit option awards granted during each year presented. For information about assumptions made in the valuation of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which information is incorporated by reference into this Item 11.
(4) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.
(5) Mr. Hurley's cash bonus amount includes sign-on bonus payments totaling $200,000. Mr. Hurley joined us in March 2010.

Each of the named executive officers continues to perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers are allocated to us and our affiliates based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

Table of Contents

The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses, which includes Duncan Energy Partners, and those of our other affiliates for each of the years presented. The percentages listed for Enterprise Products Partners have been retrospectively adjusted to include the amount of time each officer devoted to Holdings prior to the Holdings Merger.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and other affiliates	Total Time Allocated
Michael A. Creel (CEO)	2010	84%	16%	100%
	2009	80%	20%	100%
	2008	80%	20%	100%
W. Randall Fowler (CFO)	2010	53%	47%	100%
	2009	50%	50%	100%
	2008	50%	50%	100%
A. James Teague	2010	100%	--	100%
	2009	100%	--	100%
	2008	100%	--	100%
William Ordemann	2010	100%	--	100%
	2009	100%	--	100%
	2008	100%	--	100%
Mark A. Hurley	2010	100%	--	100%

Compensation Discussion and Analysis

With respect to our named executive officers, compensation paid or awarded by us for the last three fiscal years reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. The EPCO Trustees control EPCO and provide recommendations with respect to the compensation of our CEO. As discussed further below, the ACG Committee of our general partner was given ultimate decision-making authority with respect to 2010 compensation to be paid to our CEO, and our CEO was given ultimate decision-making authority with respect to 2010 compensation to be paid to our other named executive officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Board or the ACG Committee of our general partner, except in the case of compensation paid to our CEO (as described below). Neither EPCO nor our general partner has a separate compensation committee; however, equity awards under EPCO's long-term incentive plans are approved by the ACG Committee of the respective issuer.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO's compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of

EPCO and its affiliates at both the partnership and individual levels. With respect to the three years ended December 31, 2010, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

Table of Contents

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2010, the elements of compensation for the named executive officers consisted of the following:

- Annual cash base salary;
- Discretionary annual cash bonus awards;
- Awards under long-term incentive arrangements; and
- Other compensation, including very limited perquisites.

In order to assist our CEO, EPCO and the ACG Committee of our general partner with compensation decisions, the senior vice president of Human Resources for EPCO formulates preliminary compensation recommendations for each of the named executive officers, including our CEO. With respect to compensation to be paid to our CEO, the EPCO Trustees consider the preliminary recommendation and make revisions, if appropriate. Afterwards, the EPCO Trustees and the senior vice president of Human Resources for EPCO present the revised CEO compensation recommendation to the members of the ACG Committee. The ACG Committee considers the recommendation and then makes a final determination regarding compensation of our CEO. In making their final determination, the ACG Committee may discuss the recommendations with the senior vice president of Human Resources, request to discuss the recommendations with EPCO's compensation consultant, and/or retain its own compensation consultant.

With respect to compensation to be paid to named executive officers other than our CEO, the CEO considers the preliminary recommendation of EPCO's senior vice president of Human Resources and makes revisions, if appropriate. The CEO makes a final determination regarding compensation of each named executive officer (other than the CEO himself).

In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third-party compensation consultant. In 2009, EPCO engaged Hewitt Associates, LLC (currently Meridian Compensation Partners, LLC, a spin-off from Hewitt in 2010, the "Consultant") to review executive compensation relative to our industry. The Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and external trends. Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers, for which our ACG Committee (in the case of our CEO's compensation) or our CEO (in the case of compensation to be paid to our other named executive officers) has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

The ACG Committee, our CEO and EPCO do not use any formula or specific performance-based criteria for our named executive officers in determining compensation for services performed for us; rather, the ACG Committee or our CEO (as applicable) and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the ACG Committee or our CEO (as applicable) may take into account in making the case-by-case compensation determinations include total value of all elements of compensation and the appropriate balance of internal pay equity among executive officers. The ACG Committee, our CEO and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are discretionary and, as noted above, subject to the ultimate decision-making

Table of Contents

authority of the ACG Committee or the CEO (as applicable), except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe the absence of specific performance-based criteria associated with our cash compensation and equity awards, and the long-term nature of our equity awards, has the effect of discouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among the EPCO Trustees, our CEO and the senior vice president of Human Resources for EPCO, subject to final determination by the ACG Committee (in the case of our CEO's cash bonus awards) and our CEO (in the case of cash bonus awards to be paid to our other named executive officers). These cash bonus awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers perform services. It is EPCO's general policy to pay these awards in February of the following year.

The awards granted under EPCO's long-term incentive plans to our named executive officers were determined by consultation among the EPCO Trustees, our CEO and the senior vice president of Human Resources for EPCO, and were approved by the ACG Committee of the respective issuer.

EPCO expects to continue its policy of covering limited perquisites allocable to our named executive officers, including reimbursement of parking expenses. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2010.

In August 2010, the Employee Partnerships were liquidated with the consent of EPCO (in its capacity as the general partner of each Employee Partnership) and the Class A and Class B limited partners thereof, in accordance with the terms of each Employee Partnership's partnership agreement. Upon the liquidation of each Employee Partnership, the assets of such Employee Partnership were distributed to the Class A and B limited partners thereof. As a result, the Class B limited partners of each Employee Partnership, which included our named executive officers, received a liquidating distribution of partnership assets consisting of limited partner interests in either us or Holdings. See "Option Exercises and Units Vested" within this Item 11 for additional information.

In the fourth quarter of 2010, EPCO entered into retention agreements with Messrs. Creel, Fowler, Teague and Ordemann to reinforce and encourage the continued dedication of such officers to EPCO and us as a member of our senior management team and to assure that we and EPCO will have the services of the executives in the foreseeable future. Pursuant to the retention agreements, Messrs. Creel, Fowler, Teague and Ordemann will be entitled to a cash retention payment of $10 million, $5 million, $10 million and $2.5 million, respectively, less applicable withholding taxes (as applicable to each person, the "Retention Payment") following the completion of 48 months of continuous employment with EPCO from the effective date of each retention agreement (the "Retention Period"). We will receive an allocation of such costs based on the approximate amount of time each officer spends on our consolidated business activities. The effective date of the retention agreements for Mr. Creel, Mr. Fowler and Mr. Teague was December 1, 2010. The effective date of the retention agreement for Mr. Ordemann was October 1, 2010.

Notwithstanding the required Retention Period, if at any time between 24 months and 48 months after December 1, 2010 (the period of continuous employment from December 1, 2010 until such time being referred to as the "Performance Period"), Mr. Teague designates a candidate to serve as Chief

Table of Contents

Operating Officer of Enterprise GP and such candidate is determined by the ACG Committee of the Board of Directors of Enterprise GP to be satisfactory and is hired by EPCO, then Mr. Teague will be entitled to a cash performance payment of the greater of (a) $6 million or (b) $10 million times (i) the number of months of Mr. Teague's Performance Period, divided by (ii) 48 (the "Performance Payment"). Pursuant to his retention agreement, Mr. Teague is eligible to earn and receive either the Performance Payment or the Retention Payment, but not both.

Notwithstanding the Retention Period described above, each of Messrs. Creel, Fowler, Teague, and Ordemann will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in his retention agreement) in connection with his job elimination, a business reorganization or a sale of EPCO or us.

Any Retention Payment or Performance Payment (with respect to Mr. Teague) is in addition to any discretionary incentive compensation that EPCO or any of its affiliates may, in its sole discretion, grant or have in place from time to time.

Although the retention agreements are entered into with EPCO, all or a portion of the compensation related to these agreements may be allocated to us in accordance with the ASA by and among EPCO, the partnership, Duncan Energy Partners and the other parties thereto.

We believe that each of the base salary, cash bonus awards, long-term incentive awards and retention agreements, as applicable, fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with the partnership's risk management policies.

Table of Contents

Grants of Plan-Based Awards in Fiscal Year 2010

The following table presents information concerning each grant of a plan-based award made to a named executive officer in 2010 for which we will be allocated by EPCO our pro rata share under the ASA. The restricted common unit and unit option awards granted during 2010 were under EPCO's long-term incentive plans. See "Summary of Long-Term Incentive Arrangements Underlying 2010 Award Grants" within this discussion of compensation of directors and executive officers for additional information regarding the long-term incentive plans under which these awards were granted.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted common unit awards: (2)						
Michael A. Creel (CEO)	2/23/10	--	81,000	--	--	$ 2,091,096
W. Randall Fowler (CFO)	2/23/10	--	51,000	--	--	822,885
A. James Teague	2/23/10	--	53,000	--	--	1,710,310
William Ordemann	2/23/10	--	33,800	--	--	1,090,726
Mark A. Hurley	5/6/10	--	25,000	--	--	800,000
Unit option awards: (2)						
Michael A. Creel (CEO)	2/23/10	--	90,000	--	$ 32.27	208,095
W. Randall Fowler (CFO)	2/23/10	--	60,000	--	32.27	87,044
A. James Teague	2/23/10	--	60,000	--	32.27	174,087
William Ordemann	2/23/10	--	60,000	--	32.27	174,087
Mark A. Hurley	5/6/10	--	30,000	--	32.00	89,812

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated business activities during 2010. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will approximate these amounts over the vesting period.
(2) Awards granted to the named executive officers during 2010 were made under either the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") or the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan").

The grant date fair value amounts presented in the table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our fair value assumptions made in connection with equity-based compensation.

Table of Contents

Summary of Long-Term Incentive Arrangements Underlying 2010 Award Grants

The following information summarizes the principal types of awards granted to our named executive officers under EPCO's long-term incentive plans during 2010. These plans provide for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates.

Awards granted under the 1998 Plan may be in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Awards granted under the 2008 Plan may be in the form of unit options, restricted common units, phantom units, unit appreciation rights ("UARs") and DERs. As of December 31, 2010, no phantom unit awards, UARs or associated DERs have been granted under the EPCO plans to the named executive officers.

Restricted common unit awards. Restricted common unit awards allow recipients to acquire common units of Enterprise (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. For awards granted prior to 2010, the restrictions on such awards generally lapse four years from the date of grant. Beginning in 2010, new restricted common unit grants generally vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted common units is based on the market price per unit of the underlying security on the date of grant. For financial statement purposes, compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid by the respective issuer.

Unit option awards. Non-qualified incentive options to purchase a fixed number of common units of Enterprise may be granted to key employees of EPCO. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield on the underlying security, and expected price volatility of the underlying security. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of historical price volatility and distribution yield over a period equal to the expected life of the option.

Table of Contents

Equity Awards Outstanding at December 31, 2010

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2010. We expect to be allocated our pro rata share of the expense associated with such awards under the ASA. As a result, the gross amounts listed in the tables do not represent the amount of expense we expect to recognize in connection with these awards.

The following table presents information concerning each named executive officer's restricted common unit and options awards outstanding at December 31, 2010. The referenced units in the table below are common units of Enterprise.

		Option Awards				Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Exercisable (#)	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#) (2)	Market Value of Units That Have Not Vested ($) (3)
Restricted common unit awards:							
Michael A. Creel (CEO)	Various (1)	--	--	--	--	198,100	$ 8,242,941
W. Randall Fowler (CFO)	Various (1)	--	--	--	--	130,100	5,413,461
A. James Teague	Various (1)	--	--	--	--	145,000	6,033,450
William Ordemann	Various (1)	--	--	--	--	112,700	4,689,447
Mark A. Hurley	Various (1)	--	--	--	--	25,000	1,040,250
Unit option awards:							
Michael A. Creel (CEO):							
May 29, 2007 option grant	5/29/11	--	60,000	$ 30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	90,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	75,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	90,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	90,000	32.27	12/31/15	--	--
W. Randall Fowler (CFO):							
	5/29/11	--	45,000	30.96	12/31/12	--	--

May 29, 2007 option grant							
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	52,500	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
A. James Teague:							
May 29, 2007 option grant	5/29/11	--	60,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
William Ordemann:							
May 29, 2007 option grant	5/29/11	--	30,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	45,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
Mark A. Hurley:							
May 6, 2010 option grant	5/6/14	--	30,000	32.00	12/31/15	--	--

(1) Of the 610,900 restricted common unit awards presented in the table, 90,800 vest in 2011, 124,300 vest in 2012, 177,000 vest in 2013 and 218,800 vest in 2014.
(2) Amounts represent the total number of restricted common unit awards granted to each named executive officer.
(3) Amounts derived by multiplying the total number of restricted common unit awards outstanding for each named executive officer by the closing price of our common units at December 31, 2010 of $41.61 per unit.

Table of Contents

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted common units (in each case, involving the common units of Enterprise) to our named executive officers during the year ended December 31, 2010 for which we were historically responsible for a portion of the related expense of such awards.

Name	Option Awards Number of Units Acquired on Exercise (#)	Option Awards Gross Value Realized on Exercise ($) (1)	Unit Awards Number of Units Acquired on Vesting (#)	Unit Awards Gross Value Realized on Vesting ($) (2,3)
Michael A. Creel (CEO):				
Option awards	75,000	$910,800		
Restricted common unit awards			12,000	$427,300
Employee Partnerships: (3)				
Common units of Enterprise			97,484	3,674,159
Units of Holdings			242,271	12,307,475
W. Randall Fowler (CFO):				
Option awards	65,000	798,000		
Restricted common unit awards			12,000	427,320
Employee Partnerships: (3)				
Common units of Enterprise			79,776	3,006,747
Units of Holdings			179,116	9,099,173
A. James Teague:				
Option awards	75,000	910,800		
Restricted common unit awards			12,000	427,320
Employee Partnerships: (3)				
Common units of Enterprise			83,318	3,140,244
Units of Holdings			170,510	8,661,984
William Ordemann:				
Option awards	80,000	934,750		
Restricted common unit awards			7,200	256,392
Employee Partnerships: (3)				
Common units of Enterprise			14,165	533,877
Units of Holdings			112,721	5,726,277

(1) Amount determined by multiplying the number of units acquired on exercise of the options by the difference between the closing price of Enterprise's common units on the date of exercise and the exercise price.
(2) Amount determined for restricted common unit awards by multiplying the number of restricted common unit awards that vested during 2010 by the closing price of Enterprise's common units on the date of vesting.
(3) EPCO granted limited partnership interests in the Employee Partnerships to its key employees who perform services on behalf of us, EPCO and other affiliated companies. These partnerships were liquidated in August 2010 and the assets of each partnership (consisting of either common units of Enterprise's or units of Holdings or a combination of both) were distributed to their partners, which included certain of our named executive officers. The gross value realized on vesting (i.e., liquidation in this case) was determined by multiplying the number of limited partner units received by the named executive officer by the closing price of Enterprise's or Holdings' limited partner units on the date of liquidation.

Table of Contents

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and the ACG Committee of our general partner.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2010.

Submitted by: Randa Duncan Williams
Dr. Ralph S. Cunningham
Richard H. Bachmann
Thurmon M. Andress
Charles E. McMahen
Edwin W. Smith
Michael A. Creel
A. James Teague
E. William Barnett
Charles M. Rampacek
Rex C. Ross

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during 2010. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and the ACG Committee of our general partner.

Table of Contents

Director Compensation

Neither we nor our general partner provide any additional compensation to employees of EPCO who serve as directors of our general partner. The following table presents information regarding compensation paid to the independent directors of our general partner, including amounts paid to Messrs. Andress, McMahen and Smith in connection with their service as independent directors of the general partner of Holdings prior to the Holdings Merger, during the year ended December 31, 2010. All of the independent directors listed below became independent directors of our general partner following the Holdings Merger.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Thurmon M. Andress	$114,000	$40,000	$ 819,000	$973,000
E. William Barnett (1)	162,000	75,000	819,000	1,056,000
Charles E. McMahen (2)	129,000	40,000	--	169,000
Charles M. Rampacek	145,500	75,000	819,000	1,039,500
Rex C. Ross	148,500	75,000	819,000	1,042,500
Edwin E. Smith	100,500	40,000	819,000	959,500

(1) Mr. Barnett served as chairman of our ACG Committee from January 1, 2010 to November 22, 2010.
(2) Mr. McMahen served as chairman of the ACG Committee of Holdings from January 1, 2010 to November 22, 2010. On November 22, 2010, Mr. McMahen was elected chairman of our ACG Committee.

For the year ended December 31, 2010, the independent directors listed in the preceding table were compensated as follows:

§ Each independent director received a $75,000 annual cash retainer;

§ If the individual served as chairman of a committee of the Board, then he received an additional $15,000 in cash annually;

§ Each independent director received a meeting fee of $1,500 in cash for each meeting of the Board attended. In addition, each independent director received a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee;

§ Prior to the Holdings Merger, each independent director of the general partner of Holdings (i.e., Messrs. Andress, McMahen and Smith) received an annual grant of Holdings' limited partner units having a fair market value, based on the closing price of such securities on the trading day immediately preceding the date of grant, of $40,000. Likewise, each independent director of our general partner (Messrs. Barnett, Rampacek and Ross) received an annual grant of our common units having a fair market value, based on the closing price of such securities on the trading day immediately preceding the date of grant, of $75,000; and

§ Each independent director (with the exception of Mr. McMahen) received a one-time payment of $819,000 in recognition of their extraordinary efforts during 2010. A one-time payment in the amount of $819,000 was made to Mr. McMahen in January 2011. The payments made to Messrs. Smith and Andress in December 2010 and Mr. McMahen in January 2011 were also partially attributable to their surrender of certain UARs issued to them under a long-term incentive plan of Holdings. These UARs were assumed by us in connection with the Holdings Merger and subsequently cancelled when each director surrendered the awards.

For 2011, the independent directors of our general partner will be compensated as follows: (i) each will receive a $75,000 annual cash retainer; (ii) if the individual serves as chairman of a committee of the Board, then he will receive an additional $15,000 in cash annually; (iii) each will receive a meeting fee

Table of Contents

of $1,500 in cash for each meeting of the Board attended; (iv) each will receive a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee; and (v) each will receive an annual grant of our common units having a fair market value, based on the closing price of such securities on the trading day immediately preceding the date of grant, of $75,000.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 1, 2011, regarding each person known by our general partner to beneficially own more than 5% of Enterprise's limited partner units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams	333,762,482 (1)	39.6%
	1100 Louisiana Street, 10th Floor		
	Houston, Texas 77002		
Class B units	Randa Duncan Williams	4,520,431	100%
	1100 Louisiana Street, 10th Floor		
	Houston, Texas 77002		

(1) For a detailed listing of ownership amounts that comprise Ms. Williams' total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

Security Ownership of Management

The following table sets forth certain information regarding the beneficial ownership of our common units and the common units of Duncan Energy Partners as of February 1, 2011 by (i) our named executive officers; (ii) the current directors of our general partner; and (iii) the current directors and executive officers (including named executive officers) of our general partner as a group. As of February 1, 2011, Enterprise owned 100% of the member interests of EPO, which directly owns 100% of the member interests of the general partner of Duncan Energy Partners and indirectly owns 58.5% of the common units of Duncan Energy Partners through a subsidiary.

All beneficial ownership information has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise. The beneficial ownership amounts of certain individuals include options to acquire common units of Enterprise that are exercisable within 60 days of the filing date of this annual report.

Ms. Williams is a voting trustee of each of the DD LLC Voting Trust and the EPCO Voting Trust, an independent co-executor of the estate of Dan L. Duncan and a beneficiary of the estate. Ms. Williams is currently Chairman and a Director of EPCO. Ms. Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees, the DD LLC Trustees and Mr. Duncan's estate except to the extent of her voting and dispositive interests in such units.

Table of Contents

Name of Beneficial Owner	Duncan Energy Partners L.P. Common Units Amount and Nature Of Beneficial Ownership	Duncan Energy Partners L.P. Common Units Percent of Class	Enterprise Products Partners L.P. Common Units Amount and Nature Of Beneficial Ownership	Enterprise Products Partners L.P. Common Units Percent of Class
Randa Duncan Williams:				
Units controlled by Dan Duncan LLC Voting Trust:				
Through DFI GP Holdings L.P.	--	--	40,844,206	4.8 %
Through Enterprise Products Holdings LLC	--	--	20,881	*
Through EPO	33,783,587	58.5 %	--	--
Units controlled by EPCO Voting Trust:				
Through EPCO	--	--	523,306	*
Through EPCO Investments, LLC	--	--	15,241,517	1.8 %
Through Duncan Family Interests, Inc.	--	--	257,909,910	30.6 %
Through EPCO Holdings, Inc.	99,453	*	7,739,181	*
Units controlled by estate of Dan L. Duncan (1)	485,600	*	9,620,981	1.1 %
Units controlled by Alkek and Williams, Ltd.	50,000	*	112,500	*
Units controlled by family trusts (2)	--	--	1,750,000	*
Units owned personally (3)	6,500	*	--	--
Total for Randa Duncan Williams	34,425,140	59.6 %	333,762,482	39.6 %
Michael A. Creel (CEO) (4)	7,500	*	683,543	*
W. Randall Fowler (CFO) (4)	2,000	*	517,513	*
A. James Teague (4,5)	6,000	*	689,069	*
William Ordemann (4)	3,810	*	354,891	*
Mark A. Hurley (4)	--	*	25,000	*
Thurmon M. Andress (6)	--	*	22,995	*
E. William Barnett	--	*	17,974	*
Charles E. McMahen	20,000	*	16,746	*
Charles M. Rampacek	--	*	11,935	*
Rex C. Ross (7)	--	*	61,367	*
Edwin E. Smith	34,000	*	150,899	*
All current directors and executive officers of our general partner, as a group (22 individuals in total)	34,558,519	59.8 %	338,699,700	40.1 %

* Represents a beneficial ownership of less than 1% of class

(1) The number of Duncan Energy Partners' and Enterprise's common units presented for the estate of Mr. Duncan includes common units of each registrant held of record by DD Securities LLC.

(2) The number of Enterprise's common units presented for Ms. Williams includes 1,312,500 common units held by family trusts for which she is the trustee but has disclaimed beneficial ownership.

(3) The number of Duncan Energy Partners' common units presented for Ms. Williams includes 4,500 common units held of record by her spouse and 2,000 common units held of record jointly with her spouse.

(4) These individuals are named executive officers.

(5) The number of Enterprise common units presented for Mr. Teague includes (i) 186,784 common units held by an immediate family member and (ii) 1,000 common units held by a family trust.

(6) The number of Enterprise common units presented for Mr. Andress includes 9,300 common units held by a family partnership.
(7) The number of Enterprise common units presented for Mr. Ross includes 7,000 common units held by a family trust.

Essentially all of the ownership interests in Enterprise that are owned or controlled by Duncan Family Interests, Inc. and DFI GP Holdings, L.P are pledged as security under the credit facility of an EPCO affiliate. This credit facility contains customary and other events of default relating to EPCO and certain of its affiliates, including Enterprise. In the event of a default under this credit facility, a change in control of Enterprise could occur, including a change in control of its general partner.

Table of Contents

Equity Ownership Guidelines

On December 31, 2009, the ACG Committee of the Board recommended to the Board, and effective on January 1, 2010, the Board adopted and approved, new equity ownership guidelines for our general partner's directors and executive officers in order to further align their interests and actions with the interests of our general partner, us and our unitholders. Under the new guidelines:

§ each non-management director of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board paid for the most recently completed calendar year; and

§ each executive officer of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year; provided, however, that the value of any common units of Duncan Energy Partners owned by an executive officer of our general partner who is also an executive officer of the general partner of Duncan Energy Partners, shall be counted toward the equity ownership requirements set forth above.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2010 regarding the long-term incentive plans of EPCO under which our common units are authorized for issuance. For additional information regarding our equity-based compensation, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options (a)	Weighted-Average Exercise Price of Outstanding Common Unit Options (b)	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by unitholders:			
1998 Plan (1)	745,000	$ 30.17	1,302,085
2006 Plan (2)	118,420	$ 26.11	n/a
2008 Plan (3)	2,890,000	$ 27.62	5,945,967
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	3,753,420	$ 28.08	7,248,052

(1) Of the 745,000 unit options outstanding at December 31, 2010, 685,000 are exercisable in 2011 and an additional 30,000 are exercisable in each of 2013 and 2014.
(2) Of the 118,420 unit options outstanding at December 31, 2010, 27,280 are exercisable in 2011 and an additional 31,000 and 60,140 are exercisable in 2012 and 2013, respectively. No additional awards are expected to be issued under the 2006 Plan.
(3) Of the 2,890,000 unit options outstanding at December 31, 2010, 705,000 are exercisable in 2012 and an additional 1,430,000 and 755,000 are exercisable in 2013 and 2014, respectively.

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and distribution equivalent rights. Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan.

Table of Contents

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, unit appreciation rights and distribution equivalent rights. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Certain Relationships and Related Transactions

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report and incorporated by reference into this Item 13.

Review and Approval of Transactions with Related Parties

We consider transactions between us and our subsidiaries, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including other companies owned or controlled by the DD LLC Trustees or the EPCO Trustees), on the other hand, to be related party transactions. As further described below, our Partnership Agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by our general partner or its ACG Committee. In addition, our ACG Committee Charter, our general partner's written internal review and approval policies and procedures (or management authorization policy) and the amended and restated ASA with EPCO govern specified related party transactions, as further described below.

In accordance with its charter, the ACG Committee reviews and approves related party transactions:

§ for which Board approval is required by our management authorization policy, as such policy may be amended from time to time;

§ where an officer or director of the general partner or any of our subsidiaries is a party, without regard to the size of the transaction;

§ when requested to do so by management or the Board; or

§ pursuant to our Partnership Agreement or the limited liability company agreement of the general partner, as such agreements may be amended from time to time.

As discussed in more detail in "Directors, Executive Officers and Corporate Governance —Partnership Management," "—Corporate Governance" and "—ACG Committee" within Item 10 of this annual report, at December 31, 2010, the ACG Committee was comprised of three directors: Rex C. Ross, Charles E. McMahen and E. William Barnett. During the year ended December 31, 2010, the ACG Committee reviewed and approved each of the following related party transactions:

§ the purchase of additional marine transportation assets from Arlen B. Cenac, Jr. and affiliates in April 2010 and August 2010;

§

agreements and transactions with Duncan Energy Partners in May 2010 and August 2010 related to the Haynesville Extension;

§ the Holdings Merger in September 2010; and

Table of Contents

§ the drop down of a truck transportation business from EPCO in September 2010.

Our management authorization policy currently requires Board approval for the following types of transactions to the extent such transactions have a value in excess of $100 million (thus triggering ACG Committee review under our ACG Committee Charter if such transaction is also a related party transaction):

§ asset purchase or sale transactions;

§ capital expenditures; and

§ purchase orders and operating and administrative expenses not governed by the ASA.

The ASA governs numerous day-to-day transactions between us, our general partner and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our reimbursement of costs, without markup or discount, for those services. The ASA was reviewed and recommended to the Board by our ACG Committee, and the Board approved it upon receiving such recommendation. For a summary of the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our general partner's officers and chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Business Opportunity Agreements

The ASA also addresses potential conflicts that may arise among Enterprise (including Enterprise GP), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise, Duncan Energy Partners and our respective general partners. With respect to potential conflicts regarding third-party business opportunities, the ASA provides, among other things, that:

§ If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, or to Enterprise (including Enterprise GP) or Duncan Energy Partners (including DEP GP), then Enterprise will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

§ general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

§ incentive distribution rights ("IDRs") and limited partner interests (or securities which have characteristics similar to IDRs or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

Enterprise will be presumed to want to acquire the equity securities until such time as Enterprise GP advises the EPCO Group and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100 million, the decision to decline the acquisition will be made by the CEO of Enterprise GP after consultation with and subject to the approval of the

ACG Committee of

Table of Contents

Enterprise GP. If the purchase price is reasonably likely to be less than $100 million, the CEO of Enterprise GP may make the determination to decline the acquisition without consulting the ACG Committee of Enterprise GP.

In its sole discretion, Enterprise may direct such acquisition opportunity to DEP GP for consideration; however, Enterprise is under no obligation to do so. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise abandons the acquisition opportunity (and DEP GP is either not granted the opportunity by Enterprise or declines such opportunity outright), then the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

§ If a business opportunity not involving "equity securities" (as defined above) is presented to the EPCO Group, or to Enterprise (including Enterprise GP), or Duncan Energy Partners (including DEP GP), Enterprise will have the first right to pursue such opportunity either for itself or, if desired by Enterprise in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise will pursue the business opportunity until such time as its general partner advises the EPCO Group and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with this type of business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the CEO of Enterprise GP after consultation with and subject to the approval of the ACG Committee of Enterprise GP. If the purchase price or cost is reasonably likely to be less than $100 million, the CEO of Enterprise GP may make the determination to decline the business opportunity without consulting Enterprise GP's ACG Committee.

In its sole discretion, Enterprise may direct such acquisition opportunity to DEP GP for consideration; however, Enterprise is under no obligation to do so. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise abandons the acquisition opportunity (and DEP GP is either not granted the opportunity by Enterprise or declines such opportunity outright), then the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

Partnership Agreement Standards for ACG Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by our general partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our general partner's ACG Committee ("Special Approval") or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);

§ any customary or accepted industry practices and any customary or historical dealings with a particular person;

§ any applicable generally accepted accounting or engineering practices or principles;

§ the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and

§ such additional factors as the ACG Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable to us, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under our partnership agreement.

The review and work performed by the ACG Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the ACG Committee's charge. Examples of functions the ACG Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

§ assessing the business rationale for the transaction;

§ reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;

§ assessing the effect of the transaction on our earnings and distributable cash flow per unit, and on our results of operations, financial condition, properties or prospects;

§ conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;

§ considering the relative advantages and disadvantages of the transactions to the parties;

§ engaging third-party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;

§ engaging legal advisors; and

§ evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in the partnership agreement requires the ACG Committee to consider the interests of any person other than the partnership. In the absence of bad faith by the ACG Committee or our general partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the ACG Committee or our general partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the ACG Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on

Table of Contents

behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Messrs. Ross, Rampacek, Andress, McMahen, Smith and Barnett have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to "Corporate Governance" and "ACG Committee" under Item 10 of this annual report.

Item 14. Principal Accountant Fees and Services.

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes fees we paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in millions):

	For Year Ended December 31,	
	2010	2009
Audit Fees (1)	$5.4	$6.2
Audit-Related Fees (2)	*	N/A
Tax Fees (3)	N/A	N/A
All Other Fees (4)	*	N/A

(1) Audit fees represent amounts billed for each of the years presented for (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements filed on Form 10-Q and (iii) those services normally provided by Deloitte & Touche in connection with our statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.
(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews and are not reported under the section labeled "Audit fees." No such services were rendered by Deloitte & Touche during the year ended December 31, 2009; however, we did engage Deloitte & Touche to perform certain assurance work related to the amendment of an environmental permit during the year ended December 31, 2010.
(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. No such services were rendered by Deloitte & Touche during the last two years.
(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the year ended December 31, 2009; however, we did engage Deloitte & Touche to perform certain software consulting services during the year ended December 31, 2010.
* Amount is negligible.

The ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine

Table of Contents

whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) The following documents are filed as a part of this annual report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this annual report for financial statements filed as part of this annual report.

(2) Financial Statement Schedules: All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits.

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to

	Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).

2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Certificate of Formation of EPE Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.5	Certificate of Amendment to Certificate of Formation of EPE Holdings, LLC, filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.6	Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC dated effective as of November 22, 2010 (incorporated by reference to Exhibit 3.3 to Form 8-K filed November 23, 2010).
3.7	First Amendment to Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated effective as of November 23, 2010 (changing name to Enterprise Products Holdings LLC) (incorporated by reference to Exhibit 3.4 to Form 8-K filed November 23, 2010).
3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Form S-1/A Registration Statement, Reg. No. 333-52537, filed July 21, 1998).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).

4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

Table of Contents

4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 6, 2004).
4.8	Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 6, 2004).
4.9	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.10	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.11	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.12	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.13	Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.14	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.15	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.16	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.17	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).

Table of Contents

4.18	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.19	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.20	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.21	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.22	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.23	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.24	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.25	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.26	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.27	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.28	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.29	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).

Table of Contents

4.34	Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.36	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.37	Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.38	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.39	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.40	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.41	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.42	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.43	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.44	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.48	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.49	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.50	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.51	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.52	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).

Table of Contents

4.53	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.54	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.55	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.56	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.57	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.58	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.59	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.60	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.61	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.62	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.63	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.64	Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.65	

Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).

Table of Contents

4.66	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.67	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.68	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.69	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.70	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.71	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
4.72	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.73	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.74	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
10.1***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.2***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before May 7, 2008 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed November 9, 2007).
10.3***	

	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued on or after May 7, 2008 but before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed May 12, 2008).
10.4***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed August 9, 2010).

Table of Contents

10.5***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed August 9, 2010).
10.6***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed August 9, 2010).
10.7***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed November 9, 2007).
10.8***	Amendment to Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed August 9, 2010).
10.9***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 10-Q filed August 9, 2010).
10.10***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed February 26, 2010).
10.11***	Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (February 23, 2010) (incorporated by reference to Exhibit 10.7 to Form 8-K filed February 26, 2010).
10.12***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 4.3 to Form S-8 (Commission File No. 333-150680) filed May 6, 2008).
10.13***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.9 to Form 10-Q filed August 9, 2010).
10.14***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued after February 23, 2010 and before August 5, 2010 (incorporated by reference to Exhibit 10.10 to Form 10-Q filed August 9, 2010).
10.15***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 10-Q filed August 9, 2010).
10.16***	Amendment to Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.12 to Form 10-Q filed August 9, 2010).
10.17***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 9, 2010).
10.18***	Form of Non-Employee Director Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 8-K filed February 26, 2010).
10.19***	2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (Amended and Restated February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.20***	Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.14 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010).
10.21***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.15 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010).
10.22***	Form of Non-Employee Director Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Duncan

	Energy Partners L.P. on February 26, 2010).
10.23***	Agreement of Limited Partnership of EPE Unit L.P. dated August 23, 2005 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on September 1, 2005).
10.24***	First Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).

Table of Contents

10.25***	Second Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.26***	Third Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.27***	Agreement of Limited Partnership of EPE Unit II, L.P. dated December 5, 2006 (incorporated by reference to Exhibit 10.13 to Form 10-K filed February 28, 2007).
10.28***	First Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.29***	Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.30***	Third Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.31***	Agreement of Limited Partnership of EPE Unit III, L.P. dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.32***	First Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.33***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.34***	Third Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.35***	Agreement of Limited Partnership of Enterprise Unit L.P. dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2008).
10.36***	First Amendment to Agreement of Limited Partnership of Enterprise Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.37***	Agreement of Limited Partnership of EPCO Unit L.P. dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to Form 8-K filed November 18, 2008).
10.38***	First Amendment to Agreement of Limited Partnership of EPCO Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.39	Fifth Amended and Restated Administrative Services Agreement, dated as of January 30, 2009, by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating LLC, Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, LLC, TEPPCO Midstream Companies, LLC, TCTM, L.P. and TEPPCO GP, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 5, 2009).
10.40	Amended and Restated Omnibus Agreement dated as of December 8, 2008 among Enterprise Products Operating LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC, Enterprise Holding III, L.L.C.,

	Enterprise Texas Pipeline, LLC, Enterprise Intrastate, L.P. and Enterprise GC, LP (incorporated by reference to Exhibit 10.6 of Form 8-K filed by Duncan Energy Partners L.P. filed December 8, 2008).
10.41	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 5, 2007).

Table of Contents

10.42	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed by Duncan Energy Partners L.P. on January 3, 2008).
10.43	Amendment No. 2 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008).
10.44	Third Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 8, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).
10.45	Fourth Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated June 15, 2009 (incorporated by reference to Exhibit 3.1 of Form 8-K filed by Duncan Energy Partners L.P. on June 15, 2009).
10.46	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed July 1, 2005).
10.47	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 20, 2007).
10.48	First Amendment to Amended and Restated Revolving Credit Agreement, dated as of October 22, 2010, among Enterprise Products Operating LLC, as Borrower, Wells Fargo Bank, National Association, successor-by-merger to Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 26, 2010).
10.49	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 20, 2007).
10.50	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008).
10.51	Third Amended and Restated Agreement of Limited Partnership of Enterprise GC, L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.3 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).
10.52	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Intrastate L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.4 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).
10.53	Amended and Restated Company Agreement of Enterprise Texas Pipeline LLC dated December 8, 2008 (incorporated by reference to Exhibit 10.5 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).
10.54	Second Amended and Restated Limited Liability Company Agreement of Acadian Gas, LLC dated June 1, 2010 (incorporated by reference to Exhibit 10.01 of Form 8-K filed by Duncan Energy Partners L.P. on June 3, 2010).
10.55	Support Agreement, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise GP Holdings L.P., DD Securities LLC, DFI GP Holdings, L.P., Duncan Family Interests Inc., Duncan Family 2000 Trust and Dan L. Duncan (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 29, 2009).
10.56	Memorandum of Understanding, dated June 28, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 29, 2009).

10.57	Stipulation and Agreement of Compromise, Settlement and Release, dated August 5, 2009 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).

10.58	Common Unit Purchase Agreement, dated September 3, 2009, by and between Enterprise Products Partners L.P. and EPCO Holdings, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 4, 2009).
10.59	Loan Agreement, dated June 1, 2010, between Enterprise Products Operating LLC, as lender, and Duncan Energy Partners L.P., as borrower (incorporated by reference to Exhibit 10.02 to Form 8-K filed by Duncan Energy Partners L.P. on June 3, 2010).
10.60	First Amendment to Loan Agreement, dated August 20, 2010, between Enterprise Products Operating LLC, as lender, and Duncan Energy Partners L.P., as borrower (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on August 23, 2010).
10.61	Support Agreement, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., DD Securities LLC, DFI GP Holdings, L.P., EPCO Holdings, Inc., Duncan Family Interests, Inc., Dan Duncan LLC and DFI Delaware Holdings L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 7, 2010).
10.62	Revolving Credit and Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., as borrower, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB NOR Bank ASA and the Royal Bank of Scotland plc, as Co-Syndication Agents, and Scotia Capital, Barclays Bank plc and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Duncan Energy Partners L.P. on October 26, 2010).
10.63	Distribution Waiver Agreement, dated as of November 22, 2010, by and among Enterprise Products Partners L.P., EPCO Holdings, Inc. and the EPD Unitholder named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 23, 2010).
10.64***	Retention Agreement between William Ordemann and Enterprise Products Company dated effective October 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 14, 2010).
10.65***	Retention Agreement between Mr. Michael A. Creel and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed December 10, 2010).
10.66***	Retention Agreement between Mr. W. Randall Fowler and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed December 10, 2010).
10.67***	Retention Agreement between Mr. A. James Teague and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.3 to Form 8-K filed December 10, 2010).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2010, 2009, 2008, 2007 and 2006.
21.1#	List of subsidiaries as of February 1, 2011.
23.1#	Consent of Deloitte & Touche LLP.
23.2#	Consent of Grant Thornton LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2010 Annual Report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the December 31, 2010 Annual Report on Form 10-K.
32.1#	Section 1350 certification of Michael A. Creel for the December 31, 2010 Annual Report on Form 10-K.
32.2#	Section 1350 certification of W. Randall Fowler for the December 31, 2010 Annual Report on Form 10-K.
99.1#	Consolidated balance sheets of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2010 and 2009 and related consolidated statements of operations, comprehensive income, partners' capital, and cash flows for the years ended December 31, 2010, 2009 and 2008.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document

101.SCH# XBRL Schema Document

167

Table of Contents

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, Duncan Energy Partners L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-33266, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 1, 2011.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By:	Enterprise Products Holdings LLC, as General Partner
By:	/s/ Michael J. Knesek
Name:	Michael J. Knesek
Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

Table of Contents

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2011.

Signature	Title (Position with Enterprise Products Holdings LLC)
/s/ Dr. Ralph S. Cunningham	Director and Chairman
Dr. Ralph S. Cunningham	
/s/ Michael A. Creel	Director, President and Chief Executive Officer
Michael A. Creel	
/s/ W. Randall Fowler	Executive Vice President and Chief Financial Officer
W. Randall Fowler	
/s/ A. James Teague	Director, Executive Vice President and Chief Operating Officer
A. James Teague	
/s/ Richard H. Bachmann	Director
Richard H. Bachmann	
/s/ Randa Duncan Williams	Director
Randa Duncan Williams	
/s/ Thurmon M. Andress	Director
Thurmon M. Andress	
/s/ E. William Barnett	Director
E. William Barnett	
/s/ Edwin E. Smith	Director
Edwin E. Smith	
/s/ Charles E. McMahen	Director
Charles E. McMahen	
/s/ Rex C. Ross	Director
Rex C. Ross	
/s/ Charles M. Rampacek	Director
Charles M. Rampacek	
/s/ Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer
Michael J. Knesek	

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. We did not audit the financial statements of Energy Transfer Equity L.P., an investment of the Company, which is accounted for by the use of the equity method for the years ended December 31, 2009 and 2008. The Company's equity in Energy Transfer Equity L.P.'s net income of $77.7 million and $65.6 million (with both amounts prior to the Company's excess cost amortization – see Note 9) for the years ended December 31, 2009 and 2008, respectively, is included in the accompanying consolidated financial statements. Energy Transfer Equity L.P.'s financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Energy Transfer Equity L.P. for the years ended December 31, 2009 and 2008, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

The consolidated financial statements give effect to the merger of Enterprise GP Holdings L.P. with the Company on November 22, 2010, which has been accounted for as an equity transaction as described in Note 1.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$65.5	$55.3
Restricted cash	98.7	63.6
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $18.4 at December 31, 2010 and $16.8 at December 31, 2009	3,800.1	3,099.0
Accounts receivable – related parties	36.8	38.4
Inventories	1,134.0	711.9
Prepaid and other current assets	372.0	281.4
Total current assets	5,507.1	4,249.6
Property, plant and equipment, net	19,332.9	17,689.2
Investments in unconsolidated affiliates	2,293.1	2,416.2
Intangible assets, net of accumulated amortization of $932.3 at December 31, 2010 and $795.0 at December 31, 2009	1,841.7	1,064.8
Goodwill	2,107.7	2,018.3
Other assets	278.3	248.2
Total assets	$31,360.8	$27,686.3
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt	$282.3	$--
Accounts payable – trade	542.0	410.6
Accounts payable – related parties	133.1	70.8
Accrued product payables	4,164.8	3,393.0
Accrued interest	252.9	231.7
Other current liabilities	505.1	447.8
Total current liabilities	5,880.2	4,553.9
Long-term debt: (see Note 12)	13,281.2	12,427.9
Deferred tax liabilities	78.0	71.7
Other long-term liabilities	220.6	159.7
Commitments and contingencies		
Equity: (see Note 13)		
Partners' equity:		
Limited partners:		
Common units (843,681,572 units outstanding at December 31, 2010 and 208,787,460 Holdings Units outstanding at December 31, 2009)	11,288.2	1,972.4
Class B units (4,520,431 units outstanding at December 31, 2010)	118.5	--
General partner	--	**
Accumulated other comprehensive loss	(32.5)	(33.3)
Total partners' equity	11,374.2	1,939.1
Noncontrolling interest	526.6	8,534.0
Total equity	11,900.8	10,473.1
Total liabilities and equity	$31,360.8	$27,686.3

See Notes to Consolidated Financial Statements.
** Amount is negligible.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For Year Ended December 31,		
	2010	2009	2008
Revenues:			
Third parties	$33,040.9	$24,911.9	$34,454.2
Related parties	698.4	599.0	1,015.4
Total revenues (see Note 14)	33,739.3	25,510.9	35,469.6
Costs and expenses:			
Operating costs and expenses:			
Third parties	30,084.1	22,547.6	32,861.9
Related parties	1,365.2	1,018.2	757.0
Total operating costs and expenses	31,449.3	23,565.8	33,618.9
General and administrative costs:			
Third parties	82.9	85.6	49.8
Related parties	121.9	97.2	95.0
Total general and administrative costs	204.8	182.8	144.8
Total costs and expenses (see Note 14)	31,654.1	23,748.6	33,763.7
Equity in income of unconsolidated affiliates	62.0	92.3	66.2
Operating income	2,147.2	1,854.6	1,772.1
Other income (expense):			
Interest expense	(741.9)	(687.3)	(608.3)
Interest income	1.8	2.3	7.4
Other, net	2.7	(4.0)	4.9
Total other expense, net	(737.4)	(689.0)	(596.0)
Income before provision for income taxes	1,409.8	1,165.6	1,176.1
Provision for income taxes	(26.1)	(25.3)	(31.0)
Net income	1,383.7	1,140.3	1,145.1
Net income attributable to noncontrolling interest (see Note 13)	(1,062.9)	(936.2)	(981.1)
Net income attributable to partners	$320.8	$204.1	$164.0
Allocation of net income attributable to partners:			
Limited partners	$320.8	$204.1	$164.0
General partner	$**	$**	$**
Earnings per unit: (see Note 17)			
Basic earnings per unit	$1.17	$0.99	$0.89
Diluted earnings per unit	$1.15	$0.99	$0.89

See Notes to Consolidated Financial Statements.
** Amount is negligible.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For Year Ended December 31, 2010	2009	2008
Net income	$1,383.7	$1,140.3	$1,145.1
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instrument losses during period	(76.3)	(179.6)	(170.2)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	44.0	294.2	96.3
Interest rate derivative instrument gains (losses) during period	(0.1)	12.5	(73.0)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	25.6	26.4	5.5
Foreign currency derivative instrument gains (losses) during period	(0.1)	(10.2)	9.3
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	(0.3)	--	--
Total cash flow hedges	(7.2)	143.3	(132.1)
Foreign currency translation adjustment	0.9	2.1	(2.5)
Change in funded status of pension and postretirement plans, net of tax	0.4	--	(1.3)
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	10.2	2.5	(9.9)
Total other comprehensive income (loss)	4.3	147.9	(145.8)
Comprehensive income	1,388.0	1,288.2	999.3
Comprehensive income attributable to noncontrolling interest	(1,065.1)	(1,064.2)	(866.1)
Comprehensive income attributable to partners	$322.9	$224.0	$133.2

See Notes to Consolidated Financial Statements.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For Year Ended December 31, 2010	2009	2008
Operating activities:			
Net income	$1,383.7	$1,140.3	$1,145.1
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	985.1	836.8	740.1
Non-cash asset impairment charges	8.4	33.5	--
Equity in income of unconsolidated affiliates	(62.0)	(92.3)	(66.2)
Distributions received from unconsolidated affiliates	191.9	169.3	157.2
Operating lease expenses paid by EPCO	0.7	0.7	2.0
Gains from asset sales and related transactions	(46.7)	--	(4.0)
Loss on forfeiture of investment in Texas Offshore Port System	--	68.4	--
Loss on early extinguishment of debt	--	--	1.6
Deferred income tax expense	7.9	4.5	6.2
Changes in fair market value of derivative instruments	21.6	(0.9)	(0.9)
Effect of pension settlement recognition	(0.2)	(0.1)	(0.1)
Net effect of changes in operating accounts (see Note 20)	(190.4)	250.1	(414.6)
Net cash flows provided by operating activities	2,300.0	2,410.3	1,566.4
Investing activities:			
Capital expenditures	(2,040.8)	(1,584.3)	(2,539.6)
Contributions in aid of construction costs	38.7	17.8	27.2
Decrease (increase) in restricted cash	(35.0)	140.2	(132.8)
Cash used for business combinations (see Note 10)	(1,313.9)	(107.3)	(553.5)
Investments in unconsolidated affiliates	(8.0)	(19.6)	(64.7)
Proceeds from asset sales and related transactions	105.9	3.6	22.3
Other investing activities	1.5	1.9	(5.8)
Cash used in investing activities	(3,251.6)	(1,547.7)	(3,246.9)
Financing activities:			
Borrowings under debt agreements	6,484.4	7,494.2	13,255.5
Repayments of debt	(5,344.4)	(7,766.7)	(10,514.9)
Debt issuance costs	(22.5)	(14.9)	(27.5)
Cash distributions paid to partners	(307.7)	(266.7)	(213.1)
Cash distributions paid to noncontrolling interest	(1,478.4)	(1,322.1)	(1,182.1)
Cash contributions from noncontrolling interest	1,103.7	1,014.2	446.4
Net cash proceeds from issuance of common units	528.5	--	--
Acquisition of treasury units	(3.8)	(2.1)	(1.9)
Other financing activities	1.3	0.2	(66.5)
Cash provided by (used in) financing activities	961.1	(863.9)	1,695.9
Effect of exchange rate changes on cash	0.7	(0.2)	(0.5)
Net change in cash and cash equivalents	9.5	(1.3)	15.4
Cash and cash equivalents, January 1	55.3	56.8	41.9
Cash and cash equivalents, December 31	$65.5	$55.3	$56.8

See Notes to Consolidated Financial Statements.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 13 for Unit History and Accumulated Other Comprehensive Income (Loss))
(Dollars in millions)

	Partners' Equity				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2007	$2,079.1	$**	$ (22.3)	$ 7,473.5	$9,530.3
Net income	164.0	**	--	981.1	1,145.1
Operating lease expenses paid by EPCO	0.1	--	--	1.9	2.0
Cash distributions paid to partners	(213.1)	**	--	--	(213.1)
Cash distributions paid to noncontrolling interest	--	--	--	(1,182.1)	(1,182.1)
Cash contributions from noncontrolling interest	--	--	--	446.4	446.4
Acquisition of treasury units	--	--	--	(1.9)	(1.9)
Issuance of units by subsidiary in connection with an acquisition (see Note 10)	--	--	--	186.6	186.6
Amortization of equity-based awards	1.1	--	--	13.1	14.2
Acquisition of additional noncontrolling interests in subsidiaries	--	--	--	(22.3)	(22.3)
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.1)	(1.2)	(1.3)
Foreign currency translation adjustment	--	--	(0.1)	(2.4)	(2.5)
Change in value of cash flow hedges	--	--	(20.8)	(111.3)	(132.1)
Proportionate share of other comprehensive loss of unconsolidated affiliate	--	--	(9.9)	--	(9.9)
Balance, December 31, 2008	2,031.2	**	(53.2)	7,781.4	9,759.4
Net income	204.1	**	--	936.2	1,140.3
Operating lease expenses paid by EPCO	--	--	--	0.7	0.7
Cash distributions paid to partners	(266.7)	**	--	--	(266.7)
Cash distributions paid to noncontrolling interest	--	--	--	(1,322.1)	(1,322.1)
Cash contributions from noncontrolling interest	--	--	--	1,014.2	1,014.2
Acquisition of treasury units	--	--	--	(2.1)	(2.1)
Deconsolidation of Texas Offshore Port System	--	--	--	(33.4)	(33.4)
Acquisition of interest in subsidiary	--	--	--	10.3	10.3
Amortization of equity-based awards	3.8	--	--	20.8	24.6
Foreign currency translation adjustment	--	--	0.1	2.0	2.1
Change in value of cash flow hedges	--	--	17.3	126.0	143.3
	--	--	2.5	--	2.5

Proportionate share of other comprehensive income of unconsolidated affiliate					
Balance, December 31, 2009	1,972.4	**	(33.3)	8,534.0	10,473.1
Net income	320.8	**	--	1,062.9	1,383.7
Operating lease expenses paid by EPCO	0.1	--	--	0.6	0.7
Cash distributions paid to partners	(307.7)	--	--	--	(307.7)
Cash distributions paid to noncontrolling interest	--	--	--	(1,478.4)	(1,478.4)
Cash contributions from noncontrolling interest	--	--	--	1,103.7	1,103.7
Acquisition of treasury units	(0.3)	--	--	(3.5)	(3.8)
Net cash proceeds from issuance of common units	528.5	--	--	--	528.5
Amortization of equity-based awards	7.6	--	--	51.9	59.5
Common units issued in exchange of equity interest in trucking business	1.8	--	--	36.0	37.8
Common units issued in connection with acquisition of marine shipyard business	--	--	--	99.7	99.7
Foreign currency translation adjustment	--	--	0.9	--	0.9
Change in value of cash flow hedges	--	--	(9.4)	2.2	(7.2)
Issuance of common units pursuant to Holdings Merger (see Note 1)	8,883.5	--	(1.3)	(8,882.2)	--
Proportionate share of other comprehensive income of unconsolidated affiliate	--	--	10.2	--	10.2
Other	--	**	0.4	(0.3)	0.1
Balance, December 31, 2010	$11,406.7	$--	$ (32.5)	$ 526.6	$11,900.8

See Notes to Consolidated Financial Statements.

** Amount is negligible.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

SIGNIFICANT RELATIONSHIPS REFERENCED IN THESE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

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. See Note 23 for information regarding Enterprise’s February 22, 2011 offer to acquire the publicly-held common units of Duncan Energy Partners.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 5 for additional information.

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. The SEC maintains an Internet website at www.sec.gov that contains periodic reports and other information regarding these registrants.

Note 1. Partnership Operations and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. 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. Our assets include: more than 50,200 miles of onshore and offshore pipelines; approximately 190 million barrels ("MMBbls") of storage capacity for NGLs, refined products and crude oil; and approximately 27 billion cubic feet ("Bcf") of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 14 for additional information regarding our business segments.

We are 100% owned 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. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 15 for information regarding the ASA and other related party matters.

Basis of Presentation

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 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.

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 810-10-45, Consolidation – Overall – Changes in Parent's Ownership Interest in a Subsidiary. The Holdings Merger results in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise 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 it were Holdings from an accounting perspective (i.e., the financial statements of Holdings become the historical financial statements of Enterprise). The primary differences between Holdings' and Enterprise's consolidated results of operations were: (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 13 for additional information regarding noncontrolling interests.

The historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the

Holdings Merger. See Note 17 for additional information regarding earnings per unit.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

TEPPCO Merger. On October 26, 2009, the related mergers of Enterprise and its wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, received 1.24 of our common units for each TEPPCO unit they owned. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP.

The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with us originally acquired the ownership interests of TEPPCO GP in February 2005.

For periods prior to the TEPPCO Merger, the former owners' share of the income of TEPPCO and TEPPCO GP is a component of net income attributable to noncontrolling interest as reflected on our Statements of Consolidated Operations. Additionally, cash distributions paid to and cash contributions received from the limited partners of TEPPCO are reflected as a component of cash distributions paid to and cash contributions received from noncontrolling interests.

Consolidation of Duncan Energy Partners. For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt. However, neither Enterprise Products Partners nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners. See Note 23 for information regarding Enterprise's February 22, 2011 offer to acquire the publicly-held common units of Duncan Energy Partners.

Deconsolidation of Texas Offshore Port System. In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). In April 2009, we and TEPPCO dissociated from TOPS. As a result, our operating costs and expenses and net income for the year ended December 31, 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment, including that of TEPPCO, in TOPS through the date of dissociation. Additionally, Oiltanking's noncontrolling interest of $33.4 million was removed from our consolidated books and records. The impact on net income attributable to partners was approximately $8.7 million, as nearly all of this loss was absorbed by noncontrolling interests in consolidation.

In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. Our consolidated financial statements for the year ended December 31, 2009 include approximately $66.9 million of expense in connection with the payment of this cash settlement.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the periods presented:

	For Year Ended December 31,		
	2010	2009	2008
Balance at beginning of period	$16.8	$17.7	$21.8
Charged to costs and expenses	2.6	0.1	3.5
Acquisition-related additions and other	1.1	--	--
Payments and other	(2.1)	(1.0)	(7.6)
Balance at end of period	$18.4	$16.8	$17.7

See "Credit Risk Due to Industry Concentrations" in Note 19 for additional information.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third-party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 13 for information regarding noncontrolling interest.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% unless we have virtually no influence over the entity's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

We account for investments using the cost method when our ownership interest in an entity does not provide us with significant influence or when we have virtually no influence over the investee's

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

operating and financial policies. We currently do not have any investments accounted for using the cost method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2010 and 2009, deferred revenues totaled $113.9 million and $106.8 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis. We also apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market value for these items on the balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received. See Note 6 for additional information regarding our derivative instruments and related hedging activities.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. Earnings per unit in these consolidated financial statements has been retroactively presented in connection with the Holdings Merger. See Note 17 for additional information regarding our earnings per unit.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2010, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the periods presented:

	For Year Ended December 31,		
	2010	2009	2008
Balance at beginning of period	$16.7	$22.3	$30.5
Charged to costs and expenses	2.8	1.9	3.1
Acquisition-related additions and other	0.9	--	2.9
Payments and other	(8.0)	(7.5)	(14.2)
Balance at end of period	$12.4	$16.7	$22.3

At December 31, 2010 and 2009, $3.7 million and $6.4 million, respectively, of our environmental reserves were classified as current liabilities.

Equity-based Awards

See Note 5 for information regarding our accounting for equity-based awards.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

Liquids Exchange Contracts

Liquids exchange contracts are agreements related to the movement of NGLs, crude oil and petrochemical and refined products between parties to satisfy timing and logistical needs of the parties. Volumes borrowed from us under liquids exchange contracts are valued at marked-based prices and included in accounts receivable. Volumes loaned to us under liquids exchange contracts are valued at market-based prices and included in accrued product payables. To the extent that we have both exchange receivables and payables with the same counterparty outstanding at each reporting date, these amounts are netted and presented as either a net exchange receivable or net exchange payable, as the case may be.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs with a counterparty, such items are recognized in our consolidated financial statements on a net basis as either operating revenues or expense, as appropriate.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses and other current liabilities (excluding derivative instruments) are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed-rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 6 for fair value information associated with our derivative instruments.

The following table presents the estimated fair values of our financial instruments (excluding derivative instruments) at the dates indicated:

	December 31, 2010		December 31, 2009	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents and restricted cash	$164.2	$164.2	$118.9	$118.9
Accounts receivable	3,836.9	3,836.9	3,137.4	3,137.4
Financial liabilities:				
Accounts payable and accrued expenses	5,092.8	5,092.8	4,106.1	4,106.1
Other current liabilities	344.4	344.4	341.7	341.7
Fixed-rate debt (principal amount)	12,032.7	12,913.0	10,586.7	11,056.2
Variable-rate debt	1,493.8	1,493.8	1,791.8	1,791.8

Foreign Currency Translation

We own an NGL and natural gas marketing business located in Canada. The financial statements of this foreign subsidiary were translated into U.S. dollars from the Canadian dollar using the current rate method. Currency exchange rate gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive loss in the accompanying Consolidated Balance Sheets. See Note 6 for information regarding our foreign currency derivative instruments.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, technological obsolescence of assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. See Note 6 for information regarding impairment charges related to goodwill during 2009.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges related to long-lived assets during 2010 and 2009.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. We had no such impairment charges during the periods presented.

Income Taxes

Provision for income taxes primarily relates to our state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie Pipeline Company ("Dixie"), both of which are consolidated subsidiaries of ours. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner's tax basis in our limited partner interests, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

We must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized. See Note 16 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are valued at the lower of average cost or market ("LCM"). We capitalize, as a cost of inventory, shipping and handling charges associated with purchased volumes, terminal storage fees, vessel inspection costs, demurrage charges and other related costs. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 7 for additional information regarding our inventories.

Natural Gas Imbalances

In the natural gas pipeline transportation business, volumetric imbalances frequently result from differences in natural gas received from and delivered to customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the agreement.

We settle pipeline gas imbalances with our customers through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices,

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

including negotiated settlements. As imbalances occur, they may be settled: (i) on a monthly basis, (ii) at the end of the underlying transportation agreement or (iii) at other times in accordance with industry practice. The majority of such settlements are through in-kind arrangements whereby an imbalance volume is incrementally delivered to or received from a customer over several periods. However, certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices. In some cases, settlements of imbalances that built up over a period of time are ultimately cashed out at negotiated values which approximate average market prices over a period of time.

For gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates. The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2010	2009
Natural gas imbalance receivables (1)	$22.8	$24.1
Natural gas imbalance payables (2)	31.9	19.0

(1) Reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets.
(2) Reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. With respect to midstream energy assets such as natural gas gathering systems that are reliant upon a specific natural resource basin for throughput volumes, the anticipated useful economic life of such assets may be limited by the estimated life of the associated natural resource basin from which the assets derive benefit. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of (i) the remaining lease term or (ii) the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would prospectively impact our depreciation expense amounts. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values or (iv) significant changes in the forecast life of the applicable resource basins, if any. See Note 8 for additional information regarding our property, plant and equipment.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities for plant operations; however, the cost of annual planned major maintenance projects are deferred and recognized ratably until the next planned outage. With regard to the planned major maintenance activities on our marine transportation assets, we use the deferral method to account for such costs. Under this method, major maintenance costs are capitalized and amortized over the period to the next major overhaul.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas, crude oil and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At December 31, 2010 and 2009, our restricted cash amounts were $98.7 million and $63.6 million, respectively. See Note 6 for information regarding derivative instruments and hedging activities.

Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. See Note 4 for additional information regarding our revenue recognition policies.

Note 3. Recent Accounting Developments

The following recent accounting developments will or may affect our future financial statements:

Disclosure of Supplementary Pro Forma Information for Business Combinations. In December 2010, the Financial Accounting Standards Board (or "FASB") issued an accounting standards update that affects any public entity that enters into business combinations that are material on an individual or aggregate basis. The comparative financial statements should present and disclose pro forma revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. Additionally, disclosures are required to include a description of the nature and amount of any material, nonrecurring pro forma adjustments directly attributable to the business combination(s) included in the reported pro forma revenue and earnings. The new disclosure requirements are effective prospectively for business combinations for which the acquisition date occurs on or after January 1, 2011. We do not believe the new disclosure requirements will have a material impact to our notes to the consolidated financial statements.

Roadmap to Adoption of International Financial Reporting Standards. In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently,

Table of Contents

the FASB, which is based in Norwalk, Connecticut and the IASB are working both individually and jointly on a number of accounting standard convergence projects that, if finalized in 2011 and coming years, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS, with the expectation that any decision to adopt IFRS will allow U.S. issuers a number of years to transition from current U.S. GAAP. We continue to monitor developments regarding the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

Fair Value Measurements. Based on FASB guidance issued during 2010, companies will need to present purchases, sales, issuances and settlements whose fair values are based on unobservable inputs on a gross basis effective with the first quarter of 2011. Other than requiring enhanced fair value disclosures, we do not expect our adoption of this guidance will have a material impact on our consolidated financial statements.

Note 4. Revenue Recognition

The following information provides a general description of our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

The NGL Pipelines & Services 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 and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (i.e. 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 under NGL marketing sales contracts. Revenue under our percent-of-liquids contracts is recognized the same way, 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 the remaining percentage of mixed NGLs we extract. 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.

Our NGL marketing activities generate revenue from the sale and delivery of NGLs we take title to through our processing activities and open market and contract purchases from third parties. Revenue from these sales contracts is recognized when the NGLs are delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for factors such as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

Table of Contents

We collect storage revenue 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). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence. We charge other customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). Certain of our NGL fractionation facilities generate revenue using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer’s fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenue from import and export terminaling activities is recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to our export terminal operations, revenue may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenue is recognized when the customer fails to utilize the specified export facility as required by contract.

Onshore Natural Gas Pipelines & Services

The Onshore Natural Gas Pipelines & Services 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 natural gas marketing activities.

Our onshore natural gas pipelines typically generate revenues from transportation agreements in which shippers are billed a fee per unit of volume transported (typically per million British thermal units, or “MMBtus”) 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. Revenue under firm capacity reservation agreements is recognized in the period the services are provided.

Revenue from natural gas storage contracts typically has two components: (i) monthly demand payments, which are associated with a customer’s storage capacity reservations, and (ii) storage fees per unit of volume stored at our facilities. Revenue from demand payments is recognized during the period the customer reserves capacity. Revenue from storage fees is recognized in the period the services are provided.

Our natural gas marketing activities generate revenue from the sale and delivery of natural gas purchased from third parties on the open market. Revenue from these sales contracts is recognized when the natural gas is delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Onshore Crude Oil Pipelines & Services

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

Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenue associated with these arrangements is recognized when volumes have been delivered.

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. Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Revenue is also generated from fee-based trade documentation services and is recognized as services are completed.

Our crude oil marketing activities generate revenue from the sale and delivery of crude oil obtained from producers or on the open market. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

The Offshore Pipelines & Services segment includes our (i) offshore natural gas pipelines, (ii) offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms, which serve some of the most active drilling and development regions in the Gulf of Mexico.

Revenue from our offshore pipelines is 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. Revenue associated with these fee-based contracts and tariffs is recognized when volumes have been delivered.

Revenue from offshore platform services generally consists of demand fees and commodity charges. Revenue from platform services is recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer actually delivers to the platform. Revenue from commodity charges is based on a fixed-fee per unit of volume delivered to the platform (typically per million cubic feet 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. Our Independence Hub offshore platform earns a significant amount of demand revenue. The Independence Hub platform will earn $54.6 million of demand fees annually through March 2012.

Petrochemical & Refined Products Services

The Petrochemical & Refined Products Services segment includes (i) propylene fractionation plants and related marketing activities, (ii) butane isomerization facilities, (iii) octane enhancement and high purity isobutylene facilities, (iv) refined products pipelines, including our Products Pipeline System, and related marketing activities and (v) marine transportation assets and other services.

Our propylene fractionation and butane isomerization facilities generate revenue through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and butane isomerization. Revenue resulting from such agreements is recognized in the period the services are provided.

Our petrochemical marketing activities generate revenue from the sale and delivery of products obtained through our propylene fractionation activities and purchases of petrochemical products on the open market. Revenue from these sales contracts is recognized when such products are delivered to customers. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location.

Our refined products pipelines, including our Products Pipeline System, generate revenues through fee-based contracts or tariffs as customers are billed a fixed fee per barrel of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenue associated with these fee-based contracts and tariffs is recognized when volumes have been delivered. Revenue from our refined products storage facilities is based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. Under these contracts, revenue is recognized ratably over the length of the storage period. Revenue from product terminaling activities is recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of inland and offshore marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is typically based on set day rates or a set fee per cargo movement. Most of the marine services transportation contracts include escalation provisions to recover increased operating costs such as incremental increases in labor. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

The results of operations from the distribution of lubrication oils and specialty chemicals are dependent on the sales price that we charge our customers. Likewise, revenue from the production and sale of octane additives and high purity isobutylene is dependent on the sales price and volume of such commodities sold to customers. Revenue is recognized for sales transactions when the product is delivered.

Note 5. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the expense we recognized in connection with equity-based awards for the periods presented:

	For Year Ended December 31,		
	2010	2009	2008
Restricted common unit awards (1)	$31.5	$13.6	$11.3
Unit option awards	3.4	2.0	0.7
Employee Partnerships (2)	31.3	9.2	6.6
Other (3)	4.2	0.2	(0.5)
Total compensation expense	$70.4	$25.0	$18.1

(1) The increase between periods is primarily due to a change in vesting provisions beginning with restricted common unit awards granted in 2010 (see below).
(2) The increase between periods is primarily due to the liquidation of the Employee Partnerships in August 2010.
(3) Primarily consists of unit appreciation rights ("UARs"), phantom units and similar awards, which are immaterial to our consolidated financial statements.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-

Table of Contents

classified awards (e.g., UARs and phantom units) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At December 31, 2010, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"), the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan").

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through December 31, 2010, a total of 1,302,085 additional common units could be issued.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through December 31, 2010, a total of 5,945,967 additional common units could be issued.

The 2010 Plan, which became effective in February 2010, provides for awards to employees, directors or consultants providing services to Duncan Energy Partners. Awards under the 2010 Plan may be granted in the form of options to purchase Duncan Energy Partners' common units, restricted common units, UARs, phantom units and DERs. Up to 500,000 of Duncan Energy Partners' common units may be issued as awards under the 2010 Plan. After giving effect to awards granted under the plan through December 31, 2010, a total of 493,652 additional common units could be issued.

The 2006 Plan provided for awards of our common units (formerly of TEPPCO units) and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 Plan were granted in the form of unit options, restricted common units, phantom units, UARs and DERs. Effective upon the consummation of the TEPPCO Merger (see Note 1), we assumed the vested and unvested options, restricted common units and UAR awards outstanding on October 26, 2009 under the 2006 Plan and converted them into our options, restricted common units and UAR awards based on the TEPPCO Merger exchange ratio. The vesting terms of each award and other provisions of the plan remain unchanged.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire (at no cost to the recipient apart from service or other conditions) limited partner units once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. Restricted common unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted common unit awards are typically subject to graded vesting provisions in which one-fourth of each award vests on the first, second, third and fourth anniversaries of the date of grant. As used in the context of EPCO's long-term incentive plans, the term "restricted common unit" represents a time-vested unit. Such awards are non-vested until the required service period expires. Restricted common units are a component of common units as presented on our Consolidated Balance Sheets.

The fair value of a restricted common unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents information regarding restricted common unit awards for the periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise restricted common unit awards:		
Restricted common units at December 31, 2007	1,688,540	$27.23
Granted (2)	766,200	$30.73
Vested	(285,363)	$23.11
Forfeited	(88,777)	$26.98
Restricted common units at December 31, 2008	2,080,600	$29.09
Granted (3)	1,025,650	$24.89
Vested	(281,500)	$26.70
Forfeited	(411,884)	$28.37
Awards assumed in connection with TEPPCO Merger	308,016	$27.64
Restricted common units at December 31, 2009	2,720,882	$27.70
Granted (4,5)	1,393,925	$32.60
Vested (5)	(383,628)	$25.51
Forfeited	(169,565)	$29.87
Restricted common units at December 31, 2010	3,561,614	$29.78
Duncan Energy Partners restricted common unit awards:		
Restricted common units at December 31, 2009	--	
Granted (5,6)	6,348	$25.26
Vested (5)	(6,348)	$25.26
Restricted common units at December 31, 2010	--	
Holdings restricted common unit awards:		
Restricted common units at December 31, 2009	--	
Granted (5,7)	3,424	$41.47
Vested (5)	(3,424)	$41.47
Restricted common units at December 31, 2010	--	

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued. With respect to restricted common unit awards assumed in connection with the TEPPCO Merger, the weighted-average grant date fair value per unit was determined by dividing the aggregate grant date fair value of the assumed awards before an allowance for forfeitures by the number of awards assumed.
(2) Aggregate grant date fair value of restricted common unit awards issued during 2008 was $23.5 million based on grant date market prices of our common units ranging from $25.00 to $32.31 per unit. An estimated forfeiture rate of 17% was applied to these awards.
(3) Aggregate grant date fair value of restricted common unit awards issued during 2009 was $25.5 million based on grant date market prices of our common units ranging from $20.08 to $28.73 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

(4) Aggregate grant date fair value of restricted common unit awards issued during 2010 was $45.4 million based on grant date market prices of our common units ranging from $32.00 to $43.18 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

(5) Includes awards granted to the independent directors of the boards of directors of EPGP, DEP GP and EPE Holdings as part of their annual compensation for 2010. A total of 6,960, 6,348 and 3,424 restricted common unit awards were issued in February 2010 to the independent directors of EPGP, DEP GP and EPE Holdings, respectively, that immediately vested upon issuance.

(6) Aggregate grant date fair value of restricted common unit awards issued during 2010 denominated in Duncan Energy Partners' common units was $0.2 million based on a grant date market price of Duncan Energy Partners' common units of $25.26 per unit.

(7) Aggregate grant date fair value of restricted common unit awards issued during 2010 denominated in Holdings' units was $0.1 million based on a grant date market price of Holdings' units of $41.47 per unit.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid by the respective issuer. Since these restricted common units are participating securities, such distributions are reflected as a component of cash distributions to noncontrolling interest as shown on our Statements of Consolidated Cash Flows. The following table presents cash distributions with respect to our

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

restricted common units and supplemental information regarding our restricted common units for the periods presented:

	For Year Ended December 31,		
	2010	2009	2008
Cash distributions paid to restricted common unit holders	$8.0	$5.2	$3.9
Total fair value of restricted common unit awards vesting during period	9.8	7.5	6.6

In the aggregate, unrecognized compensation cost of restricted common unit awards was $45.0 million at December 31, 2010, of which our allocated share of the cost is currently estimated to be $42.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These option awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. When issued, the exercise price of each option award may be no less than the market price of the underlying security on the date of grant. In general, option awards have a vesting period of four years from the date of grant. If option awards are not exercised, these awards generally expire between five and ten years after the date of grant.

The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of the underlying security's historical unit price volatility and distribution yield over a period equal to the expected life of the option. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the vesting period.

During 2008, in response to changes in the federal tax code applicable to certain types of equity-based awards, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents unit option activity for the periods presented. As of December 31, 2010, only Enterprise Products Partners has issued unit option awards.

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit options at December 31, 2007	2,315,000	$ 26.18		
Granted (2)	795,000	$ 30.93		
Exercised	(61,500)	$ 20.38		
Forfeited	(85,000)	$ 26.72		
Unit options at December 31, 2008	2,963,500	$ 27.56		
Granted (3)	1,460,000	$ 23.46		
Exercised	(261,000)	$ 19.61		
Forfeited	(930,540)	$ 26.69		
Awards assumed in connection with TEPPCO Merger	593,960	$ 26.12		
Unit options at December 31, 2009	3,825,920	$ 26.52		
Granted (4)	785,000	$ 32.26		
Exercised	(857,500)	$ 24.98		
Unit options at December 31, 2010 (5)	3,753,420	$ 28.08	3.6	$--
Unit options exercisable at:				
December 31, 2008	548,500	$ 21.47	4.1	$--
December 31, 2009	447,500	$ 25.09	4.8	$2.8
December 31, 2010 (5)	--	$ --	--	$--

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options issued during 2008 was $1.9 million based on the following assumptions: (i) a grant date market price of our common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on our common units of 7.0% and (v) expected unit price volatility on our common units of 19.8%. An estimated forfeiture rate of 17% was applied to awards granted during 2008.
(3) Aggregate grant date fair value of these unit options issued during 2009 was $8.1 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $23.46 per unit; (ii) weighted-average expected life of options of 4.8 years; (iii) weighted-average risk-free interest rate of 2.1%; (iv) weighted-average expected distribution yield on our common units of 9.4% and (v) weighted-average expected unit price volatility on our common units of 57.4%. An estimated forfeiture rate of 17% was applied to awards granted during 2009.
(4) Aggregate grant date fair value of these unit options issued during 2010 was $2.3 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $32.26 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.5%; (iv) weighted-average expected distribution yield on our common units of 6.9%; and (v) weighted-average expected unit price volatility on our common units of 23.3%. An estimated forfeiture rate of 17% was applied to awards granted during 2010.
(5) We were committed to issue 3,753,420 and 3,825,920 of our common units at December 31, 2010 and 2009, respectively, if all outstanding options awarded (as of these dates) were exercised. Of the option awards outstanding

at December 31, 2010, 712,280, 736,000, 1,520,140 and 785,000 will vest in 2011, 2012, 2013 and 2014, respectively. These unit option awards become exercisable in the calendar year following the year in which they vest.

The following table presents supplemental information regarding our unit options:

	For Year Ended December 31,		
	2010	2009	2008
Total intrinsic value of option awards exercised during period	$10.6	$2.4	$0.6
Cash received from EPCO in connection with the exercise of unit option awards	7.2	1.7	0.7
Unit option-related reimbursements to EPCO	10.6	2.4	0.6

In the aggregate, unrecognized compensation cost of unit option awards was $6.5 million at December 31, 2010, of which our allocated share of the cost is currently estimated to be $6.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unit Appreciation Rights

UARs entitle a participant to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of the underlying security (determined as of a future vesting date) over the grant date fair value of the award. UARs are accounted for as liability awards. The following tables present information regarding UARs for the periods presented:

	UARs Based on Units of			
	TEPPCO	Enterprise Products Partners	Holdings	Total
UARs at December 31, 2007	401,948	--	180,000	581,948
Granted	29,429	--	--	29,429
UARs at December 31, 2008	431,377	--	180,000	611,377
Settled or forfeited	(166,217)	(186,614)	(90,000)	(442,831)
Awards assumed in connection with the TEPPCO Merger	(265,160)	328,810	--	63,650
UARs at December 31, 2009	--	142,196	90,000	232,196
Settled, forfeited or cancelled	--	(107,092)	(90,000)	(197,092)
Awards assumed in connection with the Holdings Merger	--	135,000	--	135,000
UARs at December 31, 2010 (1)	--	170,104	--	170,104

(1) Balance at December 31, 2010, consists of 125,104 UARs granted under the 2006 Plan and 45,000 remaining under a letter agreement.

	At December 31,	
	2010	2009
Accrued liability for UARs	$ 1.0	$ 0.3

At December 31, 2010, 125,104 UARs had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf. These awards are subject to five-year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on a unit price of $37.00 for our common units. If the employee resigns prior to vesting, the UARs are forfeited.

Prior to the Holdings Merger, the non-employee directors of EPE Holdings, formerly the general partner of Holdings, were granted 90,000 Holdings UARs in the form of letter agreements. These liability awards were not part of any established long-term incentive plan of EPCO, Holdings or us. The compensation expense associated with these awards was recognized by EPE Holdings, which was wholly owned by Dan Duncan LLC. At the effective date of the Holdings Merger, these awards converted into Enterprise UARs at an exchange ratio of 1.5 Enterprise UARs for each Holdings UAR (i.e., resulting in 135,000 Enterprise UARs). In December 2010, 90,000 of the Enterprise UARs were surrendered and cancelled. In January 2011, the remaining 45,000 Enterprise UARs were surrendered and cancelled.

Prior to the TEPPCO Merger, 95,654 UARs had been granted to the non-employee former directors of TEPPCO under the 2006 Plan. The awards were settled in October 2009 and $0.1 million in cash was paid to the former directors.

Prior to the Holdings Merger, the non-employee directors of DEP GP, the general partner of Duncan Energy Partners, were granted 90,000 Holdings UARs in the form of letter agreements. These liability awards were not part of any established long-term incentive plan of EPCO, Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards was recognized by DEP GP, which is our consolidated subsidiary. At the effective date of the Holdings Merger, these awards were settled and $2.5 million in cash was paid out to the non-employee directors of DEP GP.

UARs formerly issued to non-employee directors of EPGP in the form of letter grants were terminated during the second quarter of 2009.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Employee Partnerships

EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, limited partnership interests in the Employee Partnerships. These partnerships were liquidated in August 2010. Prior to liquidation, the limited partnership interests entitled each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. Each Employee Partnership owned either our common units or Holdings' units or a combination of both.

We recognized $26.8 million of expense in connection with the liquidation of the Employee Partnerships, of which $21.7 million was attributed to noncontrolling interest. Of this expense amount, $18.9 million was non-cash.

The grant date fair value of each Employee Partnership was based on (i) the estimated value of the assets, as determined using a Black-Scholes option pricing model, forecast to be distributed to the Class B limited partners upon dissolution of the Employee Partnerships plus (ii) the estimated value, based on a discounted cash flow analysis using appropriate discount rates, of the quarterly cash distributions that the Class B limited partners were forecast to receive (if any) over the assumed life of the Employee Partnership.

On an unallocated basis to the EPCO family of companies, the aggregate grant date fair value of the Employee Partnerships was $51.3 million at the time of liquidation, of which $40.4 million was attributable to the estimated value of the assets forecast to be distributed to the Class B limited partners upon dissolution of the Employee Partnerships. The following table presents changes in the aggregate grant date fair value (on an unallocated basis) of the Employee Partnerships for the periods shown:

	For Year Ended December 31,		
	2010	2009	2008
Aggregate grant date fair values at beginning of period	$79.3	$64.6	$35.4
Grant of limited partner interests (1)	--	--	14.6
Modifications (2)	--	19.5	15.0
Other, including forfeiture and regrant activity (3,4)	(28.0)	(4.8)	(0.4)
Liquidation of partnerships	(51.3)	--	--
Aggregate grant date fair values at end of period	$--	$79.3	$64.6

(1) EPCO Unit, Enterprise Unit, TEPPCO Unit L.P. ("TEPPCO Unit") and TEPPCO Unit II L.P. ("TEPPCO Unit II") were formed in 2008.

(2) In December 2009, the expected liquidation date for each Employee Partnership was extended to February 2016. This modification followed a similar set of modifications made in July 2008 for EPE Unit I, EPE Unit II and EPE Unit III that extended liquidation dates as well as reduced the Class A limited partner's preferred return rates. These modifications were intended to align the interests of the Class B partners with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships.

(3) Amount presented for 2009 primarily reflects adjustments due to the dissolution of TEPPCO Unit and TEPPCO Unit II.

(4) Amount presented for 2010 reflects the decrease in fair value attributable to changes in the service period from February 2016 to August 2010 (the liquidation date) for all of the Employee Partnerships. The reduction is attributable to the cash distributions that the Class B limited partners would not receive from each Employee Partnership as a result of the August 2010 liquidations.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As noted previously, we used a Black-Scholes option pricing model to estimate the grant date fair value of the assets forecast to be distributed to the Class B limited partners upon dissolution of the Employee Partnerships. The following table summarizes the assumptions we used in determining the Black-Scholes values for each Employee Partnership:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
EPE Unit I	3 to 6 years	1.2% to 5.0%	3.0% to 6.7%	16.6% to 35.0%
EPE Unit II	4 to 6 years	1.6% to 4.4%	3.8% to 6.4%	18.7% to 31.7%
EPE Unit III	4 to 6 years	1.4% to 4.9%	4.0% to 6.4%	16.6% to 32.2%
Enterprise Unit	4 to 6 years	1.4% to 3.9%	4.5% to 8.4%	15.3% to 31.7%
EPCO Unit	4 to 6 years	1.6% to 2.4%	8.1% to 11.1%	27.0% to 50.0%

Note 6. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

§

Foreign currency exposure - A foreign currency hedge can be treated as either a fair value hedge or a cash flow hedge depending on the risk being hedged.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at December 31, 2010:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.6%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

In September 2010, Duncan Energy Partners' three floating to fix swaps (with a notional amount of $175 million) expired. In November 2010, in connection with the Holdings Merger, Holdings' floating-to-fixed swaps were assigned to us and are accounted for using mark-to-market accounting.

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for a fixed or floating interest rate stipulated in the derivative instrument. Interest expense for the years ended December 31, 2010, 2009 and 2008 includes $16.5 million, $16.2 million and $6.4 million, respectively, attributable to interest rate swaps.

The following table summarizes our forward starting interest rate swaps outstanding at December 31, 2010, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	3 forward starting swaps	$250.0	2/11	3.7%	Cash flow hedge
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	3 forward starting swaps	$150.0	8/12	4.0%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

In May 2010, we settled a forward starting swap with a notional amount of $50.0 million and recognized a gain of $1.3 million in other comprehensive income. In January 2011, we settled the three forward starting swaps with a notional amount of $250 million for a loss of $5.7 million. These amounts will be amortized to earnings using the effective interest method over the forecasted hedged period.

At times, we use treasury lock derivative instruments to hedge the underlying U.S. treasury rates related to forecasted issuances of debt. As cash flow hedges, gains or losses on these instruments are recorded in other comprehensive income (loss) and amortized into earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. During 2008, we terminated treasury locks with a combined notional amount of $1.2 billion and recognized an aggregate loss of $43.9 million in other comprehensive loss related to these terminations.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at December 31, 2010:

	Volume (1)		Accounting
Derivative Purpose	Current	Long-Term (2)	Treatment
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	35.8 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.8 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (4)	n/a	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	2.8 MMBbls	0.2 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	13.4 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	5.9 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	6.9 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	2.6 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of refined products	3.7 MMBbls	0.2 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.4 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	2.1 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	474.3 Bcf	58.9 Bcf	Mark-to-market
Refined products risk management activities (6)	2.0 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	0.1 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	2.8 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives included in the long-term column is December 2013.

(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.
(4) Forecasted purchase volumes of NGLs under Octane enhancement and forecasted sales of NGL volumes under Natural gas processing exclude 1.7 MMBbls and 2.8 MMBbls, respectively, of additional hedges executed under contracts that have been designated as normal purchase/sales agreements.
(5) Current and long-term volumes include approximately 162.5 Bcf and 6.9 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2011, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Certain basis swaps, basis spread options and other financial derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

Foreign Currency Derivative Instruments

Prior to January 1, 2011, we were exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. In order to manage this risk, we entered into foreign exchange purchase contracts to lock in a currency exchange rate. Prior to the third quarter of 2010, long-term currency hedging transactions (i.e., those having terms of more than two months) were accounted for as cash flow hedges and shorter term transactions were accounted for using mark-to-market accounting.

At December 31, 2010, we had entered into offsetting foreign currency derivative instruments and our foreign currency portfolio had a zero notional amount of Canadian dollars. The fair market value of these derivative instruments was an asset of $0.2 million at December 31, 2010 and the total portfolio is accounted for using mark-to-market accounting.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At December 31, 2010, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $2.3 million, all of which was subject to a credit rating contingent feature. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on
Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	December 31, 2010		December 31, 2009		December 31, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 30.3	Other current assets	$ 32.7	Other current liabilities	$ 5.5	Other current liabilities	$ 18.6
Interest rate derivatives	Other assets	77.8	Other assets	31.8	Other liabilities	26.2	Other liabilities	6.7
Total interest rate derivatives		108.1		64.5		31.7		25.3
Commodity derivatives	Other current assets	46.3	Other current assets	52.0	Other current liabilities	93.0	Other current liabilities	62.6
Commodity derivatives	Other assets	1.0	Other assets	0.5	Other liabilities	1.7	Other liabilities	1.8
Total commodity derivatives (1)		47.3		52.5		94.7		64.4
Foreign currency derivatives	Other current assets	--	Other current assets	0.2	Other current liabilities	--	Other current liabilities	--
Total derivatives designated as hedging instruments		$ 155.4		$ 117.2		$ 126.4		$ 89.7
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 21.0	Other current liabilities	$ --
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	0.9	Other liabilities	--
Total interest rate derivatives		--		--		21.9		--

Commodity derivatives	Other current assets	38.6	Other current assets	28.9	Other current liabilities	41.2	Other current liabilities	24.9
Commodity derivatives	Other assets	4.5	Other assets	2.0	Other liabilities	5.4	Other liabilities	2.7
Total commodity derivatives		43.1		30.9		46.6		27.6
Foreign currency derivatives	Other assets	0.3	Other assets	--	Other liabilities	0.1	Other liabilities	--
Total derivatives not designated as hedging instruments		$ 43.4		$ 30.9		$ 68.6		$ 27.6

(1) Represents commodity derivative instrument transactions that have either not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the periods presented:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative For Year Ended December 31, 2010	2009	2008
Interest rate derivatives	Interest expense	$16.3	$(8.8)	$31.2
Commodity derivatives	Revenue	3.3	1.8	--
Total		$19.6	$(7.0)	$31.2

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item For Year Ended December 31, 2010	2009	2008
Interest rate derivatives	Interest expense	$(16.2)	$3.2	$(31.2)
Commodity derivatives	Revenue	(2.6)	(1.3)	--
Total		$(18.8)	$1.9	$(31.2)

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations and Statements of Consolidated Comprehensive Income for the periods presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion) For Year Ended December 31, 2010	2009	2008
Interest rate derivatives	$(0.1)	$12.5	$(73.0)
Commodity derivatives – Revenue	(7.7)	(34.8)	(34.8)
Commodity derivatives – Operating costs and expenses	(68.6)	(144.8)	(135.4)
Foreign currency derivatives	(0.1)	(10.2)	9.3
Total	$(76.5)	$(177.3)	$(233.9)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/Loss to Income (Effective Portion) For Year Ended December 31, 2010	2009	2008
Interest rate derivatives	Interest expense	$(25.6)	$(26.4)	$(5.5)
Commodity derivatives	Revenue	2.1	(61.0)	(56.7)
Commodity derivatives	Operating costs and expenses	(46.1)	(233.2)	(39.6)
Foreign currency derivatives	Other expense	0.3	--	--
Total		$(69.3)	$(320.6)	$(101.8)

Derivatives in Cash Flow Hedging Relationships	Location